Mathematical & Computer Modelling

W. R. Hodgkins MA, CMath, FIMA, MIMIS
15 Cotebrook Drive, Upton, Chester CH2 1RA
Tel: 01244 383038 email: WRHodgkins@aol.com
Vat.Reg.No: 742 3574 34

Rachel Fletcher
OFGEM

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Dear Rachel,

Electricity distribution structure of charges project: decision of a common methodology and consultation on governance arrangements Ref:104/08

Attached are some notes in reply to OFGEM's recent consultation. 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. I am assuming that each of the G3 companies will be replying individually and dealing more specifically with the detailed questions that you raise.

I would emphasise that the G3 approach has been developed in the light of the initial WPD approach to specifically correct some evident flaws and to remedy the perceived weaknesses. G3 have sought to develop a robust method which is capable of being implemented and validated in different companies with different computer software. It has built on the common development of all the DNO's in the COG model for setting tariffs. As such it offers the best basis for implementing a common approach across all DNOs.

Rather than work through OFGEM's specific questions, I have attempted to deal with some of the major issues which differentiate the various approaches. Unfortunately there seem to be a number of misconceptions which cloud the judgement of the various proposals. Some of these are basic and quite deep rooted and seem to inhibit an objective examination of the merits of the various approaches. I hope this feedback is useful in clarifying these issues, or at least indicating where rethinking is required.

One final point, I do think that before finalising any outline methodology it is advisable to review whether the methodology would help to achieve the desirable aims, not of imposing a particular system of charging but of encouraging new generation.

Yours sincerely

Robin Hodgkins

Mathematical & Computer Modelling - August 2008
Response to OFGEM Consultation:

Electricity distribution structure of charges project: decision of a common methodology and consultation on governance arrangements Ref:104/08

Contents:

1. Economic Arguments

Both OFGEM and other parties use the terms ‘economic’, ‘economic efficiency’, ‘economic basis’, etc in a rather shotgun manner to support or condemn various approaches. I am not aware of any demonstration that the principles of the Bath LRIC have any economic basis. Neither is any economic basis claimed for the empirical derivation of FCP.

However, the ‘Pure incremental method’ described at the start of Section 6 could possibly claim an economic basis under certain circumstances. The requirements would seem to be that there is a spot market (annual if charges are set annually) in which there are a large number of customers which have alternative supplies of energy so that as charge rates rise, then some customers will choose alternative energy suppliers and as prices fall, then previous or new customers will return. This is clearly not the actual situation, since the locational EHV charge rate only applies to a limited number of EHV customers, maybe only one customer on a Network Group. There may be no flexibility regarding alternative energy supplies and if the price reflectivity is small, then high charge rates could result, leading to the complete loss of the single demand user or generator with no replacement when charge rates fall. Furthermore, the price reflectivity is likely to be unknown in practice. However, if the ideal market conditions prevail it would seem that the policy of applying zero charges whilst there is still spare capacity with subsequent charge rates then set according to the price reflectivity to restrain demand to the available capacity could be shown to be a local optimum by considering alternative polices with prices marginally different from the presumed optimum. However, I am not aware that this (weak) proof has actually been presented. (A ‘pure’ economic argument could indicate that negative charges should apply where required to increase demand to utilise all available capacity with the cost being recovered when the capacity is exhausted - but what happens if the capacity is never exhausted!).

The NPV approach replaces the economic approach of the Pure Incremental method by spreading the charges over an extended period according to changes in the NPV. There is no economic basis for this. It is a purely financial arrangement which uses the timing of NPV as a proxy for the real timing which would match the unknown optimum customer response. The argument against the Pure Incremental method is that customers need time to respond and sudden increases in charges at the point where surplus capacity is exhausted does not allow this. As such NPV may result in a better economic efficiency, but I have not seen any argument for this. Such an argument would require the modelling of customer behaviour and their economic performance.

If, however, an economic argument could be shown for the NPV approach, then, since FCP has the same functional form as the NPV based LRIC Corrected, the economic argument would apply to FCP.

