SSE Response to NGC's GB Transmission Charging: Final Methodologies Consultation

Executive Summary

SSE does not support the use of NGC's DC Load Flow model for setting GB wide transmission tariffs. It results in extreme locational signals that are at odds with NGC's licence obligation to facilitate competition in generation and supply of electricity.

Cost reflectivity can be achieved simply by ensuring the charges recover the total costs of NGC. Both of NGC's models achieve this criterion, as would a "postage stamp" pricing model and a wide variety of other approaches. Facilitation of competition, on the other hand, implies a range of tests such as transparency, objectivity, and stability in order to give an environment which encourages investment and new entrants. These two issues mean that there is unlikely to be a "right" answer and each potential solution needs to be assessed against a range of criteria.

If the model is to be used, SSE supports option A, where a single expansion constant is used irrespective of voltage. We believe this option more correctly reflects the economic principles underpinning long run pricing, and better meets NGC's licence obligations, particularly facilitation of competition.

If NGC continue to support option B, they should at the very least use a weighted average 275kV expansion constant, as has been done for 132kV. Failure to do so would be perverse and discriminatory

1. Introduction

NGC have now published their proposals for GB Transmission Charging under BETTA. The proposals are based on the application of a DC Load Flow (DCLF) model to derive locational tariffs. We so not support the proposed methodology, since we believe it results in perverse and extreme locational signals. We have nevertheless set out below our comments on the suitability of this particular model with reference to both the licence conditions and general economic principles. These comments are made on a without prejudice basis and we reserve the right to amend these views as the process develops or exercise any remedy available to us to protect our position.

2. Consistency with existing E&W model

NGC have used the current E&W model as a basis for setting the initial GB charges. Necessary changes to the model include the addition of the Scottish transmission network data into the model. Had the Scottish network comprised simply 275 and 400 kV network then no changes to the model specification would have been involved. However, since the Scottish transmission system also includes 132kV network, parameters in the model had to be extended to cater for this new voltage.

In extending and reengineering the model, it has become clear that not all of the features of the model can be retained if it is to be extended to Scotland. In both the preferred option and the alternative option, fundamental changes have been made to the methodology.

- In option A, the only change is to use a single expansion constant for each route section, representing the costs of a new 400kV circuit (overhead line or underground cable depending on the existing route configuration).

- In option B the ratio of generator and demand charges has been arbitrarily altered to 90% demand, 10% generation to avoid demand charges going negative.

We believe there is an economic rationale for using a single expansion constant (as per option A) and explain these arguments in section 3 below.

There is no economic rationale for the arbitrary redistribution of costs in option B. NGC have normally justified each decision regarding model parameters with their view as to how it might better comply with their licence obligation. However, no such justification is presented as to why a 90/10 split is correct. It is simply the proportion that demand customers would have to pay to avoid north of Scotland demand charges being negative. Negative demand charges in the GB model only occur when multi voltage expansion constants are used.

In their previous consultations, the split of charges in the multi voltage model has moved from 73/27 in their December 2003 consultation, to 80/20 in April 2004, to 90/10 in this consultation. These readjustments serve to make their consultations less transparent, since the two options are not directly comparable. They also serve to increase the expectations of E&W generators of significant reductions in their charges, when NGC appear to have no authority to move away from the 73/27 proportions currently applying in E&W.

In any case, the split between generation and demand charges is essentially a regulatory decision, rather than an economic one. Indeed, there are European arguments for the charges to fall 100% on demand. Whatever the regulatory decision is on the correct ratio, we believe the same should be applied to both options.

3. Expansion Constants

Expansion constants are used as a proxy for the cost of providing additional capacity on the network. We continue to believe a single expansion constant is the correct approach in economic terms.

We also believe NGC's proposed approach is perverse and discriminatory in failing to adjust the 275kV expansion constant in the same way as the 132kV constant has been adjusted. Our detailed comments are set out below.

