Mathematical & Computer Modelling

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Ynon Gablinger
OFGEM

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Dear Ynon,

Consultation response
Electricity distribution charging methodologies:
DNOs' proposals for the higher voltages
Paper 67/11 May 2011

Please find attached a response to your recent consultation. As you will appreciate the detailed working has become ever more complex and there are no 'right' answers to some of the issues that need to be faced. What is now being proposed is very much a compromise achieved after much interaction between the various DNOs, other stakeholders, and OFGEM. It falls a long way short of OFGEM's original idealised economic model, but this did not reflect the reality of the need to raise the allowed revenue without imposing grossly 'unfair' charges. It is disappointing to realise that this has taken over 10 years to reach fruition and in my view at least, we still haven't yet satisfactorily sorted out how to handle embedded generation. OFGEM need to give some thought as to how they handle such projects in the future. Perhaps anticipating the difficulty, some DNOs were probably not initially as engaged in the project as OFGEM would have liked, but this was compounded by the intransigence of OFGEM when DNOs did become engaged, in refusing to recognise the possibility of any errors in OFGEM's thinking.

The complexity of the present proposals must be a worry. At present there are probably half a dozen people who understand both the principles and the implementation. There are considerable parts of which I have no detailed knowledge and other parts where I have to take it on trust that the principles have been implemented correctly. I haven't made any attempt to check the workings of the spreadsheet or investigate where the data on which the methodology depends comes from. In my experience these areas provide ample room for misunderstandings and outright faults in implementation. While there are still people who possess a broad understanding based on their involvement in the development of the project, it is likely that serious errors will be avoided, but I fear this will not continue into the future.

Please don't hesitate to contact me if you should have any queries on the response.

Yours sincerely,

Robin Hodgkins

Electricity distribution charging methodologies:

DNOs' proposals for the higher voltages: OFGEM paper 67/11

Response by Mathematical & Computer Modelling

June 2011

The present consultation relates to the proposals presented to OFGEM by the DNOs on 1st.April 2011. In most respects these are the same as those published in December 2010 to which the responses were subsequently issued by the ENA[1]. The main change in the proposals since December 2010 is the decision to apply the 'notional use' method for scaling charges to meet the allowed revenue. In the earlier response it was explained that whilst this could be considered to be the best approach when evaluating reinforcement costs using LRIC, it is not the most appropriate method for FCP as it unnecessarily distorts the reinforcement message. However, it applies a single approach to both LRIC and FCP.

Part 1 of this document is largely identical to the previous response to the DNOs' consultation and gives a general survey of the proposals, outlining the strengths and weaknesses of the various approaches. Part 2 gives answers to the specific questions posed by OFGEM.

Part 1

Introduction

The introduction of 'cost reflective' concepts in setting DUoS charges has been in progress since 2000. It was driven partly by a recognition that some charges, such as Deep Connection charges, were discouraging the connection of new customers, in particular embedded generation, and also by the absence of locational messages to encourage customers, new customers in particular, to locate in areas which would reduce or even eliminate the need for reinforcement. The initial impetus was driven by idealised economic thinking which asserted that 'cost reflective' implied that charges must be based on forward looking costs and these messages should not be distorted. The potential advantages in terms of savings in capital investment were initially estimated to be of the order of £200m. However, this was based on the supposition of sufficient embedded generation locating appropriately to offset the need to reinforce the network. Given the nature of much embedded generation such as wind power, this is unlikely to be the case.

[1] http://2010.energynetworks.org/edcm-file-storage/6-consultations/07-edcm-consultations-dec-2010-responses/ file: 01.Detailed Responses.zip

It is generally recognised that the distribution network will require major investment in order to accommodate substantial embedded generation and also, but less well defined, new demands such as battery charging for electric vehicles. However, these demands are largely unknown in specific locational terms. A major issue when introducing locational charging for EHV customers is that of the order of 80% of the load on the EHV network arises from HV and LV customers to which the locational price signals are not currently applicable and therefore their demand will not be affected. Thus setting EHV charges at a level which might be necessary in order to avoid the need for reinforcement could be regarded as grossly discriminatory, ultimately forcing EHV customers to close plant whilst the HV network and LV demand continues to increase unchecked. It should also be noted that if EHV customers should wish to increase demand then they would have to pay connection charges towards any network reinforcement required at their voltage level of connection and one level above, not payable by existing users or new users at LV.