2. Price Reflectivity

There appear to be two different aims propounded by OFGEM: First that FL LRIC should be the basis of the methodology as preferred by the EU regulators. Note, however, they don't specify a particular method of implementation and at that time there was no acceptable implementation in circumstances when 'capital indivisibility' needs to be taken into account. The second is that the price signals should be large enough to bring about the desired location or relocation of demand and generation customers to substantially reduce the need for network reinforcement. These can be mutually exclusive. The price signals necessary to change customers locational behaviour are not known. The Bath study, quoted several times by OFGEM, doesn't provide enough detail for the results to be replicated and parameters varied. However, it can be summarised as stating that if there is sufficient new generation to match the increase in demand and that generation always locates at the location with the most attractive price signal, then, provided that the locations are correctly signalled, no demand reinforcement would be required. As such the Bath study shows substantial savings in reinforcement costs. However, the study provides, and can provide, no information on the magnitude of the price signals which would be required to actually bring about such changes. Feedback from generators and their representatives and general consideration of the nature and location of many renewable resources, suggests that very large price signals could be required.

However, the price signals from a FL LRIC approach are based on the cost of reinforcement without regard to customer response. Over a long enough period the revenue should at least roughly match the actual expenditure. If customers are prepared to pay the additional cost of locating where reinforcement would be required, then this is the economic choice of the customer and the distribution monopoly should not distort the price signals to deter them.

OFGEM have sometimes criticised various methods on the grounds that the price signals are not large enough. Very low or high charge rates may well indicate flaws in the methodology. However, in many cases OFGEM have based comparisons on the Bath LRIC at 1% growth rate where flaws in the methodology give rise to excessive charge rates. At lower growth rates even higher charge rates would arise which as Reckon have pointed out could provide a valid basis for a legal challenge.

3. Incremental v Average

A methodology declared to be 'incremental' seems to automatically deserve approbation, whilst introduction of the term 'average' seems to automatically incur disapprobation, without regard to an analysis of the methodology. However, in the situation when a small increment in demand would give rise to a substantial cost, then applying this rate to all existing demand results in grossly excessive charges. Therefore, in all the methods proposed, an averaging process is applied. This is the case in ICRP where the cost is in effect spread over the lifetime of the asset by applying an annuity factor. This is also the case with both the Bath LRIC and the LRIC Corrected methods where again an annuity factor is applied. Bath LRIC incorrectly bases the annuity on the lifetime whilst LRIC Corrected uses the cost recovery period. LRIC Alternative spreads the cost over the demand and doesn't require an annuity factor. However, despite using a different averaging process it results in the same functional form.

The lack of a clear economic argument for LRIC plus the evident flaws in methodology and outcomes for the Bath LRIC implementation led G3 to propose the FCP empirical method which doesn't explicitly introduce either type of averaging but seeks an appropriate variation in charge rates with demand and growth rate, subject to the criterion that the cost of reinforcement is recovered within the cost recovery period. All three approaches, LRIC Corrected, LRIC Alternative, and FCP have the same functional form and similar charge rates depending on the choice of the cost recovery period. They are also consistent with ICRP, with low charge rates when reinforcement is distant, rising to a sensible multiple of ICRP as reinforcement approaches.

4. Forward Looking

The meaning of 'Forward Looking' is open to interpretation. However, it should never mean beyond the horizon. Crystal ball gazing does not provide an economic argument. There are two major areas of uncertainty plus an appraisal of the objectives of the process that need to be considered.

The LTDS of each DNO tabulates growth forecasts for 5 years ahead. These are intelligent assessments based on the observed level of growth with a degree of understanding of the possible causes. Confirmed or planned new demand is taken into account. The tabulated values for each substation, usually to an apparent accuracy of 0.1 MVA, may convey a misleading impression. An analysis of earlier forecasts for one DSA shows that over half of the entries correspond to zero, low, medium, or high growth rates corresponding in this case to 0, 0.8%, 1.6%, and 2.4% rates of growth. Other entries show that local plans have been considered. Thus one substation shows MVA values of 1.0, 2.0, 3.0, 3.2, and 3.3. It would be interesting to see how the ENW computer program extrapolates this for many years ahead. A general observation drawn from historic data is that growth rates well above the average do not normally persist for more than about two 5 year cycles before falling back towards the normal growth rate. The average long term growth rates are also observed to change substantially. At this particular time with large increases in energy prices backed by government support for energy saving, it would appear that recent (smallish) growth rates are likely to diminish further. Thus unthinking extrapolation of even the average growth rate beyond a period of a limited number of years is likely to prove false.

