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Current arrangements

Summary

This note provides a summary of current access and charging arrangements.

Access arrangements

Distribution access

1.1. Access to the distribution network is allocated through the connection process, on a first-come-first-served basis. Where there is a connection queue, the network companies have worked with stakeholders to agree an approach for managing this queue.[1] This includes introducing "connection milestones" for projects in the queue to demonstrate the progression of the connection project. If the customer does not meet these milestones (eg planning permission applied for or agreed) and there is insufficient evidence of progression, the connection project may be removed from the queue, or have its queue position demoted, and the capacity reallocated to other connection projects that are progressing. This supports the efficient and fair allocation of network capacity.

1.2. At distribution, most customers have no (or limited choice) about the terms of their access. The current access arrangements are also often less well defined and are not explicit about the nature of access rights being granted to the system.

1.3. Financially firm access to the distribution network is not currently available and there is not currently a clear security standard for distributed generation (DG). Most distribution-connected generators can choose to have a "traditional connection" or a "flexible connection":

- **Standard connection** - Under this approach a Distribution Network Owner (DNO) will evaluate whether the user can be connected to the existing network or whether reinforcement is needed to connect them, in which case the user is liable for a proportion of the reinforcement costs. In doing so, the DNO would

[1]http://www.energynetworks.org/assets/files/news/publications/Reports/ENA%20Milestones%20best%20Practice%20Guide.pdf

ensure that there is sufficient network capacity available so that curtailment is rare, typically only for maintenance reasons. Excluding these instances, where the DNO wants to curtail users with a standard connection then it must pay for this flexibility through a flexibility contract.

- **Flexible connection** – This "non-firm" access allows the connecting customer to be connected more quickly and avoid its contribution to reinforcement costs, in exchange for the risk of open-ended curtailment without the opportunity to agree a payment. The DNOs provide an estimated curtailment rate, but no cap is defined on the level of curtailment that can be incurred.

1.4. For both demand and generation users, most access rights are provided on a continuous, year-round basis.[2] Access rights are issued to an individual (rather than being shared between users) and, once connected, access rights generally do not include conditions of access (eg use-it-or-lose it or use-it-or-sell-it).

1.5. Larger distribution-connected users[3] (both demand and generation) typically have an agreed maximum import or export level for the distribution network. However in contrast, most small users[4] do not currently have a well-defined access level to the wider system. In practice, most are only limited by their fuse size or service cable and may never have considered or 'chosen' the level of access they require.

Transmission access

1.6. Transmission access is allocated through the connection process, on a first-come-first-served basis. Transmission-connected generators and large generators connected to distribution networks have explicit access to the transmission system.

1.7. As part of the connection process, transmission-connected generators and large generators connected to the distribution network agree their required Transmission Entry Capacity (TEC). This access to the transmission system is "financially firm". Generators typically agree payments when their output is curtailed due to network constraints, up to the level of their agreed capacity. The "Connect and Manage" regime enables generators to connect ahead of wider network reinforcements, if needed, and their connection agreement

[2] Some individual users have agreed time-profiled access rights.
[3] By larger distribution-connected users here, we are referring to those distribution-connected users who have an agreed capacity, which is the basis for their DUoS charges. Typically, these users will have current transformer (CT) meters (used for connections above a certain size).
[4] Users that do not have an agreed capacity. These users are typically not CT metered.

will outline the circumstances in which they will/will not receive payments if they are constrained. The associated cost of these payments is socialised across other users. Eligibility for constraint payments is dependent on meeting network security standards set out in the System Quality and Security Standard (SQSS) and other conditions of their connection.

1.8. For the majority of distribution-connected users, their access rights do not explicitly define their ability to access the transmission network.[5] Where a generator seeking to connect to the distribution network may have an impact on the transmission network, the Statement of Works process[6] requires the likely impact on the transmission system to be assessed. Where distributed generators are unable to connect due to transmission constraints, they may be able to benefit from the 'Connect and Manage' regime.