3.1. Single Expansion Constant

We continue to believe that if the DCLF model is to be used, it should have a single expansion constant for each route reflecting the long run incremental cost of the most efficient means of providing extra capacity. In economic terms, short run costs are those which apply when capacity cannot be changed, whereas long run costs relate to those where capacity is matched to demand. In a long run model, we believe that the correct economic answer is to use costs (i.e. expansion constant in this model) of the most efficient and economic way of providing extra capacity. The most economic way, in other words, the cheapest capacity solution, is 400kV.

Furthermore, the expansion constant itself is applied to the existing system and the routes available in that system. It does not, and cannot, deal with redesign of the network for future expansion. All that can be done is to rerun the model as and when the network is modified and extended. On this basis the expansion constant can only be a generic proxy for the cost of additional capacity and should not be taken to be indicative of redesign of the network to provide new capacity. This approach also supports the use of a single expansion constant reflecting the most efficient means of providing additional capacity.

For both the above reasons, we remain of the opinion that for this type of model, the correct expansion constant to use is one reflecting the most economic option for uprating route capacity, regardless of the present voltage of that line route. This is not only the correct approach from a long run cost argument, but we believe it is also the correct approach in better meeting NGC's absolute licence condition to facilitate competition in generation and supply.

3.2. Multi-Voltage Expansion Constant

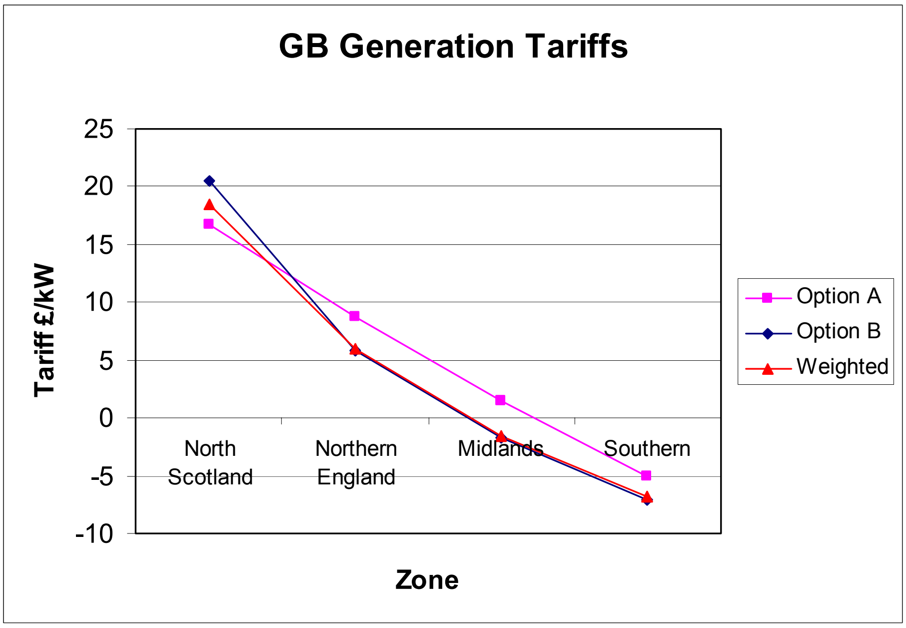
NGC's preferred option uses different expansion constants for the different voltages in the model. However, they have now proposed a variation to "reflect the proportion of (132kV) circuits likely to be uprated" to 400kV. From data supplied by the Scottish transmission companies, NGC have calculated that this proportion would be 20%, which we would agree is the correct proportion. The expansion constant for 132kV circuits used in the load flow model is then based on a weighted average of the 132 and 400kV expansion constants, i.e. 80% of the 132kV cost and 20% of the 400kV cost. Again, we would agree that this is the preferred approach if NGC remain committed to multi voltage expansion constants in the model.

Having recommended applying an expansion constant for 132kV which reflects the likely proportion to be upgraded to 400kV, NGC have unaccountably failed to carry out the same calculation for the 275kV system. This omission is perverse and discriminatory in its effect. This is because the Scottish "supergrid" of 275 and 400kV circuits accounts for nearly half the GB 275kV system, but only 7% of the GB 400kV system. Also in Scotland nearly 80% of the supergrid system is 275kV, whereas in England and Wales it is less than 25%. Failing to take account of this is discriminatory against Scottish customers. This is shown by the sharp upward tilt in charges resulting from option B as opposed to option A, which has a single expansion factor.