FCP tackles this problem by limiting the analysis to within a time horizon of 10 years (maybe on the above arguments, this should be shorter). An alternative would be to assign a probability to future growth forecasts which would diminish with time, say halving over a 10 year period. Another option would be to extend the forecasts in a more complex way by causing individual substation forecasts to tend towards the mean growth rate, with the network mean growth rate being based on some government average forecast for the longer term future (of course this could be zero or even negative). The point is that extrapolation is likely to give misleading answers and result in wasteful economic decisions. Applying varying growth rates, perhaps with an attached probability, introduces an additional level of complexity in the analysis which unless there is a strong conviction that long term growth rates can be forecast, would seem to provide no significant benefit, especially when the remaining two issues are considered.

Even when growth rates are stable over long periods into the future, the resulting growth in the network is not necessarily stable. The first reinforcement will often be reasonably clear. However, in some cases growth will take place marginally faster elsewhere so as to require a different reinforcement. Further down the chain subsequent reinforcements are then affected by the choice of the first reinforcement, with changes to the network becoming increasingly variable depending on quite small changes in growth rates. The effect is somewhat reduced in the FCP

Network Group approach since all the reinforcements within the Network Group are averaged over all demand. For the Nodal Analysis approach there could be considerable volatility in prices between nodes. In some cases the automated computer analysis could indicate several reinforcements for the same Network Group in one year or within a few adjacent years. In practice these would often be replaced by a single integrated scheme at substantially lower cost. However, if such a large scheme were to be required within the next 10 year period, then planning engineers would usually have recognised the problem and would be preparing outline schemes, thus enabling inaccurate projections of individual reinforcements and costs to be detected. It is important if the methodology is not to fall into disrepute that projected costs at least approximately match planned costs and allowed revenue for such reinforcements. Again, it is generally more appropriate for integrated reinforcement schemes to be charged across the Network Group rather than costs to be allocated nodally.

The third issue concerns the objectives of the process. Besides falling into line with the EU regulators, a stated aim is to provide appropriate signals to encourage both demand users and generators to make the maximum use of the existing network and minimise the requirements for future investment. The 'Pure Incremental' approach simply says that if there is spare capacity, then use it, but it doesn't signal to generators that the capacity for further demand is being exhausted until it is too late to respond. It is analogous to judging driving speed along a road. It depends both upon braking distance and likelihood of something appearing that would require a change in driving behaviour. The ability to see several miles ahead is not required. Optimum behaviour is based upon the time scale over which it needs to be adjusted. If there is ample network capacity for the next 10 years, then should this change in the next year, there will be a further 10 years for customers to change their plans.

Finally it should be noted that only taking into account reinforcements within a limited period ahead gives sharper and more focussed messages since the reinforcement cost is unchanged but recovered over the shorter period.

5. Symmetry

The general tenor of the OFGEM commentary is that symmetry is good, asymmetry is bad. It is necessary to distinguish clearly between situations where symmetry applies and situations where there are substantial differences arising from actual physical or engineering behaviour or large imbalances between the level of demand and generation. The Bath LRIC algorithm and the equivalent FCP EHV demand algorithm assume a model with an existing level of demand and a growth rate. Furthermore, growth in demand at lower voltage levels results in increasing demand at higher voltage levels. Hence transformer and circuit reinforcements are largely determined by the general growth of new demand rather than by the incidence of new large EHV customers.

Generation can be regarded as offsetting the increase in demand and reducing the need for demand led reinforcement. The value of the generation depends upon the amount of generation that can be reliably assumed to be available at the times when the levels of demand are maximum. For planning purposes this is laid down by the P2/6 engineering standards. The G3 approach interprets these standards generously when evaluating generation benefits. This treatment, similar to that proposed by WPD and EDF, could be regarded as symmetric.