1.9. Transmission-connected demand do not have an equivalent to TEC (ie transmission-connected demand do not have a bilaterally agreed maximum import capacity). Transmission-connected demand must submit accurate forecasts of their required power (for end customers this is typically facilitated through suppliers on their behalf), which they expect to have use of, subject to provisions in codes and elsewhere. With no clearly defined access rights, transmission demand users can import up to the maximum amount that their connection assets will allow them to.

1.10. For all transmission-connected users, most access rights are provided on a continuous, year-round basis. Transmission-connected generators can get short-term and limited-duration TEC (eg periods less than a year) but this is not commonly taken up.

1.11. At transmission, like distribution, rights are issued to an individual (rather than being shared between users) and generally do not include conditions of access (eg use-it-or-lose it or use-it-or-sell-it).

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[5] Some small DG can agree the ability to export to the transmission system – through a Bilateral Embedded Generator Agreement (BEGA), which provides them with formal Transmission Entry Capacity, or may have a Bilateral Embedded Licence Exemptible Large power station Agreement (BELLA), as applicable.

[6] When a DNO receives a request from a generator intending to connect to the distribution network which it believes will have a significant impact on the transmission system it is required to request NG ESO, in conjunction with the relevant TO, to perform some analysis to determine whether there would be an impact – this is known as the 'Statement of Works' process. More information can be found on each of the DNOs' websites.

Connection charges

Distribution connection charges

1.12. All electricity distribution licensees are required by Standard Licence Condition 13 to have in place a connection charging methodology which has been approved by us. For DNOs, this is the Common Connection Charging Methodology (CCCM) which is set out in DCUSA Schedule 22. IDNOs have their own connection charging methodologies in place.

1.13. If a DNO is providing the connection the charge will be based on the cost of the "minimum scheme". The minimum scheme is the solution designed solely to provide the capacity needed for the new connection at the lowest overall capital cost (but not necessarily the lowest cost for the connecting customer). A DNO may design an enhanced scheme, but the cost to the customer will not exceed that of the minimum scheme. The customer can also request work in excess of the minimum scheme where it thinks this would be more beneficial. For example, it may request that electrical equipment of a higher rating is installed to allow for the potential of future expansion. The customer will need to pay the full cost of this additional work, including the cost of operating and maintaining these additional assets over their lifetime.

1.14. Connecting customers pay for the full costs of the connection in advance, before the connection is made live. The degree to which the connecting customer has to pay for any wider reinforcement that is needed (in addition to assets which are only to be used by that customer) is called the connection charging boundary. This helps to provide a signal to customers to connect where there is spare capacity on the network.

1.15. Customers connecting to the distribution network face a "shallow-ish" connection boundary.[7] That is:

- The connecting customer pays for the assets required to connect to the existing distribution network ("extension assets").

[7] This replaced a deep connection charging boundary in 2005 where distribution connected generators paid for all reinforcement that was required. Several other changes were also made at this time including removing the ability of DNOs to recover connection charges through long term use-of-system charges, recovering capitalised operation and maintenance costs from use-of-system charges instead of connection charges, introducing a common approach to apportioning reinforcement costs between connecting and wider customers and removing the rule that customers are only charged for Reinforcement if requested connection is 25% larger than capacity at that point.

- The connecting customer contributes to reinforcement up to one voltage level above their point of connection.

1.16. The customer's contribution to reinforcement is calculated by two cost apportionment factors (CAF) so that the connecting customer pays for the proportion of the new capacity it requires.

1.17. Any reinforcement at two voltage levels or above the point of connection is socialised across the DNO's wider customer base and recovered through Distribution Use of System (DUoS) charges. This reflects the wider benefit such reinforcement provides. The exception to this is that DG connecting customers pay for any reinforcement costs in excess of a high cost cap (HCC) of £200/kW, regardless of what voltage those costs occur at.

1.18. Where an existing user wants to vary their access rights (eg by requesting an increase to their agreed maximum import or export capacity), then they could face a connection charge. However, where, for example, network reinforcement is triggered by an existing premises below 100 amps per phase (ie domestic and small businesses) installing EV charging infrastructure, all reinforcement costs are paid for by DUoS customers.