OFGEM have requested that DNOs justify their proposed charging schemes. In this context FCP seeks to limit possible discrimination by setting the charges such that over a 10 year period the EHV demand customers would pay only their share of the cost of reinforcement based on the forecast growth rate for each Network Group. LRIC similarly now seeks to limit such discrimination by capping its reinforcement charges to the annuitised rate for an assumed life of 40 years, a very severe capping.

It has to be recognised that setting reinforcement charges at a fair and justifiable level, limits the impact of locational charging in reducing the need for network reinforcement. However, It also needs to be recognised that attaining optimum economic efficiency is a balance between reducing the costs of the Network Operator and increasing the costs to the customer, or vice versa. Methods which minimise the operator's cost alone under monopoly conditions are generally invalid.

A second major issue is, given that reinforcement expenditure driven by growth in demand only accounts for a smallish proportion of the total allowed revenue, there is the necessity for deciding how the rest of the revenue is to be recovered. Some of this can be readily allocated in terms of operating costs or similar items but a substantial residual amount remains for which different methods of recovery (scaling) have been proposed. There are a variety of economic models with conflicting principles and results. All models fall short in some respect, but there is some convergence between methods in the latest proposals.

Because there is overall a gradual change in network demand, the charging models for demand customers, although open to criticism, have a clear basis. The models for charging generation are much more subjective as new generation, at a level sufficient to drive reinforcement of the EHV network, arises in nearly all cases from new generators of a discrete size. When the existing capacity is near exhaustion, then imposing high charges on existing generators which themselves are not requesting increased capacity could be regarded as unjustified and counterproductive since there is no firm requirement to accommodate new generation and if the existing generator were consequently to reduce or cease generation no actual benefit to the DNO would necessarily arise. Further complicating factors are that both FCP and LRIC now ignore switchgear reinforcement, which in practise is generally the limiting factor and largest cost for generation driven reinforcement, and both methods now impose a P2/6 contingency analysis, applicable to demand, but which in general may be inappropriate for generation and which generators themselves are usually averse to funding.

The following sections analyse these points in more detail. Nearly all the comments have been made in previous submissions but there have been significant changes in the proposals over a period of time resulting in a substantial increase in complexity. One serious consequence is the failure to meet the earlier objective of 'transparency', at least in the normally understood sense.

LRIC reinforcement model

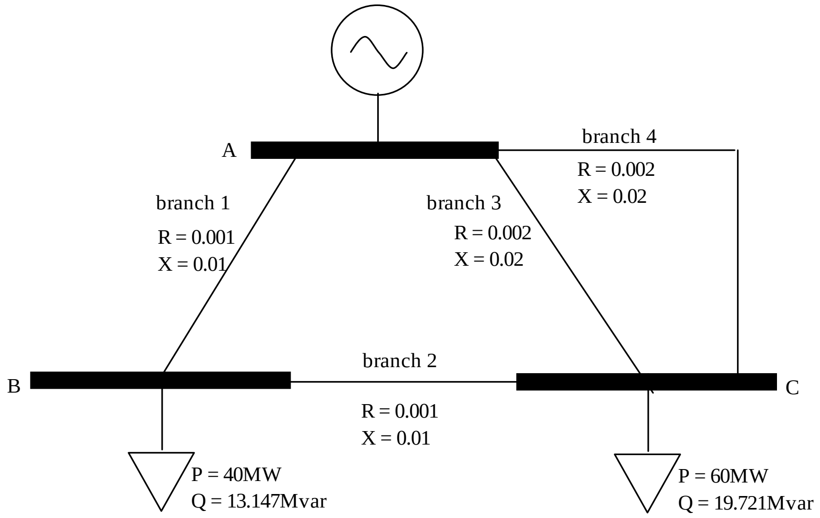
It is appropriate to examine LRIC first as FCP was conceived in order to remedy the perceived flaws of the initial LRIC.