More significantly, the E&W system is bounded by 400kV circuits. The "cage" created by the 400kV circuits has the effect of protecting E&W generation and demand from the effects of multi voltage expansion constants. This can be demonstrated by running NGC's own model used to calculate the 2004/5 E&W tariffs but using a single expansion constant. The maximum change in tariff is only £0.3/kW. More typical is a change of £0.10-£0.15/kW. The effect of carrying out this adjustment or indeed of using a single expansion constant (as NGC has done every year since privatisation except in 2004/5) is not material for E&W customers.

Against this the difference in the north of Scotland generation zone charges between options A and B, even after reducing the generation contribution under option B to only 10% of the GB total, is nearly £3.86/kW. Without this rebalancing, the differential would be nearly £6/kW.

Clearly, the proportion of 275kV system that would be upgraded to 400kV has a material effect on Scottish generation and demand charges. Making this correction has no material effect on E&W charges, and would serve to greatly reduce the perceived discrimination in the model. The discriminatory "tilt" produced by option B compared to option A is illustrated in the graph below, together with the mitigating effect of using a weighted average 275kV constant, 50% in this example.



We therefore firmly believe that NGC should use a weighted average expansion constant before submitting final proposals to Ofgem.

3.3. Weighted Average Expansion Constant

If NGC are not persuaded by the arguments set out in 3.1 above to use the same expansion constant for 275 as for 400kV, at the very least it should be a weighted average of the 400 and 275kV figures. A failure to make this adjustment would in our opinion be perverse, since the same adjustment has been done for the 132kV circuits, and discriminatory against Scottish customers for the reasons discussed in 3.2 above. In carrying out this correction for the Scottish 275kV system there are two adjustments that need to be made.

Firstly, for consistency with the treatment of 132kV circuits, the proportion of circuits already identified within the GB studies for renewable generation that would be uprated to 400kV if required. In SSE's area, this is approximately 50%.

Secondly, many 275 kV circuits at present are in fact 400kV circuits running at 275kV because of the historic development of the system. Early 275kV circuits were of a spacing and ground clearance that would require rebuilding to uprate to 400kV. When 400kV became the preferred voltage for "supergrid" construction, newer circuits linking the existing 275kV substations were constructed to 400kV specification to facilitate future upgrading as load developed. In other words the connection into the existing infrastructure has dictated their initial operating voltage, but any subsequent upgrade to 400kV would only involve equipment at the substations at the ends of the line, which does not form part of the expansion constant in this model. Since these circuits are in effect 400kV circuits, it would therefore be appropriate to use the 400kV expansion constant for them.

Again, around 50% of circuits in SSE's area fall into this category, although half of these have already been identified as potential 400kV upgrades as part of the network studies mentioned above.

Combining these two factors implies that 75% of the 275kV circuits in SSE's area should be factored into the GB weighting calculation for the 275kV system. In NGC's area we believe the adjustment would be 100%, since NGC appear to have invariably uprated to 400kV when new capacity is required on a 275kV route as evidenced in Table 6.2 of the NERA report.

4. Security Factor

NGC have continued to use a locational security factor in the model. We continue to believe this is flawed for the following reasons.

The model uses the actual network data, which reflect a network that is fully compliant with the planning and operating standards. Furthermore, the network load flow is carried out under "peak" conditions, in which circumstances all circuits would normally be available (no planned outages). The load flows resulting from this network are therefore already secure, and so it is incorrect to apply a further "security factor".

Also the derivation of the security factor is obscure. It can only be derived by NGC running a range of outage scenarios and using a statistical analysis on these results. Unlike the load flow, it is therefore impossible verify the result independently.

We therefore believe a security factor cannot be justified on economic grounds and serves to make the process less transparent.