1.19. In some circumstances, where a person connects to, and benefits from, electricity infrastructure that was paid for by an earlier party, the earlier party can be reimbursed by the subsequent connecting customer. These regulations are known as the Electricity (Connection Charges) Regulations 2002 and 2017 (ECCR) or 'second comer' regulations.

Transmission connection charges

1.20. Standard Licence Condition C6 requires transmission licensees to have a connection charging methodology which has been approved by us. The connection charging methodology is outlined in the Connection and Use of System Code (CUSC).

1.21. As with distribution, the charge is based on the lowest costs scheme required to provide the customer's required capacity. The minimum scheme must be the one with the overall lowest capital costs (but not necessarily the lowest cost for the connecting customer).

1.22. Connecting customers face a shallow connection charging boundary. That is, they individually pay for their own Connection Assets[8] (that are not potentially shareable). Potentially shareable assets and network reinforcement are then paid for through Transmission Network Use of System (TNUoS) charges. Connecting customers can choose to pay for the cost of the Connection Assets upfront (eg staged payments in line with the Transmission Owner (TO) construction programme or upon energisation) or pay annualised charges over a 40 year period.

1.23. Some customers[9] are also required to place security to cover a proportion of the money spent by the licensee in providing the connection (the methodology for calculating the level of security required if referred to as the "user commitment" methodology). User commitment places liabilities on users in the event that they cancel or delay their projects. This means that users help financially secure the network reinforcement and investment needed to connect them. The amount of security required equivalent is a proportion of the total network reinforcement and investment needed to connect them.[10]

1.24. The User Commitment methodology helps to ensure that TOs have enough information to plan and develop the network economically and efficiently. As a result, this commitment protects consumers' interests and those of the wider industry. It gives users an incentive to provide accurate and timely information about their needs. It also ensures the risk of stranded assets is put on the parties that are best placed to mitigate and manage that risk.

1.25. The Electricity System Operator (ESO) contracts bilaterally with the customer and also with the relevant TO to facilitate the connection and administer any user commitment agreement. The ESO develops the security statement based on data provided by the TO and uses the user commitment methodology set out in the CUSC. Customers may provide a cash sum, letter of credit or performance bond as security depending on the individual case. Where the customer provides a cash deposit as security, the ESO holds the money in

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[8] Connection Assets are defined as those single user assets which:

- For Double Busbar type connections, are those single user assets connecting the User's assets and the first transmission licensee owned substation, up to and including the Double Busbar Bay;
- For teed or mesh connections, are those single user assets from the User's assets up to, but not including, the HV disconnector or the equivalent point of isolation;
- For cable and OHL at transmission voltage, are those single user connection circuits connected at transmission voltage equal to or less than 2km in length that are not potentially shareable.

[9] These include DNOs on behalf of projects requiring transmission reinforcement, connected projects with one-off costs or connection asset charges, all transmission-connected generators and large power stations in pre-commissioning, interconnectors, and distribution-connected generators contracted with National Grid.

[10] If the user terminates their connection, then they will face a much larger liability closer to the investment made by the licensee up until point of termination.

a separate bank account until the project either connects (where it is returned to the user) or terminates.

1.26. The connecting customer's liability depends on its contribution to "attributable" and "wider" works. The attributable liability is based on the cumulative expenditure on the relevant schemes listed in the user's Connection Agreement. The attributable cancellation charge is also adjusted for the percentage of spend that could be "reused" if the project is terminated, and the proportion of the scheme that the connecting customer can use if exporting at their full TEC. The customer can "fix" on an attributable profile, derived from the TO's estimated spend profile for the relevant schemes. Once the customer has fixed on a given profile this will cease to be updated. Post the "trigger date" the customer will pay an increasing percentage of the estimated profile that they fixed on. This decouples user commitment from the TO's actualised spend profile. If a fixed customer terminates they will not be reconciled to the actual spend incurred by the TO – this could be higher or lower than their fixed value.

1.27. The wider liability is based on wider transmission reinforcement needed to maintain and increase network capability. This is applicable from three years before the financial year of connection and increases closer to commissioning. This can be reduced on, for example, confirmation of planning consents to reflect the reduced risk of termination. For connection assets and one-off works where the user still has an outstanding balance, the remainder must be secured against even post connection. There are no adjustment factors applied post connection – the balance is secured against at 100% of the outstanding value.