LRIC considers the change (£/kVA) in the Present Value of a future reinforcement brought about by a small increment in demand. To obtain an annual charge rate this is annuitised over the nominal lifetime of the asset of 40 years. The reasoning behind the application of this fixed annuity is faulty, since the charges are not levied over the 40 year period and will cease when reinforcement actually occurs. This leads to failure to pay the actual cost of reinforcement at high growth rates and substantial overcharging at low growth rates, tending to infinity as the growth rate tends to zero and as the demand tends to limiting capacity. LRIC was therefore restricted to apply a constant growth rate of 1% p.a. over the whole network. This leads to the same charge rate at a given level of utilisation being imposed whether demand is increasing, static, or decreasing. Furthermore, at a growth rate of 1%, high charges can result as demand reaches limiting capacity. This has been countered by capping the charge rate to the annuitised value of the cost of reinforcement. The capping is severe. The annuitised rate can be written as $a\,A/C$ where a is the annuity rate based on 40 years corresponding to a discount rate of i, A is the asset cost (£) and C is the capacity (kVA) at which reinforcement is required. The analytic LRIC formula is $a\,A/C\,(i/r)\,\exp(r\,t\,-\,i\,t)$, where t is the years to reinforcement at an annual growth rate of r. For a discount rate of 5.6 % and annual growth rate of 1% the capped rate and the uncapped LRIC rate are approximately equal for a value of t of 37 years. Thus the rate is capped to the annuitised rate if the time to reinforcement is less than 37 years and discrimination over shorter periods than 37 years is lost.

The capping results in a considerable reduction to the charges for reinforcements required in the near and medium term and hence a relatively larger weighting to reinforcements only required in the longer term. This is amplified by the fact that the charges only reduce slowly as the time to reinforcement increases. Since the growth rate over the longer term is very uncertain and the order in which reinforcements occur determines the nature of further reinforcement, there is a lack of focus on the real and imminent need to reinforce.

Networks are designed to meet the contingency conditions defined by the engineering standard P2/6. It is the pattern of flow and demands under these conditions which determine whether reinforcement is required. LRIC applies a security factor which is the ratio of the flow under peak conditions (intact flow) to the flow in the worst contingency condition in order to scale the flows to determine the allocation of charges. However, in many cases this is incorrect. Thus consider the

Example Network described in 6.29 of Appendix A2 Schedule 19 EDCM LRIC Methodology Statement:



Using the tabulated results (6.31, Table 14), the intact flow in Branch 2 is 7.024 MVA from node C towards node B. An increment of 0.1 MVA at node B decreases the flow in Branch 2 by 0.035 MVA to give a flow of 6.989 MVA. The worst contingency in Branch 2 arises when Branch 1 fails and the entire demand flowing in Branch 2 arises from the load at node B. Since in the intact flow the increment at node B reduces the flow in Branch 2, no charge is levied on node B for the reinforcement of Branch 2, yet under the worst contingency condition node B alone is responsible for the flow in Branch 2 and gives an increased flow of 0.1 MVA. Even when the change due to the increment is of the same sign in the normal case and contingency case, the actual values do not usually correspond. Thus in the intact flow an increment of 0.1 MVA at node B gives rise in Branch 3 to an increased flow of 0.018 MVA, approximately 1/6 of the increment. The worst contingency condition for Branch 3 is the loss of Branch 1. In this case half the 0.1 MVA flows via Branch 3 and half via Branch 4. Thus the effect of the increment is 3 times larger whereas the security factor only gives a factor of 1.88.

Where the network flow is radial, such problems do not arise. However, in order to satisfy P2/6, it is usual for much of the EHV network to be meshed in a similar, but more complex fashion, to the Example Network.

This doesn't necessarily mean the costs determined by the method are completely inappropriate, it simply means that LRIC actually sets the charges according to the use of assets under peak intact flow conditions and not according to the effect of the load at each node under contingency conditions which necessitates reinforcement in the future. The values determined could be deemed arbitrary since they depend on the assumption of a 1% growth rate using an incorrect formula. However, since they are capped by the annuitised rate, the worst effects are constrained.

The LRIC model for generation is simply the reverse of the above. It considers increments of 0.1 MW at each node and their effect on the intact flows and the contingency flows. When considering possible benefits arising from generation, this has the advantage of consistency with the demand model although the resulting charges are subject to the same riders applicable to the demand charges. When considering generation charges for a generation dominated asset, there would seem to be no rational basis for assuming a 1% annual increase in generation. Once again the nearest proxy is the utilisation of assets by generation, rather than their effect on reinforcement.

