Mathematical & Computer Modelling

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Rachel Fletcher
OFGEM

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Dear Rachel,

Consultation and impact assessment on Scottish Power's proposed modification to their DUoS charging methodology: Implementation of the FCP (G3) approach. Consultation of 17th.June 2008, OFGEM ref: 86/08

Please find attached a response to your consultation document regarding SP's proposal on UoS charges for their Manweb and SP networks. As you will be aware I have been providing consultancy to Scottish & Southern Energy, part of the G3 group, but I would like to stress that the views expressed are my own and may well not be shared by SSE or the other members of G3.

Having been closely involved with the G3 team I feel it is important to point out that the development stemmed from the aim of meeting OFGEM's requirements for a forward looking methodology and has been driven by the need to provide new approaches to replace some of the demonstrably false methods previously proposed whilst at the same time including areas such as fault levels for embedded generation which have not to my knowledge been previously tackled. At all stages in developing both the tariff model and the FCP model for EHV, the methodology has been reviewed internally by all three companies within G3 and has since been analysed at some depth by external consultants not involved in the development. The proposed model takes these views into account.

I will be responding to your later consultation on the development of a common methodology but would like to note here that the G3 methodology has had to develop a common approach capable of implementation across 3 companies with 6 networks of very varying nature. As such it provides an appropriate basis for the common methodology and therefore in my view it would not be appropriate for OFGEM to veto the proposal by SP.

As you will appreciate there is considerable more technical information which could be provided on the responses outlined below. If you should wish clarification on any of the points raised, then please get in touch with me.

Yours sincerely

Robin Hodgkins

MCM response to OFGEM's consultation questions Annex 2 - Issues

Consultation Questions (taken from Annex 2 as Schedule 7 appears to be incomplete)

i) The use of Network group aggregation and different increments

- *The extent to which SP's approach to EHV demand charging is an acceptable trade off between cost reflectivity and stability.*
- *The extent to which the use of network group aggregation and separate increments are equitable and capable of producing economic signals which can lead to more efficient use of the system.*
- *The appropriateness of the charge pricing function.*

Comment:

Increments:- OFGEM's Figure A4 in Schedule 2 illustrates a key point. The capacity of different network groups and plant covers a very wide range. Thus the maximum demand of network groups in SP Manweb range from about 20 to 450 MVA and asset sizes from 7.5 MVA to 240 MVA (SHEPD have 33/11kV transformers analysed in FCP of only 0.5 MVA capacity). It is essential that increments are related to the levels of demand. FCP uses the 1% increment to estimate the years to reinforcement. Note that not only are current estimates of demand subject to weather correction and growth rates are not precise, but both investment planning and the annual variation in demand between summer and winter give rise to an annual cycle. So the aim is to identify in which year reinforcement would be required. Therefore, although a smaller percentage increment could be used, this is regarded as unnecessary (additionally the FCP algorithm is expressed in analytic form which doesn't depend, as the Bath LRIC, upon comparing potentially small differences between reinforcement times caused by small increments in demand). Note also that the 15% upper increment is not part of the methodology as such and is subject to review to match forecast growth rates at the time of setting charges.

Nodal versus Network Group charges:- Implementing nodal charges is superficially attractive (and in the long run may be feasible). However, there are a number of problems to which no solution has yet been demonstrated. A proper analysis requires the sensitivity analysis to be performed for each contingency condition. OFGEM's Figure A.8 of Schedule 5 doesn't give the methodology used to determine the nodal prices. EDF in their recent proposal base their nodal analysis on a sensitivity analysis carried out under normal operation. This is incorrect and gives erroneous results for some very simple configurations. It has not been shown that the results are preferable to averaging. It also introduces considerable additional work, complexity, and computational analysis. The full analysis of each contingency would almost certainly lead to considerable additional volatility and an order of magnitude increase in complexity. It must be queried whether it would be possible to validate such an analysis on anything other than simple test cases? G3 have therefore taken the view that using network groups provides a substantial variation in locational signals. It is accepted that this inevitably reduces the range of prices compared with a nodal analysis. However, this is regarded as preferable to basing the sensitivity analysis on normal load flows which could lead to unwarranted variation between nodes.

