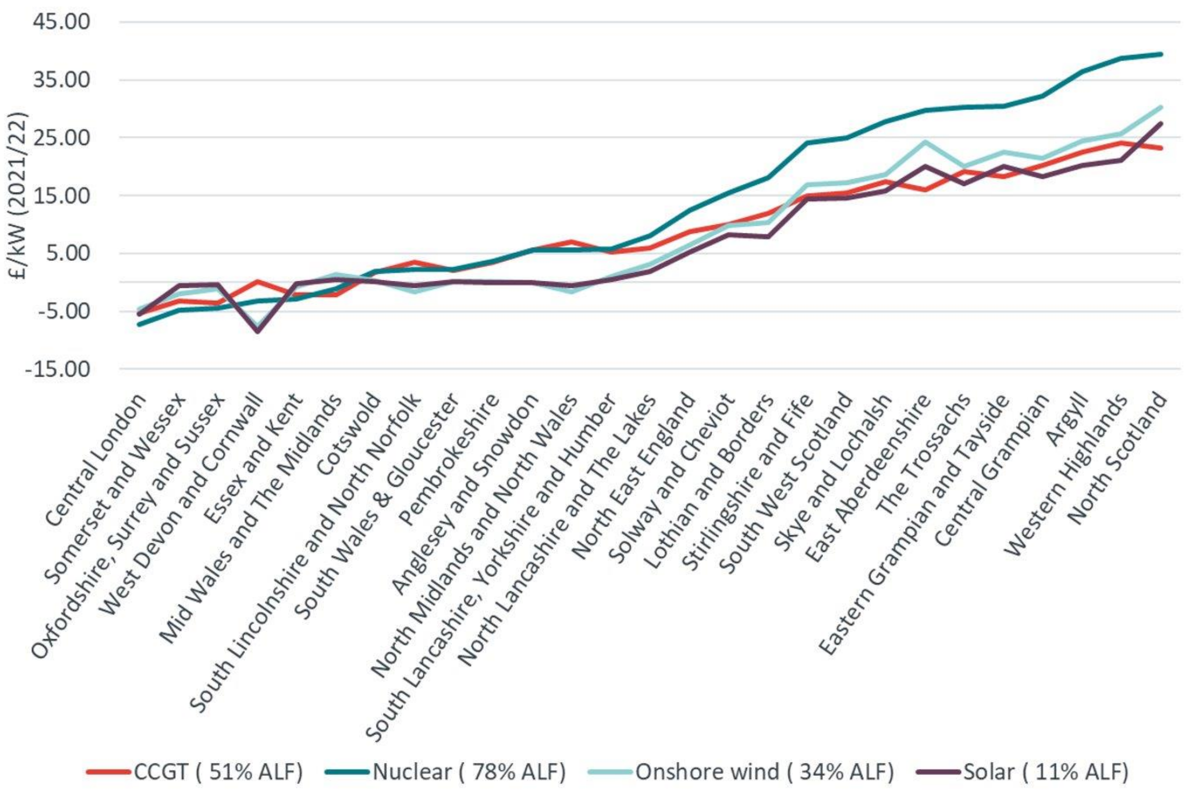
Annex 3 - Background to the current TNUoS methodology

Background to the current TNUoS methodology

Current GB locational TNUoS charges are derived based on an Investment Cost Related Pricing (ICRP) methodology, which seeks to assess the marginal impact on the need for network investment of incremental generation, or demand, at different points on the network. This methodology is based on long-run marginal costs i.e. it is related to the incremental cost of developing the network from its current state. This is in contrast to alternative methodologies based on short-run marginal costs.

The core tool for calculating charges is National Grid's proprietary DCLF ICRP Transport Model,[1] which estimates a marginal investment cost for each transmission node across GB. Nodal charges are averaged within each of the 27 generation charging zones to result in zonal generator charges. These are negative in southern zones and rise to significant positive charges in northern zones, as illustrated below in Figure 1. The charges also vary by technology reflecting the fact that for a given location it is expected that different technologies result in different incremental impacts on network costs.

Figure 1 Illustration of north south gradient of locational generation TNUoS



[1] https://www.nationalgrideso.com/industry-information/charging/tariff-model-tnuos#:~:text=(DCLF%20ICRP%20Transport%20Model),demand%20tariffs%20under%20different%20scenarios.

Annex 3 - Background to the current TNUoS methodology

A similar approach is taken to calculate demand charges, but demand charges are calculated for each of the 14 demand charging zones, with charges higher in the south and lower in the north.[2]