FCP reinforcement model

FCP was initially developed empirically to overcome the deficiencies of LRIC. The demand charging algorithm was later derived by the Present Value approach used in deriving LRIC but with a corrected annuity factor. The charge rates are then scaled to recover future reinforcement costs over the 10 years leading up to reinforcement with no reinforcement costs being levied for reinforcements not required within 10 years. No grossly excessive charges should result and varying growth rates over the network are accommodated in the model. These are based on the forecasts issued in the Long Term Development Statement extended to 10 years. Thus there should be no need to cap reinforcement charges. The period of 10 years is a compromise between a shorter period which would encourage better use of underused assets but set higher charges as reinforcement approaches and a longer period which seemingly would give customers the ability to plan over a longer term, but in view of the considerable uncertainty over long term growth rates, could in practise give misleading signals.

Rather than derive nodal charges, the charges are average charges across each Network Group. This avoids the problems of the scaling factors between the intact flow and the contingency flow. It should also be noted that the pattern of AC flow within a Network Group can be affected by the presence of reactive flows and transformer tap changes, so attributing the total flow through an asset to individual nodal demands can be problematic in meshed networks. It also means that the results are far more readily checked, since the number of charge rates is less and questionable rates can be traced back to the reinforcement of particular assets, with computer results being checked against a manual assessment.

Generation credits where applicable are derived from the demand model. However, since no growth rate can be defined for generation, a different model is used for setting generation charges. This is based upon the forecast total new generation at each voltage level, currently assumed to match the current spread of generation between voltage levels. Again the model is based on Network Groups, looking only 10 years ahead, and the cost of reinforcement is charged against existing generation and the estimated new generation.

One concern about the application of this model is that there is a major lack of knowledge about the amount and incidence of new generation. It is likely that the location of potential generation will vary considerably across a DNO's network and high charges could be set to existing generators in locations where in practise it is highly unlikely that new generation would wish to site. However, as more generation appears on the network, estimates should improve and may become locational in at least a broad sense. In the mean time it may be appropriate to apply the same capping as is applicable to the LRIC generation model.

Two concerns applicable to both the FCP and LRIC generation models are first that the governing factor is rarely the thermal limits on the assets but ability of the switchgear to handle fault currents, so basing the charges solely on thermal limits can give misleading signals.

Secondly it is apparently intended to assume that reinforcement would follow P2/6 rules applicable to demand. This would seem to be a major error, both from the point of view of the network and of the customer. Loss of supply to demand customers can cause major economic damage in lost production or accidents as equipment and control systems lose power, hence the need for P2/6. However, most generators can be switched off if generation exceeds the capacity of the faulted network. This procedure, even if it involves additional switching, is likely to be an order of magnitude cheaper than network reinforcement. There will be some larger generators, in particular nuclear generators, where rapid reduction or cessation of generation could introduce an unacceptable level of thermal cycling. In this case the generator should pay at commissioning for the additional security. Reports from DNOs indicate that nearly all new generators are unwilling to pay for this additional level of security and in practise generation is more likely to be lost because of generation faults than faults on the EHV network. Therefore there would seem to be no reason why existing generators should be charged for a level of security which new customers are unwilling to finance. However, these concerns on setting the charges may be addressed by appropriate Generation Side Management agreements, although this doesn't answer the question of whether some DNOs are overdesigning the network. Where secure access to a local generator is required to meet customer demand, then it is the demand customers that should meet the cost, not the generator.

Scaling

When realistic and justifiable charges are levied for reinforcement, then it is apparent that these only account for a smallish part of the allowed revenue. Earlier checks on FCP showed that the charges set did roughly account for the annual capital expenditure for the level of reinforcements shown to be necessary by the load flows. However, the context in which the charges project arose and is believed to be important is that it is envisaged that the networks will require very large capital expenditure over the next few years in order to ensure security of supply on a network much more dependent on embedded generation. The mismatch here, if it is more than a false perception, doesn't seem to have been investigated. The current demand forecasts show only a small rate of increase in demand, and given efforts to save energy and the absence of an economic boom, overall even the 1% increase in demand assumed by LRIC could be an overestimate. One missing element is the upgrading of switchgear to accommodate new generation. However, this was included in earlier FCP models and would not bridge a large gap in the capital costs. Furthermore, the countervailing contribution of connection charges has been omitted (as mentioned, most new generation chooses a location and size where there is sufficient spare capacity to avoid the need for expensive reinforcement). It would therefore appear that the large investment envisaged by OFGEM and the DNOs is not captured by the charging models and the locational charges may be irrelevant to the largest part of future investment needs. This needs to be urgently explored.