1.28. Transmission-connected demand (and DNOs) also pay securities but based on the "Final Sums" methodology which generally requires more upfront payments than the user commitment methodology.

Distribution use of system charges

Arrangements for customers connected at low voltage (LV) and high voltage (HV)

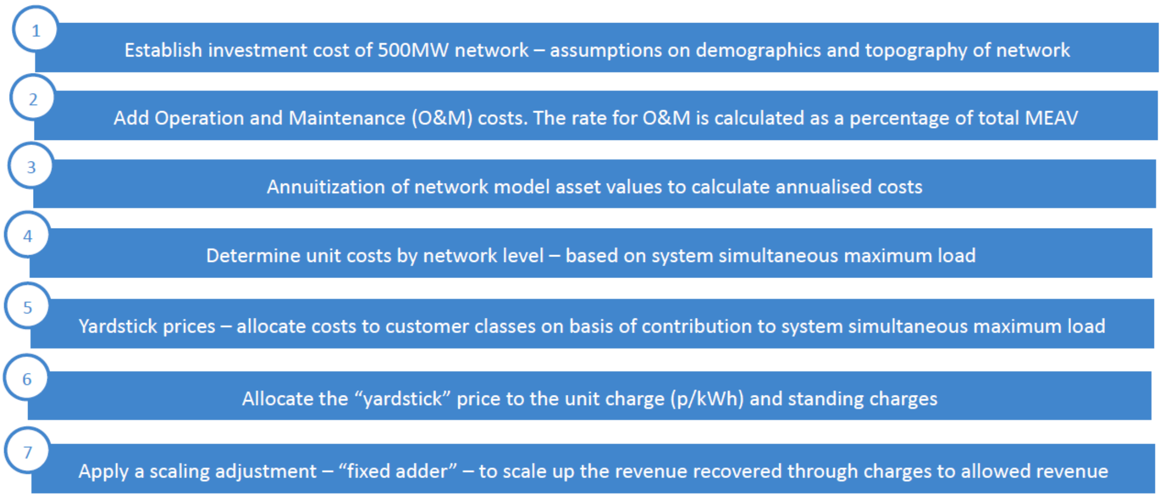
Model used to calculate forward looking DUoS charges – LV and HV connected

1.29. The Common Distribution Charging Methodology (CDCM) is used for users connected at the LV and HV levels. The CDCM calculates DUoS charges for these customers based on a 500MW incremental Distribution Reinforcement Model, also known as the "500 MW model". The 500 MW model is an example of a "Total Service Long Run Incremental Cost model". This model calculates the investment cost for a new, hypothetical 500MW network,[11] with operation and maintenance costs added, with the costs being annuitized and costed by voltage level.[12] The model does not include generation. As the network model is rebuilt with a new optimised asset mix every year, CDCM charges capture and signal both reinforcement and replacement costs.

1.30. Customer charges are calculated based on their voltage level and customer class. Costs are split between user groups based on their contribution to **simultaneous** maximum demand (typically for unit charges) and aggregate maximum demand (typically for fixed and capacity charges).[13]

1.31. The intent behind this methodology is that the 500MW network model represents a new Grid Supply Point (GSP) with a mix of assets and loading that is reflective of the whole distribution network licence area (also known as a GSP group). The subsequent calculations attribute the costs of developing and maintaining this network to particular customer classes. A summary of the steps is shown below.