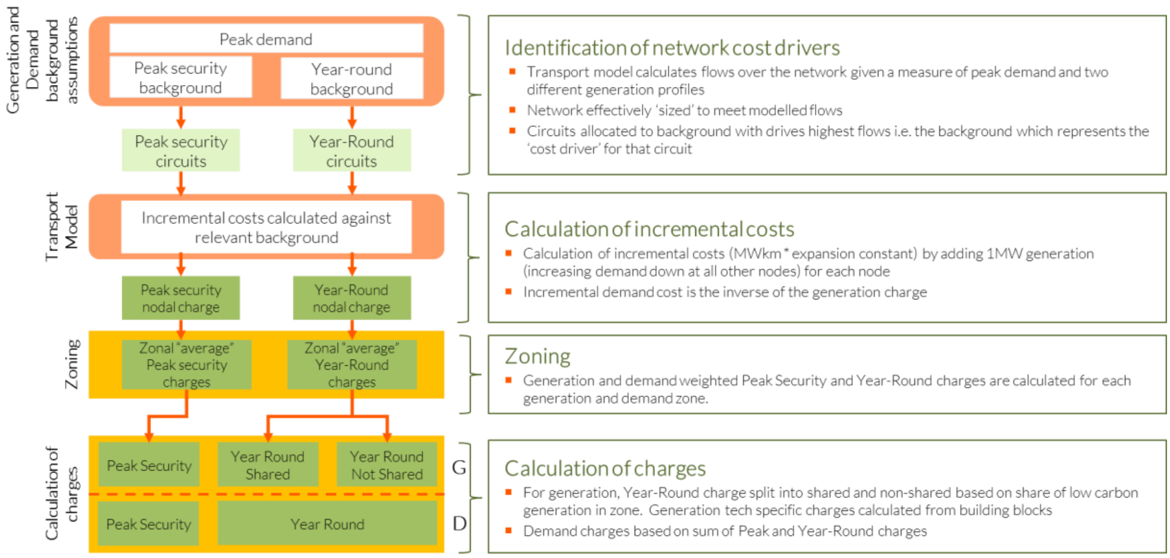
The absolute level of charges in any zone arising from the ICRP model depends on specific detailed assumptions and is somewhat arbitrary.[3] It is the relative investment signal (i.e. the cost of investing in capacity in zone A relative to zone B) that is more important, and is effectively the key output from the process.

The TNUoS methodology for calculating these charges is complex, and comprises a number of building blocks. These building blocks have developed over time in order to improve the cost reflectivity of charges as the system has evolved. In particular, Project Transmit led to changes to the ICRP methodology to better reflect:

- the way the transmission system was actually developed, which was changing as a result of the move to a low carbon energy sector; and
- the impact of different technologies as drivers of incremental network investment.

The core building blocks of the current TNUoS methodology are summarised below in Figure 2.

Figure 2 Illustration of current TNUoS methodology



Each of the core building blocks of the TNUoS methodology are discussed briefly in turn below.

---

2 Whilst the current TNUoS methodology calculates negative locational charges (a TNUoS credit) for demand in certain zones these charges are ultimately 'floored at zero' to prevent demand users being provided an incentive to increase consumption during periods of peak demand.

3 It is worth noting that the absolute level of charges for generation is capped at €2.50/MWh on average.

Annex 3 - Background to the current TNUoS methodology

Identification of network cost drivers

First, the Transport Model is used to estimate flows over the network given a measure of peak demand and two different generation profiles, with the technology mix in each set according to the CUSC:[4]

- A '*Peak Security*' background which assumes that transmission system peak demand is met equally from all sources of generation apart from intermittent generation and interconnectors (which are assumed to have zero output); and
- A '*Year-Round*' background which assumes significant contributions from intermittent generation and that interconnectors are in full import mode.[5]

The purpose of the backgrounds is to capture the fact that network expansion, according to the SQSS, may either be driven by the security criterion i.e. to secure the network at times of peak demand, or the economy criterion i.e. to reflect a trade off between the cost of building additional transmission assets and the cost of constraints.

For each background, the network is assumed to be able to perfectly accommodate these flows, and no more. Each individual network circuit is tagged to one of the two backgrounds based on which triggers the largest flow over that circuit, and hence is most likely to represent the scenario in which network investment could be triggered.

Calculation of incremental costs

The incremental expansion of the network required to accommodate incremental use at each node is calculated by modelling the change in transmission capacity required when 1MW of generation capacity is added at a node, matched by a 1MW increase in demand spread across all nodes. This calculation is performed for each background. Estimated Year Round and Peak Security incremental costs at each node are then calculated by multiplying the modelled incremental expansion of the network (in units of MWkms) by an expansion constant which represents the average unit cost of building additional transmission network capacity.[6] Incremental demand costs are simply the inverse of the generation costs at each node.

Zonal averaging

The nodal charges calculated are then averaged to derive zonal charges for 27 generation zones and 14 demand zones. This reduces the risk of spurious accuracy of locational signals and likely reduces the volatility of end charges relative to the raw nodal charges.

---

4 https://www.nationalgrideso.com/document/91411/download. Para 14.15.7

5 https://www2.nationalgrideso.com/document/278386/download Table 1.5

6 The Expansion Constant (EC) is an element of the TNUoS charging methodology that determines the £/MW/km value of a 400kV Over Head Line (OHL). Source : https://www.nationalgrideso.com/document/178981/download

Annex 3 - Background to the current TNUoS methodology

Calculation of final charges

The Peak Security and Year-Round charges are then converted into final generation and demand charges:

- For demand, charges are simply based on the sum of Peak and Year-Round charges and charged based on peak demand (i.e. Triad demand); while
- for generation, the total charge is split up into a Peak charge and a Year-Round charge. The Year-Round charge is split into "shared" and "not shared" elements (with the split depending on the proportion of low carbon generation on the system) to capture the ability of different types of generation assets to jointly use transmission assets without creating constraints. As a result, the Shared element is discounted by a plant's Annual Load Factor (ALF) for all generation technologies but the Not-Shared element is only discounted by ALF for conventional carbon generators. Technology-specific generation charges are then calculated from these building blocks.