The allowed revenue includes other items of expenditure for asset replacement and non-load driven reinforcements. It would seem reasonable to apply these as a proportion of the MEAV values and charge customers according to the use of these assets. Other items such as operating expenditure can also be attached to the assets at different voltage levels. However, there is still a substantial proportion of the allowed revenue which cannot be directly assigned in this way. Two such large items are, depreciation and return on capital, and pension and pension deficit payments.

A method favoured by economists in situations where setting prices to marginal costs yields insufficient revenue is the so called Ramsey pricing which sets the amount by which the price exceeds the marginal cost, expressed as a percentage of the price, to be greater for goods with less elastic demand. In terms of setting locational prices, the rates for customers which can't easily relocate are increased more than those which can more easily relocate when faced with high locational charges. Large manufacturers may choose to relocate or expand production overseas if faced with increased locational charges. Domestic customers are unlikely to relocate in response to high locational charges. This method was rejected by OFGEM on the grounds that the elasticities are largely unknown and the method could be deemed discriminatory, particularly to small customers not readily able to relocate.

OFGEM instead specified the use of a single adder which would add a fixed amount to the unit price for all customers. Their reasoning was that this would preserve the locational signals. In general it gives the opposite results to Ramsey pricing, since, assuming that customers at higher voltage levels have a higher elasticity than those at lower voltage levels, then under Ramsey pricing it is the 132kV customers which benefit most, whereas the single adder requires the 132kV customers to in effect pay for the historic costs of the 33kV network as well as for the 132kV network.

A third approach is to consider each voltage level to be a separate company or cost centre. Each voltage level then has a target allowed revenue which includes recovering depreciation and return on capital and current and deficit pension costs. This avoids the cross-subsidy inherent in both Ramsey pricing and the single adder by removing the vertical integration. OFGEM recognise this to some degree in that the transmission system is not asked to subsidise the distribution system and the EHV customers are not asked to subsidise the HV and LV customers. This method was originally selected for FCP. Despite criticism by OFGEM on the grounds that the locational charges would be neutered by the different adders at each voltage level, this has not been supported by any evidence that customers are likely to connect at anything other than the appropriate voltage level.

The present proposals introduce a further method based on the notional use of assets by tracing the flow in an intact system. For LRIC this is similar to the way that the reinforcement costs are charged since these depend primarily upon the path used in the intact flow and could be considered a fair way of allocating residual allowed revenue.

It could be argued that this is also a fair way to allocate residual allowed revenue for FCP. However, FCP aims to preserve the locational signals across a voltage level. Applying notional paths would distort the locational element, in effect making each Network Group a cost centre, rather than each voltage level. It also requires considerable more work, not necessarily an undue burden for the computer, but introduces an unnecessary level of complexity whilst at the same time diminishing the effectiveness of the method in terms of its original objectives.

Both methods have drawbacks. For example, the voltage level adder currently charges sites connected to a GSP the voltage level adder for the 132kV network, whereas they only use a very limited proportion of the 132kV network assets (switchgear etc). On the other hand, the notional path can set very high charges for customers remote from the voltage level source substation, even though there is no need to reinforce the intervening network. The proposed 'cap and collar' is intended to limit extreme cases.

The present proposals suggest that 20% of the residual allowed revenue should be recovered in the form of a single adder. The logic of this is unclear. There may well be some costs where this is a valid treatment. The text suggests pension costs. However, both current and deficit pension costs arise from employee costs. Most employee costs should be spread over the different voltage levels and it would seem inequitable for 132kV customers to pay for employee costs at 33kV when they don't use the 33kVnetwork.