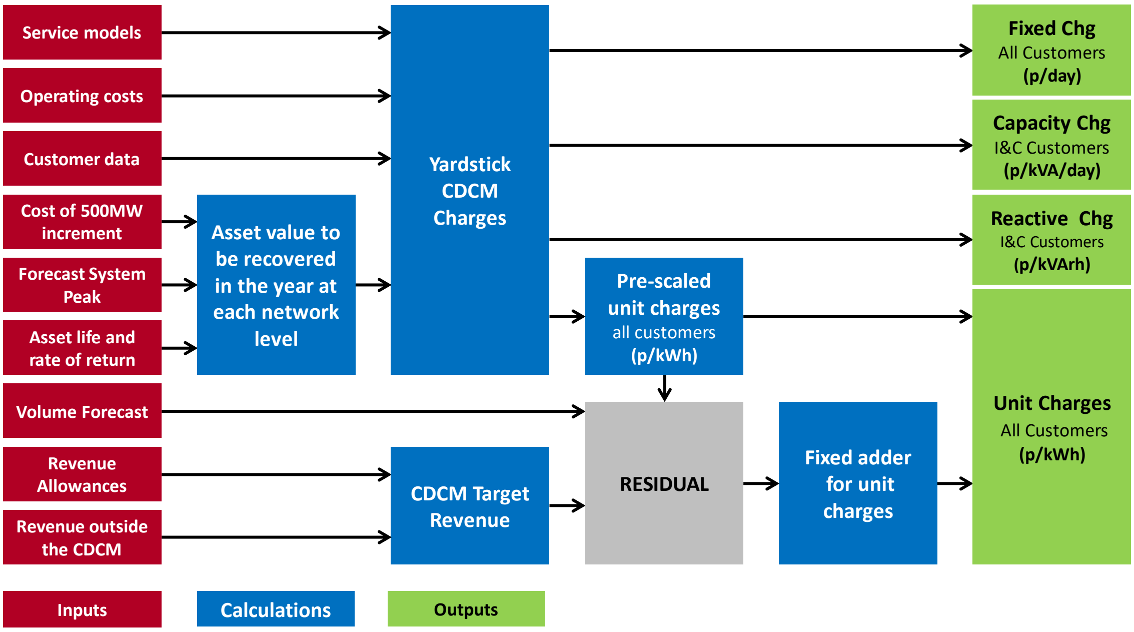
Figure 1: Steps involved in calculating DUoS charges[14]



Source: CEPA (Cambridge Economic Policy Associates)

[11] In the CDCM, this is labelled the "Gross asset cost by network level". 500 MW is roughly the demand at a typical grid supply point.
[12] Costs, as described in Distribution Connection and use of System Agreement (DCUSA), include asset cost, transmission expenditure, direct operating costs, network rates and a portion (60%) of indirect costs.
[13] Aggregate maximum demand is calculated by aggregating agreed import capacities for half hourly settled users and estimated capacities for non-half hourly settled user groups.
[14] MEAV is Modern Equivalent Asset Value in £.

Figure 2: Diagrammatic representation of CDCM charge calculation



Source: Northern Power Grid

1.32. The annuitisation of network model asset values over an asset lifetime of 40 years according to their MEAV, steps 3 and 4, determines the £/kW/year figure corresponding to amortisation and return on capital for assets.[15]

1.33. DUoS charges vary by DNO region. Within each DNO region, there are no locational charges for CDCM customers (although the charges do vary by voltage level, but only based on the generic 500MW model for that DNO region). They also do not take direct account of generation, with charges for generation calculated on the assumption that generation will always reduce DNOs' costs relating to serving demand. A consequence of this is that CDCM distributed generators always receive DUoS credits, even if they are driving network costs (eg in "generation-dominated areas", where exports up through the distribution network are driving network costs).

Network charging design for LV and HV connected customers

1.34. In our Locational cost models discussion note, we describe the process for allocating costs to different customer groups using the CDCM for customers connected to the LV and HV distribution networks and the extra high voltage (EHV) distribution charging methodology (EDCM) for customers connected at EHV. This section explains how the costs allocated to different customer groups under the CDCM are recovered through network charges. CDCM customers are split into groups based on the type of customer and voltage

[15] Source: https://www.dcusa.co.uk/SitePages/Documents/DCUSA-Document.aspx

of connection and incur charges; which comprise a mix of unit rates, fixed charges, capacity charges and reactive power charges. We describe these below.

Unit rates (p/kWh)

1.35. There are three unit rates (red, amber and green), which are allocated to different periods of the day (known as time bands) and vary depending on the DNO's estimate of how likely the network is peaking. Under the current methodology, non-half hourly (NHH) settled customers only face a single unit rate, which is applied to all consumption, although this will change, once DCP268[16] comes into effect, which is expected to be from 1 April 2021.