Economic grounds:- No economic basis is claimed for the empirical formulation of FCP. However, no economic grounds have been demonstrated for any alternative methodology. It is not known what pricing signal would be required to cause customers to modify demand to lead to a more efficient use of the system (note that the EHV customers, which alone are subject to the locational signals, are responsible for less than 15% of the demand on the EHV system). In so far as OFGEM have suggested that there may be an economic basis for LRIC methods, then the SP Appendix 4 applies LRIC methods to derive the LRIC Corrected algorithm which gives the same functional form as FCP. Hence any such economic basis would extend to FCP.

ii) The use of a test size generator and standard probability in EHV /HV generation charges

- *We ask for views on the extent to which the use of the test size generator represents an appropriate trade off between a forward looking, cost reflective methodology and a methodology which produces predictable, stable prices.*

- *We ask respondents to consider the fact that EHV demand growth is also likely to be lumpy. Respondents may also wish to consider the anticipated growth of distributed generation which is likely to flatten any 'lumpy' connection of generation.*

Comment:

Symmetry:- A key point is that there is considerable asymmetry between generation and demand. At present some 90% of demand is fed from the transmission network. Even if the current projection that new generation capacity over the next 10 years will match 30% of current demand is fulfilled, there will still be considerable imbalance, especially given the low P2/6 factors of wind energy. This means that new generation say at HV which might require switchgear or transformer reinforcement at the EHV/HV interface will be offset at the EHV level by demand. Thus reinforcements at the higher level will not be required. The increase in generation at EHV level is therefore appropriately modelled by capturing the characteristics of EHV generators. In contrast, increases in demand at HV will in general contribute to reinforcement requirements at all higher voltage levels. Thus the total increase in demand which requires reinforcement of the EHV network is composed of both the increases in EHV demand and the increases at HV and LV. If demand increases at the same percentage rate for all voltage levels then the EHV new demand is only of the order of 10 to 15% of the total increase in demand (probably less as large industries decline whilst commercial and domestic loads grow). Hence the FCP model for demand assumes that demand increases at an annual rate rather the setting charge rates based on the size of large EHV demand customers. A similar asymmetry applies to the choice of the Voltage Fixed Adder for demand but a single Fixed Adder for generation.

The ‘lumpiness’ of assumed generation reflects that actually experienced. If the lumpiness reduces at a particular voltage level then this will be reflected in the ‘test size’ at that voltage level. As discussed, increases of smaller size at lower voltage levels or a general increase in say micro-generation do not affect the reinforcement calculations.

iii) Varying the size of the test size generator

- *We welcome views on the extent to which it is appropriate for generator charges to go up when smaller generation connects to the network, and down when larger scale generation connects to the network.*

- *We also welcome views on whether the substantial differences between test size generators at different voltage levels may influence connection decisions i.e. a generator may connect at 33kV rather than 132kV.*

Comment:

Variation of generation charge rates with ‘test size’:- The smallish increase in generation charge rates as the ‘test size’ decreases reflects the fact that the cost of the reinforcement is not similarly reduced. The size and hence cost of reinforcement is geared to the particular voltage level and typical load flows. Overall, reinforcements would be required less often and new generation is less likely to trigger the need for reinforcement. Thus more generators would pay zero FCP charges since no reinforcement would be required but correspondingly when reinforcement would be required the cost is spread over a smaller amount of generation. OFGEM’s table A3, schedule 2, show the effect of substantial changes to the test size which are currently regarded as highly unlikely given that the ‘test size’ is determined from the distribution of all generators at a particular voltage level. Currently SHEPD, for example, has 61 generators at EHV with a ‘test size’ of 16.6 MVA based on the 85th.percentile. If it is assumed that in one year each new generator has a size of 2.17 MVA corresponding to the existing 15th.percentile then 15 new generators are forecast giving a substantial change to the statistical distribution size and defining a new ‘test size of 15 MVA. The effect is to increase the charge rate by about 10% with an offsetting increase in the number of network groups for which the charges are reduced to zero. This would be regarded as a somewhat extreme case and in general more gradual changes would be expected. An alternative would be to fix the 'test size'. However, given the small effects, it is regarded as more important to capture the changing nature of the size distribution especially as no quantitative forecasts of the likely size of new generation have been established.