Application of a single adder in conjunction with the voltage level adder would significantly increase the charges to customers connected directly at a GSP and lead to a double whammy. In effect, the 132kV network voltage level adder (or in Scotland, the 33kV network voltage level adder) already acts as single adder. If a single adder were to be applied in this case then it would probably be necessary to exempt customers directly connected at a GSP from the 132kV network adder.

However, since the notional path would be small for customers connected at a GSP, it could well be acceptable to apply a single adder in conjunction with notional path charges since this would set a base cost for such customers.

The use of the fixed adder for generation scaling is acceptable as generation is likely to supply adjacent substations at the same voltage level or that immediately above. As such a hierarchy of voltage levels is not relevant. A more detailed analysis would involve examining individual locations and would not seem to be warranted.

Conclusions

The conclusions are based on a consideration of the principles involved without any detailed evaluation of the implementation or of the spreadsheet working.

A fundamental question which has yet to be answered is whether the network modelling used by both methodologies actually captures the substantial investment believed to be required for the distribution network. This is particularly relevant to new sources of generation.

The LRIC approach only gives very weak signals regarding potential reinforcement costs due to capping. The use of notional paths will usually mask and dominate these signals.

However, overall LRIC should give provide 'fair' and justifiable charges in the sense that a reasonable method has been followed to allocate costs.

FCP gives stronger signals regarding potential reinforcement costs. However, these are likely to be masked when a notional path is applied for scaling.

Whilst it is desirable to use a common approach where possible for LRIC and FCP, it is important that the method of scaling fits the particular methodology. Thus LRIC applies nodal charging. The notional path method of scaling is also nodal. Because the notional path can be very short, the use of a single adder ensures that all customers bear some of the scaling charges.

FCP derives charges on a Network Group basis. Here a nodal notional path approach is not consistent whilst the voltage level adder preserves the signals of the reinforcement charges. The further application of a single adder can introduce too great a level of charges for customers connected at the transmission interface as they already will be charged for the network voltage level adder at their voltage level, which acts in effect as a single adder.

FCP combined with the voltage level adder should also set 'fair' and justifiable charges.

The original objective of transparency no longer features and is not likely to be met. To match the detailed description of the methodologies it is important that the requisite data should be publically available so that independent checks can be carried out.

Part 2

This gives responses to the specific questions asked by OFGEM in the consultation.

Chapter 2 - Overview

Question 2.1: *What are your views on the key issues with the methodology we have highlighted? Are there any other issues or concerns with the methodology as a whole that we should consider?*

Views on the methodology as a whole have been set out in Part 1 of this response. The DNOs' proposals envisage that OFGEM will enforce the charging of pre 2005 generators. If this should not be the case then only minor changes are required to the proposal.

There are issues on generation charges where high charges can be set if the present level of embedded generation matches the capacity of the network. This is greatly exacerbated if P2/6 (not actually applicable to generation) rules are applied as proposed. The escape clause is that such generators could enter a GSM agreement to limit or cease generation under fault conditions or when the capacity would otherwise be exceeded. Hence it is vital (see Question 6.2) that the rights of generators to enter such agreements under acceptable terms are guaranteed.

Question 2.2: *Should we approve the methodology, do you agree with our proposal to implement it in full from 1 April 2012? If not, why is phasing-in charges or delaying implementation appropriate?*

It should be possible, subject to minor changes, to approve the methodology from April 2012. There appears to be no substantial advantage in phasing-in charges or delaying implementation unless critical issues arise during the consultation (likely to be based on responses from customers or their representatives). The ability to amend the methodology via DCUSA offers a route for problems to be remedied in the future.

Chapter 3 – Charging proposals for demand customers

Question 3.1: *Do you agree with our assessment that the approach for the revenue target is reasonable?*

Yes, the proposed method of splitting the allowed revenue between EDCM and CDCM is reasonable.

Question 3.2: *Do you think the principle the maximum import capacity is a cost driver at the voltage of connection is reasonable for charging purposes?*

Yes. In practise both peak capacity and maximum import capacity may be important at all levels as the time of peak capacity on individual assets may vary. The simple rule of using the maximum import capacity at the voltage of connection and the peak capacity at higher voltage levels is a reasonable compromise. The diversity at higher voltage levels is very substantially less than that for the example for LV quoted by OFGEM.