However, the largest reinforcement cost for generation is replacing switchgear to handle larger fault currents. Generation at lower voltage levels normally makes an insignificant contribution to fault levels at higher voltage levels due to the impedance of the intervening transformers and network. So it is discrete new generators at EHV level which determine the change in fault levels. The fault levels in this case cannot be offset by increased demand (indeed increased demand marginally increases fault levels). A third asymmetric factor is that it is necessary to consider the finite size of the new generators. Thus there is an inherent asymmetry and a different approach is required.

The G3 approach to generation charging has been designed to reflect these particular attributes. Note that no other DNOs have yet proposed any method for charging for fault levels and therefore it is misleading to describe FCP as asymmetric in contrast to the symmetric WPD and EDF approaches.

6. Incremental Methods - LRIC Corrected

Several approaches could be adopted to setting the demand charge rates. The ‘pure’ incremental approach sets a zero charge whenever the spare capacity is sufficient to accommodate the estimated increment in future demand. If the charge rate is continuously reset in time then this sets a zero charge until the spare capacity reduces to zero. If charge rates are set annually then a zero charge is set until the year is reached when there is insufficient capacity to accommodate that years estimated growth in demand.

Once the demand reaches capacity then charges are applied. In a monopoly situation a utility needs to recover the cost of the required reinforcement. The charge now set is that just sufficient to reduce the underlying growth in demand to the available capacity. As the underlying demand grows further, then the charge rate is correspondingly increased. The revenue is nominally invested at the discount rate and this process continues until such time as the value of the accumulated revenue is sufficient to pay for the required reinforcement.

This model assumes knowledge of the price reflectivity. Note that since new demand cannot be distinguished from existing demand, this is the average price reflectivity of all demand, not the much higher charge rate which would need to be set to discourage all new demand. In practice this price reflectivity could be very low as the EHV demand on some network groups may be only a small proportion, or even zero, of the total demand. Furthermore, the reinforcement charge rate is only a proportion of the total DUoS charge rate and changes in energy costs will interfere with the cost message. In principle if the price reflectivity is zero, then, assuming charges are set annually, the charge rate in the reinforcement year recovers all the reinforcement cost in that one year.

Not only could this give rise to very large charge rates, it fails to give advance notice of the impending need for reinforcement. This is an inevitable consequence of the ‘pure’ incremental approach when faced with ‘capital indivisibility’. However, an important aim of introducing an improved methodology is not only to encourage growth in demand to take place where it can be accommodated without further investment, but, perhaps more importantly, to encourage generation to locate where increases in demand would otherwise require reinforcement to take place. These factors indicate that some level of advance signalling is required.

In determining the time period over which advance signalling is appropriate several factors need to be taken into account. The LTDS produced by each DNO currently forecasts demand for 5 years ahead. Given the time required for potential generators to consider their options, draw up plans, gain planning permission, and implement the schemes, this is considered a somewhat inadequate time scale for future planning. On the other hand, forecasts in demand become increasingly inaccurate as they are extrapolated into the future (long term forecasts, assuming current energy savings measures are effective and embedded generation, particularly at LV grows as targeted, suggest an average zero growth in demand beyond about 10 years). Furthermore, whilst the initial reinforcement resulting from growth in demand can be forecast with some confidence, subsequent reinforcements depend quite sensitively upon the order and nature of earlier reinforcements (planning engineers may increase the magnitude of an earlier scheme to avoid the necessity of some future reinforcements). Therefore basing charge rates on forecast growth and reinforcements a long time into the future could introduce very substantial errors and consequent inefficient investment decisions. G3 have proposed a time period of 10 years as it is believed that this gives adequate time for planning without incurring too large errors in demand forecasts and reinforcement schemes.

There is no unique way of modifying the 'pure' incremental approach to set charge rates in advance of the reinforcement being required. The empirical approach simply selects an appropriate formula based on the reinforcement cost, utilisation and growth rate to match the desired behaviour. The method adopted here, LRIC Corrected, is to apply a financial approach based on Net Present Value which uses an accounting time scale as a proxy for the economic time scale which depends upon customer planning and response times and rates.