1.36. For generation customers, the unit rates are credits, reflecting the assumption at the time the CDCM was developed that generation always provides a network benefit by offsetting demand.

Fixed (p/MPAN/day)

1.37. Sole use asset charges are based on service models, representing typical assets for a customer category. However, the assets are deemed to be fully covered by customer contributions so the fixed charge recovers the DNOs' assumed operating and maintenance costs associated with the service model. For small users, the fixed charge also includes a capacity-related charge, which is calculated by multiplying the p/kVA/day by the estimated maximum load of a customer category.

1.38. Under the current CDCM, residual charges are recovered as a fixed adder on unit rates, rather than through fixed charges. However, depending on the outcomes from our Targeted Charging Review Significant Code Review (SCR), the fixed charge may also recover residual charges in the future, in order to ensure it does not send signals to customers to change their behaviour.

Capacity (p/kVA/day)

1.39. Under their terms of connection, some non-domestic customers are required to agree the capacity they need with their DNO, which they are charged for. The amount of the capacity charge is calculated by applying "standing charge factors", which determine

[16] https://www.ofgem.gov.uk/system/files/docs/2019/04/dcp268_d.pdf

the percentage that unit rates are reduced by, with the revenue recovered through capacity charges instead. Capacity-based charges generally apply to near-to-site (ie lower voltage levels), while the remaining costs are recovered through volumetric charges.

1.40. If customers exceed their agreed capacity, they will be required to pay an "exceeded capacity" charge, which does not include a discount to reflect customer contributions to assets, which is applied to capacity charges.[17]

Reactive power (p/kVArh)

1.41. Larger half hourly (HH) settled customers face reactive power charges, which apply to reactive power that is in excess of a power factor of 0.95 and is calculated using adjusted unit rates and average kVArh by kVA, which is calculated by the DNO. In 2016, we approved DCP222,[18] which exempted generators from paying reactive power charges when they are responding to a request by a DNO.

1.42. The following table identifies the network charges each customer category incurs, including the impact of the DCP268 changes, as referred to above.

Table 1: Charging elements incurred by each customer category

Tariff	**Unit rate 1** p/kWh	**Unit rate 2** p/kWh	**Unit rate 3** p/kWh	**Fixed charge** p/MPAN/day	**Capacity charge** p/kVA/day	**Exceeded capacity charge** p/kVA/day	**Reactive power charge** p/kVArh
Domestic aggregated[19]	Red	Amber	Green	√			
Domestic aggregated (related MPAN)	Red	Amber	Green				
Non-domestic aggregated	Red	Amber	Green	√			
Non-domestic aggregated (related MPAN)	Red	Amber	Green				
Unmetered supplies	Black	Yellow	Green				
LV site specific	Red	Amber	Green	√	√	√	√
LV Sub site specific	Red	Amber	Green	√	√	√	√
HV site specific	Red	Amber	Green	√	√	√	√

[17] The change to remove the discount was introduced under DCP161, which we approved in 2014: https://www.ofgem.gov.uk/sites/default/files/docs/2014/10/dcp161_d_0.pdf
[18] https://www.ofgem.gov.uk/system/files/docs/2016/08/dcp_222_d.pdf
[19] For the aggregated tariff options, the DNOs' bill suppliers for the aggregated consumption of the customers in each customer class, rather than on an individual customer basis.

Tariff	Unit rate 1 p/kWh	Unit rate 2 p/kWh	Unit rate 3 p/kWh	Fixed charge p/MPAN/day	Capacity charge p/kVA/day	Exceeded capacity charge p/kVA/day	Reactive power charge p/kVArh
LV generation aggregated	Red	Amber	Green	√			
LV Sub generation aggregated	Red	Amber	Green	√			
LV generation site specific	Red	Amber	Green	√			√
HV generation site specific	Red	Amber	Green	√			√
LV generation site specific no RP	Red	Amber	Green	√			
LV Sub generation site specific no RP	Red	Amber	Green	√			
HV generation site specific no RP	Red	Amber	Green	√			