Question 3.3: *Do you agree with our view that reactive power flows should be incorporated as part of the capacity that attracts indirect costs and 20 per cent of the residual?*

Yes. This would seem to be more consistent.

Question 3.4: *Is it appropriate to consider the specific assets the customer uses for the calculation of the customer's charge, or would it be more appropriate to consider only the voltage levels the customer uses for the calculation of its charges?*

Two arguments for considering only the voltage levels used by customers are: Firstly that assets are sized to accommodate flows under contingency conditions and for meshed networks the flow pattern is different from that under intact flow (used in the calculation of NUFs). Secondly, the charges arising from consideration of specific assets can nullify the message given by the reinforcement charges. FCP bases the reinforcement charges on the contingency flows but recognises that it is difficult to assign the reinforcement costs directly to individual customers and therefore spreads them over the Network Group. Thus for FCP it would be more consistent to consider only the voltage levels. However, the arguments are not so strong for LRIC since the reinforcement charges are based on the intact flow.

Question 3.5: *Do you think that the 'spare capacity' issue we identify should be addressed?*

It only needs to be addressed if it evidently causes significant issues for customers. One of the problems of using site specific charging is that there is no 'correct' way of allocating costs between customers. Some assets may be oversized, maybe because a reinforcement has taken place and it was considered worthwhile to build in spare capacity. To install a size larger cable may not make a huge difference to the cost but the cable may now appear to be lightly loaded. It would appear to be unreasonable for the customers which use that asset to only pay for a small portion of the cost. On the other hand there will be assets which in the intact system will be lightly loaded and their sizing is to support other customers in contingency conditions. Ideally part of the cost of these should be allocated to the Network Group or the voltage level, since there would appear to be no reason for their cost to be picked up by higher voltage levels. However, this would add complexity to the model and it is likely that the cap will prevent excessive charges.

Question 3.6: *Do you think notional asset values should take into account assets below the customer's voltage of connection?*

In general this issue will not arise. However, there are 33kV networks which use an intermediate 11kV network to draw power from another 33kV network or from a 132/11kV transformer.

Question 3.7: *Are there any other demand specific issues that you think we should consider as part of our decision?*

It should be queried as to whether pension costs should be allocated to the fixed adder. Pension costs relate to staff cost spread across the various voltage levels and yet higher voltage levels do not use the lower voltage levels. It is noticeable that in general it is only the 132kV customers which on average face increased charges and these are the customers in effect penalised by the fixed adder.

In general it would seem unwise to introduce new issues unless these have a material effect in causing unjustifiable charges for EHV customers.

Chapter 4 – Charging proposals for generation customers

Question 4.1: *Do you agree with our proposal to modify the generation revenue target in order to avoid double charging for operations and maintenance costs on sole use assets? This issue aside, do you agree with our view that the approach to calculating a generation revenue target is reasonable?*

Yes, although the approach could be deemed arbitrary, it is based on accepted practise. The long run approach of treating demand and generation in a fully integrated fashion is a very complex task.

Question 4.2: *Do you agree with our assessment that the approach to scaling is reasonable?*

Yes, taking into account paragraph 361 of the proposal that 'If the adder is negative it is only applied to each generation tariff to the extent that keeps the FCP/LRIC export capacity charge non-negative'.

Question 4.3: *Do you think it is appropriate for only units exported by non-intermittent generators during the super-red time band to be eligible for credits?*

Yes, but special arrangements may be needed within Generation Management agreements to cover stand-by generators. Normally the generation costs of such generators are high and they may only be used in certain exceptional demand or contingencies conditions. As such they could receive no benefit but would avoid the need for reinforcement.

Question 4.4: *Do you agree with our proposal that intermittent DG should be eligible for credits as they are deemed to provide network benefits under ER P2/6? If they do become eligible for credits, should the credits only relate to units exported during the super-red time band or is a single credit rate to all units exported more appropriate?*

It is not clear that intermittent generation does bring about network benefits as many of the intermittent generators in the same area may be wind driven and subject to the same weather conditions. However, if planning engineers do take account of intermittent generation in deciding on reinforcement, then it would be appropriate to provide a corresponding benefit. The benefit should be based on units exported during the super-red time band as this determines the need to reinforce.