Let the growth rate of the demand, D kVA, be denoted by r per annum. Then, if C kVA is the capacity at which reinforcement is required, the demand at time t years prior to the capacity being reached is given by:

$$D(t) = C \exp(-r\, t) \text{ kVA}$$

The Present Value, PV, of reinforcing the asset, cost £A, at an annual discount rate of i is:

$$PV = £\, A \exp(-i\, t)$$

The effect of a small change in D at time t is given by:

$$\mathrm{d}(PV)/\mathrm{d}D = A\, \mathrm{d}(\exp(-i\, t))/\mathrm{d}D = A\, \mathrm{d}((D/C)^{i/r})/\mathrm{d}D = i\, (A/C)\, (D/C)^{i/r-1}/r \text{ £/kVA}$$

This is the analytical form[1] of the standard formula for the LRIC marginal cost of individual asset reinforcements. It can be expressed in terms of time rather than demand:

$$\mathrm{d}(PV)/\mathrm{d}D = i\, (A/C) \exp(-i\, t) \exp(r\, t)/r \text{ £/kVA}$$

Note that the units are £/kVA and in order to determine an annual rate an additional factor needs to be introduced. Applying an annuity factor based on the lifetime of the asset is incorrect, since such a value is based on the rental rate or mortgage rate assuming that constant payments can be collected over the lifetime of the asset. Here the payments are not constant and will only be paid over the cost recovery period from the time when the previous reinforcement was carried out until the time of the next reinforcement. The factor therefore needs to be based on the cost recovery period, not on the asset lifetime. Moreover, in keeping with the concept of NPV, it is more appropriate to use repayments which contribute equal amounts to the final total rather than equal instalments. Thus, denoting the cost recovery period by T years, the annuity factor is chosen to be:

$$\exp(-it)/T$$

Denoting the initial demand by D_0:

$$\begin{aligned} \textit{charge rate} &= i\, (A/C) \exp(-2i\, t) \exp(r\, t)/rT \\ &= i\, (A/C)\, (D/C)^{2i/r-1}/\mathrm{Log}(C/D_0) \quad \text{£/kVA p.a.} \end{aligned}$$

If the additional reinforcement is assumed to double the capacity then the initial demand can be taken to be half the capacity and the numerical value of the denominator gives a multiplying factor of 1.44.

[1] EDF investigate the effect of using increments of 1 MVA and 1 kVA. Here the increment is infinitesimal. Using large increments and time steps of one year causes some differences in the actual values but doesn't change the overall behaviour of the results.

7. LRIC Alternative - Derivation

Let the cost of reinforcement of an asset at the time of reinforcement be A (£). Denoting the annual discount rate by i p.a., then the Present Value of reinforcement required in time T (years) is given by:

$$PV = A \exp(-iT)$$

Assuming the demand D (kVA) is increasing at a rate r p.a. and the capacity of the asset is C (kVA) then:

$$D = C \exp(-rT) \quad \text{hence} \quad T = \mathrm{Ln}(C/D)/r \quad \text{and} \quad \exp(-iT) = (D/C)^{i/r}$$

Now the change in PV with D is given by:

$$\mathrm{d}(PV)/\mathrm{d}D = \mathrm{d}(PV)/\mathrm{d}T\ \mathrm{d}T/\mathrm{d}D = -iA \exp(-iT)\ (-1/rD) = (i/r)(A/C)(D/C)^{i/r-1} \text{ (£/kVA)}$$

Note that:

$$\int_0^C (i/r)(A/C)(D/C)^{i/r-1}\mathrm{d}D = A$$

and that this is true independently of T.