The use of the different 'test sizes' at different voltage levels would in general encourage smaller generation to connect at lower voltage levels which is considered to be an appropriate message. Furthermore there are both engineering and connection charge issues with small generators connecting to say the 132kV.

iv) Revenue reconciliation

- *We welcome views on the extent to which SP's proposed scaling approach is appropriate both in terms of the 'COG' model and voltage level scaling.*

- *We also welcome views on whether the different scaling approaches to demand and generation are appropriate.*

Comment:

Voltage level scaling for demand:- The basis for this is set out in the proposal. The aim is to avoid distortion of reinforcement charges which vary between network groups and at the same time to avoid cross subsidies between voltage levels.

Different scaling approaches between demand and generation:- As described earlier demand and generation are not symmetric. Therefore whilst demand incurs charges for higher voltage levels, this is not applicable to generation. The need for scaling arises largely from the depreciation and rate of return charged on investments not recovered elsewhere. Most past investment was incurred to meet the needs of demand customers and therefore can be approximately apportioned according to the MEAV value minus that paid for by customers for each voltage level. However, it has not been possible to carry out the same assessment for generation. The allowed revenue for generation is determined by OFGEM per kVA of generation and therefore is appropriately passed through via a fixed adder.

v) Use of historic RRP data in HV/LV charging

- *We welcome views on the extent to which the use of historical RRP data represents an appropriate trade off between cost reflectivity and simplicity, and whether this approach is transparent given that RRP data is not published.*

- *We also invite views on whether a backward looking average technique is appropriate given the presence of developed forward looking models, particularly for the calculation of HV and L V reinforcement costs.*

Comment:

Use of historical RRP data:- A key factor is that locational charges are not applied at HV and LV and therefore it is the average costs that are sought. It would be a matter of concern if alternative models for estimating the reinforcement costs did not, at least approximately, match recorded reinforcement expenditure as the basis of the models would need to be questioned. Such models, if verified against actual costs could be useful if locational charges were to be applied in situations where types of network vary between locations (for example, urban and rural). However, there is no proposal at present to consider such variations. The other situation when some modification could be required is if the level of reinforcement was forecast to change rapidly. However, this would be best accommodated by say doubling the cost if the rate of increase in HV/LV demand doubled rather than introducing extraneous models. Since rates of increase in demand do vary, then the smoothing in expenditure by including more than one previous year needs to be limited so as not to lose current trends *vi) Coincidence with system peak*

- *We welcome views on the extent to which SP's proposal incorporates customer coincidence to peak demand and incentivises higher utilisation of the network based on time of day and seasonal influences.*

- *We also welcome views on the extent to which SP are correct in using four time periods for HV/LV customers while only one time period for EHV customers.*

Comment:

Coincidence factors:- These are used for HV and LV within the Tariff model to set charge rates taking into account time of day and seasonal factors. They encourage both customers and suppliers to shift demand away from peak periods to periods of low demand.

EHV Time Bands:-

The G3 approach is designed to give appropriate cost signals taking into account existing contractual arrangements and billing system implications. EHV customers agree with the DNO the capacity arrangements for the connection which is incorporated in the connection agreement. This capacity is normally a single figure in kVA and is made available on an unrestricted basis for the customer throughout the year. The capacity is also the basis of charging the site-specific DUoS charge and therefore the customer is incentivised to maximise utilisation and request only the capacity really required. Furthermore, a single maximum capacity will give a sharp cost /incentive signal to the customer to manage demand and capacity in the most efficient manner. The adoption of multiple time banded capacity charges would require the customer to agree significant revisions to the connection agreement, the DNOs to put in place demand monitoring processes to ensure compliance with the connection agreement and changes to the DNO's DUoS billing system. The proposed approach is believed to be appropriate and proportionate.

vii) Different approaches between demand and generation

- *We welcome views on table 1 and the extent to which there are substantive differences between demand and generation which warrant an asymmetric approach.*

- *Do respondents consider that SP's approach is appropriate?*

Comment:

Asymmetry between demand and generation:- see earlier comments under (ii). There is a major asymmetry which needs to be captured by different charging models.