Question 4.5: *On import charges for generation dominated mixed import-export: Do you agree with our suggested alternative to using the collar of the network use factor for the calculation of the import tariff? Do you think that the methodology is appropriate for demand customers connected to generation dominated assets?*

The use of the collar would seem to be simple and satisfactory. The generator is not paying a network use factor for export. It is likely that the generator will have already contributed to a portion of the cost of the assets via connection charges. However, much of the network will have already been in existence to supply demand. Hence applying the collar to import would seem to be reasonable. As more generation dominated networks appear, then it may be necessary to grade networks and consider NUFs for demand and generation so as to put them both on the same basis. However, this would seem to be unnecessarily complex at this stage in the development of EDCM and should be based on a study of actual situations.

Question 4.6: *Are there any other generation specific issues that you think we should consider as part of our decision?*

As embedded generation becomes more widespread, it will be necessary to ensure that import and export are treated equally along with generation supplied from the transmission network. The current models are geared to a demand driven situation. Note also that in the derivation of LAFs the same assumption is made that the energy is supplied from the transmission system. In a more general model each GSP is simply another embedded generator. The present model does not capture this situation.

Chapter 5 – Charging proposals for LDNOs

No views on this chapter

Question 5.1: *Do you agree when calculating LDNO charges that DNO costs upstream and downstream of the point of connection should be considered?*

Question 5.2: *Do you think that DNOs should provide LDNOs with a discount on all non-asset based charges?*

Question 5.3: *Do you think that varying LDNO discounts only with the point of connection will better achieve a balance between reflecting upstream and downstream costs?*

Question 5.4: *Do you agree that it may be appropriate in some circumstances for the DNO to pay LDNOs use of system credits?*

Chapter 6 – Common issues

Question 6.1: *Do you think sole use assets should attract scaling 'costs' to the same extent as shared assets? Does the charging rate on sole use assets seem reasonable given the nature of these assets?*

A large part of the scaling arises from that part of the allowed revenue which covers interest payments and return on capital, largely related to historic capital expenditure on the network. There is no reason that fully paid up sole assets should fund this. EDCM does not deal explicitly with replacement costs; neither is it clear whether users pre-paid for replacement in their initial payments. It would seem more reasonable that the 20% of the scaling not related to asset costs was charged to sole use assets rather than the 80% suggested by OFGEM.

Question 6.2: *Do you agree with our view that the arrangements for demand and generation side management agreements are appropriate? Do you think such agreements should be available to all customers?*

The reduction in charges in return for restricting demand or generation does not seem to be market driven. Consider an asset reaching its full capacity of 100MVA and requiring a reinforcement costing £1m unless demand is reduced by 2MVA. The annual benefit of deferring reinforcement is ~£50k. The capped LRIC charge is ~£500k/MVA. Thus an EDCM customer reducing demand by 2MVA will only receive a benefit of £1k. It is therefore well worthwhile for the DNO to offer a much higher benefit. However, once one customer has agreed, there is no benefit to the DNO in offering a similar rate to other customers. The proposal as it stands could be made available to all customers, but it may not be of great interest to them. This aspect needs a major rethink. Potentially DSM and GSM agreements are likely to be far more effective in reducing the need for capital investment than the locational charges introduced by EDCM.

Question 6.3: *Do you agree with our assessment that an explicit reactive power charge is not appropriate?*

Yes, a reactive power charge is not appropriate when charges are levied per kVA.

Question 6.4: *On the proposal for sense checking branch incremental costs in LRIC: Do you agree with our view that positive cost recovery (i.e. charges) and negative cost recovery (i.e. credits) should be considered separately? Do you consider that recovery from demand customers and recovery from generation customers should be considered separately?*

No. The proposed LRIC capping is very severe and weakens the intended message. It would seem appropriate that users of a particular branch should pay for the branch reinforcement charges and for credits to generators which delay the need for reinforcement.

Question 6.4: *Do you think the EDCM should include a mechanism to mitigate the potential volatility from network use factors? We welcome views on measures to mitigate volatility and help customers manage volatility.*

There is no evidence at present that volatility of NUFs (other than as a direct consequence of the actions of the particular customer) is significant. Further study would be useful before coming to any decision on rolling averages.