5. Cost Reflectivity and Stability

We believe that NGC have failed to take into account the stability and cost reflectivity concerns that have been raised. Common sense suggests that existing and new generators in the same area should pay the same transmission charge. It also suggests that the charge actually paid should become *lower* as new generators are connected to the existing system because the same total revenue is spread over a greater number of contributors. This would be a genuinely cost-reflective and stable model. We have tested this aspect of the model with 1,000MW of new generation in SSE's area that can connect without driving additional investment in transmission capacity.

Under NCG proposals the exact opposite happens, and both option A and option B result in *higher* charges to both existing and new generators in Scotland. This is because the effect of the model is to make them bear extra charges in anticipation of possible future costs of expanding the transmission system capacity. Other generators' charges are reduced since the overall income from generators remains unchanged.

Under option A, the existing Scottish generators would pay around £2.5m per annum more as a result of the addition of 1,000MW of new generation in the north of Scotland. In other words, the total costs of the system remain unchanged but existing generators are forced to pay extra because of newcomers. In option

A, this redistribution effect is relatively small, because the parameters of this version of the model mean that is inherently more stable to these changes.

Under option B, however, the existing Scottish generators would have to pay an extra £7.5m per annum, three times the additional costs of option A. Note that this increase is simply as a result of the 1000MW of generation that is already expected to connect in the north of Scotland in the near future. It does not take into account the additional generation in south Scotland or further generation in the north which would further exacerbate the problem.

In both options, generators in other areas receive the benefit not only of the increased charges to existing Scottish generators, but also the charge to new generators as illustrated in the table below:

Total payment of GB TNUOS charges £m	Option A		Option B	
	Proposed	Additional 1000 MW	Proposed	Additional 1000 MW
Existing Scottish generators	119	121	112	120
New Scottish generators		17		21
E&W generators	181	162	(2)	(31)
Total	300	300	110	110

While we would not expect charges to remain absolutely stable, there is clear evidence that option A is more stable than option B, particularly at the extremities of the system. Greater stability results in greater predictability and hence lower risk for participants. If generators, particularly renewable generators, perceive a lower risk as a result of the tariff methodology, then this will clearly facilitate their project finance, and in turn will facilitate competition in generation, which is a fundamental objective of the tariff methodology, and indeed the licence.

6. Choice of Extreme Parameters

In our previous response, we concluded that it would be essential, if this DCLF model is to be used, to carefully select the parameters of the model so as to ensure stability of tariffs. The Illustration above shows how option B is less stable than option A and this instability is linked to the choice of parameters in the model. The more extreme the parameters and hence the more punitive the locational signals, the less stable the model is to changes to generation and system reconfigurations.

A key indicator of the severity of the locational signals produced by the model is the tariff differential that exists between the North of Scotland, where generation is discouraged from locating, and the south west of England, where generation is encouraged. Under option A, this differential is £24/kW, and under option B is £31/kW, an increase of 30% from option A to B.

This difference is caused by the use of multi voltage expansion factors. However, the impact can be reduced by using a weighted average of the 275kV and 400kV expansion constants.

The second driver of the locational signal is the zonal application of a security factor to account for potential additional circuits providing secure transfer. We have argued against applying this further factor, but NGC have retained it in their proposals. The possible range of security factor is between 1 (where no additional circuits are built in) and 2 where a duplicate circuit is installed. The derivation of this factor is particularly opaque, but NGC have opted for a figure of 1.8.

The table below shows the range of possible outcomes of the North/South differential depending on the choice of the security factor, and the weighting applied to the 275kV costs.

Table of £/kW Differentials with various Security factors and 275kV weightings						
	Security Factor					
Weighting of 275kV EC	1	1.2	1.4	1.6	1.8	2
100% (option B)	17	21	24	28	**31**	35
75%	17	20	23	27	30	33
50%	16	19	22	26	29	32
25%	15	18	22	25	28	31
0% (i.e. option A)	14	16	19	22	**24**	27

The £31/kW differential is at the upper end of the range of possible zonal differentials with this model. In fact there are only 3 combinations that would result in a higher differential than this. The average differential across all possible combinations is £24/kW, the same as under option A.

This table does not address the issue of spare capacity, which NGC have ignored in their model, even though there is significant spare capacity in the north of Scotland at present.