SP's approach:- The G3 approach was developed after considering a number of other approaches and is regarded as suitable to meet the objectives set out. More complex models could be introduced but are not regarded as giving sufficient additional benefit to warrant the extra complexity and delays in development. The approach has been modified to take account of feedback from earlier consultations, from OFGEM, and from external consultants. Note that so far no DNOs outside G3 have yet taken into account fault levels which are the main factor in the forward looking cost component of generation charging.

viii) Use of a ten year recovery period

- *We welcome views as to whether it is appropriate to only consider demand reinforcements which will occur within a ten year period. Does this represent a practical trade off between a forward looking model and a simplistic approach?*

- *We welcome views on whether it is appropriate to only assess the benefit generation can have in deferring demand reinforcements due within ten years. Does this adequately reflect the benefits which generation can provide to the distribution network?*

- *We welcome views on the potential for the use of a ten year period to lead to tariff jumps as lumpy demand connection brings forward reinforcement by a number of years.*

Comment:

Use of 10 year Cost Recovery Period:- The reasons for this are set out in the proposal. The objective is to encourage customers to locate where reinforcement would not be required within the 10 year period. Determining charge rates by unwarranted extrapolation of growth rates to 30 years or more is regarded as counter productive, especially given the uncertainty attached to growth forecasts. Analysis of historic data shows substantial variation in the average long term growth rates and evidence that higher than average growth rates tend to tail off as development in a particular area reaches saturation. The proposed method could also be interpreted as simply setting the forecast growth rate beyond 10 years as zero, which may well be the best current estimate. An additional reason is the difficulty of modelling engineering reinforcements well into the future when earlier reinforcements impact on later reinforcements.

Overall benefits of generation:- The model looks at reinforcement benefits at the EHV level by Network Group and at HV and LV by averaging over the whole network. If more general encouragement is to be given to generation, then this would need to be defined by government or OFGEM.

Tariff jumps:- These could arise in the locational charges from two causes: First, when reinforcement occurs, either because of steady growth in demand or because of lumpy new demand or generation. This is a feature of forward looking cost methods as the reinforcement creates spare capacity and changes the cost message. Secondly, when either gradual increase or lumpy new demand or generation brings the time to reinforcement within the 10 year Cost Recovery Period. The step change from the zero reinforcement charge at this point is a useful signal to users that further increases will lead to higher charges as spare capacity is reaching the capacity limits.

ix) Recognition of intermittent generation

- *We welcome views on the extent to which SP are correct in using F factors to calculate the benefit LV generation can provide to the network.*

Comment:

Use of F-Factors:- A main objective has been to match the charging methodology to agreed industry practice. It is seen as undesirable to set up separate methodologies which potentially conflict with agreed rules. Thus P2/6, with other agreed engineering guidelines, defines the methodology by which engineering reinforcements are evaluated. In some cases there is a certain latitude in interpretation. For example, the effects of both demand and generation depend upon their location on the network. However, for new demand and generation the specific location is not known. If new generation, for example, is situated at the source busbars then there will be no benefit in reducing the need for downstream circuit reinforcement. However, if generation is downstream, then it may reduce the need for network reinforcement. In general the procedures set out in Appendix 2 of the proposal have been framed to give the most favourable benefits to new generation within the industry rules. However, LV generation on a radial feeder provides no benefit to LV as faults cause loss of the whole feeder. Current P2/6 rules provide no benefit at higher voltage levels and reinforcement plans therefore take no account of LV generation. If P2/6 rules are amended, then this would be taken into account in the charging methodology. In compensation, no generation reinforcement costs are included for LV generators.

Note that P2/6 provides general rules for assigning F Factors based on the type and number of units. However, a particular generator may, subject to agreement with the DNO, be assigned a higher F Factor should there be sufficient evidence to support this.

x) Reactive power charging

- *We welcome views on the extent to which SP's proposal encourages EHV customers to make the most of their power factor as well as on their changes to HV /LV reactive power charging.*

Comment:

Reactive power:- Networks need to be sized to carry the level of current at their maximum flows. The magnitude of the current is defined by the kVA rather than the kW. Very poor power factors could also affect the ability of switches to operate effectively if there is a large phase angle between voltage and current. However, any single customer’s poor power factor will be largely diluted by those of other users. Basing the charge rate for EHV customers on the kVA maximum demand value takes into account both active and reactive components of power and encourages customers to minimise their reactive power component. HV and LV half-hourly metered customers are not charged solely on maximum demand and therefore a different method is used. This allows for the condition that NHH metered customers, charged on a kWh basis, are assumed to have a power factor of 0.95. Thus the method proposed charges customers the marginal cost for the periods when their power factor is worse than 0.95.