Now the annual increment in demand is rD (kVA p.a.). Therefore the charge rate per unit demand becomes:

$$i(A/C)(D/C)^{i/r-1} = i(A/C)\exp(-it)\exp(rt) \text{ (£/kVA p.a.)}$$

But the actual charge levied depends on the time t (years) prior to reinforcement and the above result therefore needs discounting by $\exp(-it)$. Thus the final charge rate becomes:

$$rate = i(A/C)(D/C)^{i/r-1}\exp(-it) = i(A/C) \exp(-2it)\exp(\mathrm{rt}) = i(A/C)(D/C)^{2i/r-1} \text{ £/kVA p.a.}$$

Note now that:

$$\int_0^\infty i(A/C)\exp(-2it)\exp(rt) \exp(it)\ C \exp(-rt)\ \mathrm{d}t = A$$

Thus the total cost recovered from an infinite time prior to reinforcement till the time of reinforcement, assuming the revenue is invested at the given interest rate, equals the asset reinforcement cost.

The preceding derivation gives the same functional form as that given by LRIC Corrected and by the empirical derivation of FCP. Here no choice of annuity factor is required. FCP normalizes the above functional form to recover all revenue over a fixed cost recovery period whilst LRIC Corrected bases the annuity period on the time for the demand to grow from half capacity to full capacity.

Neither the above formula nor LRIC Corrected take into account the probable error in extrapolating growth rates well into the future.

8. Nodal Analysis

The G3 FCP approach derives locational charges according to Network Groups. The aim is to follow as closely as possible the standard planning procedures followed within each company in determining network reinforcements. In general, because of the need to provide network security, reinforcements are provided to meet the demands of more than the customers immediately downstream of the reinforcement. In practise individual branch reinforcements will not be the outcome, but rather an integrated scheme which meets the needs of growth over the whole Network Group. Therefore apportioning costs between loads at individual nodes can introduce unwarranted differences in charge rates besides requiring substantial computation on the basis of often unsubstantiated assumptions.

However, both WPD and EDF have proposed using load flow analysis to derive individual nodal charge rates. In principle a full nodal analysis should be capable of identifying the effects of incremental changes in loads at each load point. However, this is not what EDF propose. The proposal states that the requirements for reinforcement are determined from the appropriate N-1 and N-2 contingency analysis using AC load flows based on average load growths for the network being analysed, but the sensitivity analysis is carried out only for the load flow under normal operating conditions. This would appear to nullify the potential advantages of the full nodal analysis. I am not aware of any studies which show that the results from this method are any better (in the sense of corresponding to the case where the sensitivity analysis is carried out for each contingency case) than treating all the loads as having the same sensitivity coefficients. Consider the following highly simplified case consisting of three identical branches with two identical loads supplied from supply points at either end of the line.

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S1 |-------------------- L1 --------------------- L2 ------------------| S2
           B1                        B2                  B3
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Under normal operating conditions the power flowing in Branch 1 is 2/3 L1 + 1/3 L2, the load in B2 is zero, and the load in B3 is 2/3 L2 +1/3L1. Under contingency 1, loss of either S1 or B1, the power in B2 is L1 and the power in B3 is L1 + L2. The other critical contingency condition is loss of S2 or B3 when the power in B1 is now L1 + L2 and the power in B2 is L2. It is easy to see that the sensitivity coefficients for both contingency conditions are the same for both load points. However, the sensitivity coefficients derived from the single normal load flow would assign a 2/3 sensitivity factor to L1 and a 1/3 sensitivity factor to L2 for contingency 1. To normalise the results EDF apply a security factor to each branch which reduces the effective capacity or rating by the ratio of the load in the contingency condition to that under normal load flow. The security factor for branches B1 and B3 is therefore 2. Thus the sensitivity factors are increased to 4/3 and 2/3. The total of 2 is the same as that derived from the true contingency analysis but that for the first node is twice that for the second node whereas the correct treatment would yield equal values of 1.

The security factor would be infinity for the worst contingency condition on B2 since there is zero power flow in B2 under the normal load flow. EDF state that when there is zero or near zero power flow in a branch under normal load flow, then the security factor is set to 1. It doesn't state the specific rule or rules are for deciding when a value is near zero. So for B2 the normalised load flow sensitivity factors would be +1/3 and -1/3. However, contingency 1 gives a power flow of L1 in B2 so the load flow sensitivity factor is only 1/3 of the correct value.

Adding a further branch and load point illustrates another problem met by the EDF approach.

