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Transmission charging and the GB Wholesale Electricity Market – Part 2
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The aim is to meet a target for renewable generation. Hence, after allowing for government subsidies to renewables capacity construction, the excess of the prices paid by suppliers to renewable energy generators (net of transmission loss factors) over the TUOS charges paid by those generators, must be sufficient to remunerate investment in the target level of renewables capacity. Consumers must somehow share the cost of this excess, either (i) through higher prices for renewable energy or (ii) through lower TUOS charges for renewables generators offset by higher TUOS charges for all other generation

This should be done at minimum cost, which requires that locational **differences** in TUOS charges and in transmission loss factors should reflect **differences** in long-run marginal transmission costs and **differences** in marginal transmission losses. [*Note the artificiality of divorcing consideration of TUOS charges from discussion of transmission losses*.]

Differences are preserved by a uniform absolute shift, **not** by a % scaling or by discrimination in favour of peripheral areas. [The first sentence of para 7.22 is nonsense.]

NGC's July paper on its Initial Charging Methodologies Consultation proposes an improvement upon the ICRP approach to TUOS, but a much better one, which I have proposed to Mike Calviou, would be as follows, involving the following steps:

1. Estimate a number of backgrounds — assumptions about demand in each GSP group and a pattern of generation to meet that demand and provide for the losses. This pattern should not just be a scaling down from capacities but should approximately reflect merit order.
2. For each pair of a generator and a GSP group compute Power Distribution Factors for each boundary for each background.
3. Estimate the cost per MW of increasing the capability of each boundary by whatever means (quad boosters, reconductoring, new lines etc.) appears most economic.

4. For each background for each pair of a generator and a GSP group postulate a matching increase in generation and offtake, multiply by the Power Distribution Factor for each boundary and, if this would raise the cross-boundary flow above that boundary's capability, multiply by the cost per MW of increasing the capability of that boundary
5. For each pair of generator and each GSP group multiply the result for each background by the probability attached to that background and sum.
6. Consider how and whether the complex results can be simplified by defining *N* generation zones, averaging the results for the generators within each and, if there are *M* GSP groups, expressing the $M \times N$ marginal costs as *M* exit charges and *N* entry charges.

The *Seven Year Statement* shows that quite a bit of this probabilistic work has already been done.

As regards step 6, note two possibilities:

1. Instead of examining incremental or decremental point to point flows, ***N*** entry charges are computed on the assumption that the increase in demand matching a postulated increase in generation at each particular location is spread proportionally over all GSPs. Similarly, ***M*** exit charges are computed on the assumption that the increase in generation matching a postulated increase in demand at each particular GSP is spread proportionally over all generation locations.
2. All ***MN*** marginal costs are estimated and then regressed upon zero-one dummy variables for each generation location and each GSP, with the constant term constrained to zero. The resulting $\boldsymbol{M+N}$ dummy variable coefficients then provide the entry and exit charges. This was done by TRANSCO with Transcost results, though minimising the sum of absolute deviations would seem more appropriate than minimising the sum of squared deviations.