7. Negative Demand Charges

We note that NGC have proposed adjusting the G:D split to 10:90 in order to ensure that demand tariffs remain positive. We continue to believe that the model is flawed if it produces tariffs that provide perverse signals. As noted in section 2 above, we also do not believe that adjusting the G:D split is within NGC's gift. This split is a regulatory decision rather than an economic one. The avoidance of perverse signals can be achieved by an appropriate choice of parameters as outlined above, in particular, by

- adopting option A,
- carrying out the same adjustment to 275kV circuits as has been done for the 132kV system, or
- using a lower security factor.

However, given the movement within Europe to harmonise generator charges to zero, we believe that moving to a 10:90 split of charges is moving in the right direction.

8. 132kV "Discount"

Ofgem has separately concluded that it would be appropriate to provide an interim discount in transmission use of system charges to generators connected to the 132kV system in Scotland. This is to mitigate the disparity in charges between generators connecting to the 132kV system in Scotland and the 132kV distribution system in England & Wales. However, Ofgem have concluded that the discount should be the "residual" element of generator charges resulting from NGC's model. Initially, this discount was expected to be around £3.50, still substantially less than the estimated average benefit in excess of £6/kW enjoyed by generators in E&W. NGC's decision to recommend option B has further eroded this to only £1/kW. If the G:D split is further altered to 0:100 in line with European policy, the "discount" would be negative. This illustrates the error in assuming that this number within the model has a cost-reflective basis. Rather, it is simply a balancing term to ensure overall cost recovery. While not an issue for the model specifically, it does prove that Ofgem need to reconsider the level of the 132kV discount as set out below.

In the November 2003 "small generators" consultation, Ofgem concluded that the use of system benefit of connecting at distribution is in fact the sum of the generation and demand residual charges:

"The net benefit of a small embedded generator being able to count its output against the demand of a local supplier is the residual charge avoided by the generator plus the residual charge avoided by the supplier."

Unlike each component separately, the sum of residual charges in not affected by the G:D split, and is £15 in the current model.

Again, in the November consultation, Ofgem subtracted £6.60 of assumed costs of connecting at distribution level. The same calculation would result in a net benefit of £8.40, rather than £1.20 as proposed. We believe that this should be the basis of the 132kV discount.

9. Phasing of Charges

NGC have dismissed the possibility of phasing in the new charges over time. Although NGC have stated that generator charges pre and post BETTA are broadly comparable, we do not agree with this conclusion. For example, under option B Scottish generators pay more than the entire cost of the generation element of use of system. E&W generators receive a net payment, compared to around £250m at present. These are enormous swings in charges, and there is a precedent for phasing in new charges when the ICRP model was first introduced in E&W.

10. Other Issues

The discussion in the above sections set out our main concerns with the GB methodology, focussing particularly on the use of system charges. The following points relate to issues in the connection charging methodology.

10.1. Generator Spurs

NGC have indicated a problem with certain short “generator spurs” in Scotland, stating that there is an “implicit” rule stating that any circuits less than 2km would be counted as connection asset. NGC have also stated that this rule applies to demand connections however, we can see no explicit reference to demand connections in the current E&W methodology.

We believe it is essential to have all the rules clearly stated, so that users understand which assets will be counted as infrastructure, and which as connection.

The “2km rule” would therefore appear to be an additional constraint on the connection charging methodology, and we therefore believe that NGC should consult on the merits of this new rule, rather than simply refer to implicit assumptions in their methodology.

10.2. Site Specific Maintenance

We agree with NGC’s proposal to calculate site specific maintenance charges on the basis of a percentage of the asset values. We believe this is consistent with the GB objectives of minimising the implementation cost, while retaining overall cost reflectivity.

10.3. Metering Charges

In discussion on converting existing connection agreement to CUSC bilateral agreements, there appears to be a discrepancy between the depreciation period for electronic meters. In SSE, these are only certified for 10 years, and therefore need to be replaced at that interval. NGC appear to use a 15 year period, which would result in under recovery of meter costs. The final methodology should therefore allow for appropriate variations to meter certification life.