S1 |-------------------- L1 --------------------- L2 ------------------ L3 -----------------| S2
B1 B2 B3 B4

The maximum loads in each branch in the worst contingency are as follows, assuming that all loads are of equal magnitude:

B1 & B4:	L1 + L2 + L3
B2:	L2 + L3
B3:	L1 + L2

The normal load flows and security factors in each branch are:

B1:	¾ L1 + ½ L2 + ¼ L3	2
B2:	½ L2 + ¼ L3 - ¼ L1	4
B3:	½ L2 + ¼ L1 - ¼ L3	4
B4:	¾ L3 + ½ L2 + ¼ L1	2

Thus the sensitivity factors can be written in array form as:

	normalised			true			average
	L1	L2	L3	L1	L2	L3	
B1:	1.5	1	0.5	1	1	1	1
B2:	-1	2	1	0	1	1	2/3
B3:	1	2	-1	1	1	0	2/3
B4:	0.5	1	1.5	1	1	1	1

Again the sum of the normalised sensitivity factors for each branch equals the sum for the true sensitivity factors but the variation between the nodes is unwarranted. In this case the feeder average values are closer to the true values than those derived from the normal load flow.

This case illustrates another issue in the modelling process. Some of the sensitivity coefficients from the normal load flow are negative. When loads are equal at each load point then from symmetry it can be seen that the power flowing from supply point S1 through branch B2 is equal to 0.5 L2. Increasing L1 draws more power from S2 through B2 thus reducing the power flowing in B2. It is not clear from the EDF description whether B2 is treated as a lightly loaded asset.

For a simple circuit with arbitrary positive loads and branch impedances it can be readily seen that the contingency loads will never decrease when a load increases and hence the true sensitivity factors are always positive. In principle this is valid for all true contingency conditions, since a negative sensitivity factor would imply that a larger power flow would pertain if one of the existing loads were to decrease and hence the true contingency condition has not been reached. Whether the standard contingency analysis considers all possible loading conditions rather than just maximum loads depends on each companies' implementation. EDF state "Additional anomalies can be caused when under contingency conditions the power flows in an asset reduce. This happens due to network configuration and/or power flow modelling accuracies. This has the effect of recording a security factor of slightly less than 1. In these circumstances it is proposed to collar security factors below 1 at 1 when they are used in the charging model." It is not clear that this is an accurate diagnosis of the phenomenon or a valid correction.

The above analysis is based on a DC linear load flow. AC load flows with more complex topologies can introduce recirculating flows which pose additional problems both in the volatility of the load flows and in deciding on a logic for deriving sensitivity factors. However, it has not been demonstrated that even for the DC load flow that sensitivity analysis based on the normal load flow gives robust results which would more closely approximate a true analysis than does the Network Group approach.

It is easy of course to produce examples where the Network Group approach doesn't capture the nodal variation that would result from a complete nodal analysis. However, the simpler approach would seem to be generally more applicable to supply point reinforcements and the SEPD analysis suggests that most required circuit reinforcements are part of the main ring or line linking two supply points.

The above only considers two very simple cases. A considerable amount of theoretical analysis and numerical validation remains to be done to establish the value of the normal load flow approach. However, although a full nodal analysis could be regarded as the ultimate objective, there are theoretical and practical issues still to be resolved. A full analysis would of course require substantial additional computation, could cause potential additional volatility in that it would have to handle competing contingency situations, and in terms of the amount of data processing required, render the validation of the results unmanageable.

It is therefore concluded that the results from the Network Group approach provide a robust method which can be implemented and validated within the OFGEM timescale. It has not been shown that the results from a nodal analysis based on normal load flows give numerically better results. Furthermore, incorrect variation between nodes arising from the nodal approach are far more unacceptable than an average approach which doesn't seek to identify variations between nodes within a Network Group. It is not considered practical to develop, implement, and validate a true nodal analysis in less than 18 months and this could take much longer as there appears to be no previous theoretical development. In contrast the Network Group approach can be much more readily implemented on different companies' computer systems and be more readily checked and validated by both the companies themselves and to some extent by customers.