Arrangements for EHV connected customers

Model used to calculate forward looking DUoS charges – EHV and HV sub connected

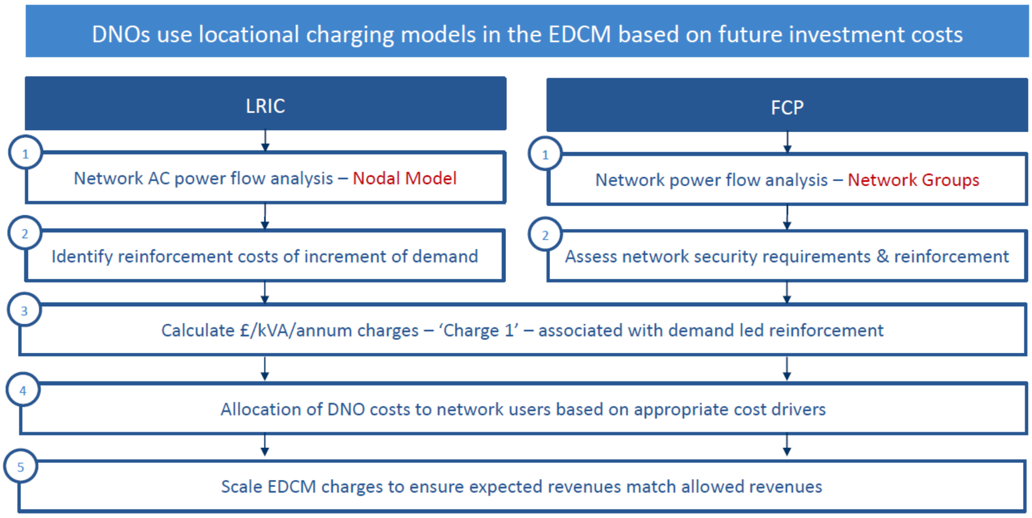
1.43. The **EDCM**[20] applies to users connected at (or above) 22kV, or connected into a substation where the primary infeed is at or above 22kV. DNOs can choose one of two methods to use for each licence area - either the Long Run Incremental Cost (LRIC) method or the Forward Cost Pricing (FCP) method. Both methodologies are predicated on the assumption that incremental growth in load (generation and load for LRIC) is what drives forward-looking costs, ie – unlike CDCM, EDCM does not account for replacement costs.

1.44. The purpose of the load flow analysis is to determine the utilisation of the network under Normal Running Arrangement (Base Case Analysis) and N-1 Contingency condition (Contingency Analysis). Both LRIC and FCP use load flow analysis to model constraints. However, the models treat the reinforcement needs estimation differently, and therefore produce different results.

[20] Models are available here: https://www.dcusa.co.uk/SitePages/Documents/DCUSA-Document.aspx

1.45. Six of the DNO licence areas use the FCP variant, as described in Schedule 17 of the DCUSA. Eight of the DNO licence areas use the LRIC variant, as described in Schedule 18 of the DCUSA.[21]

Figure 3: Overview of EDCM modelling process



Source: CEPA

<u>Forward cost pricing</u>

1.46. The FCP methodology separates the network into a number of "Network Groups". The FCP demand price is calculated by assessing network reinforcement cost to support a maximum of 15% demand increment for each network group over the next 10 years. In practice, the distribution network companies use the demand growth projections from their Long Term Development Statement (LTDS) submissions which set out their network development plans. The outputs of FCP are sensitive to the growth projections set out in the LTDS.

1.47. Contingency analysis is undertaken (in line with planning for network security standards) to identify the assets in each network group that will require reinforcement. This is achieved using load flow studies. The objective of the contingency analysis is to identify the branches that require reinforcement and to determine the time (years) to reinforcement.[22]

[21] CEPA user guide, https://www.dcusa.co.uk/Documents/EDCM-LRIC-v3_20181016.pdf
[22] The Contingency Analysis is based on all credible outages that could affect the DNO Party's Distribution System. Both N-1 Events and where necessary, N-2 Events are modelled and the consequential network actions required to meet the security of supply requirements of ER P2/6 and the agreed level of security of supply to individual Connectees.

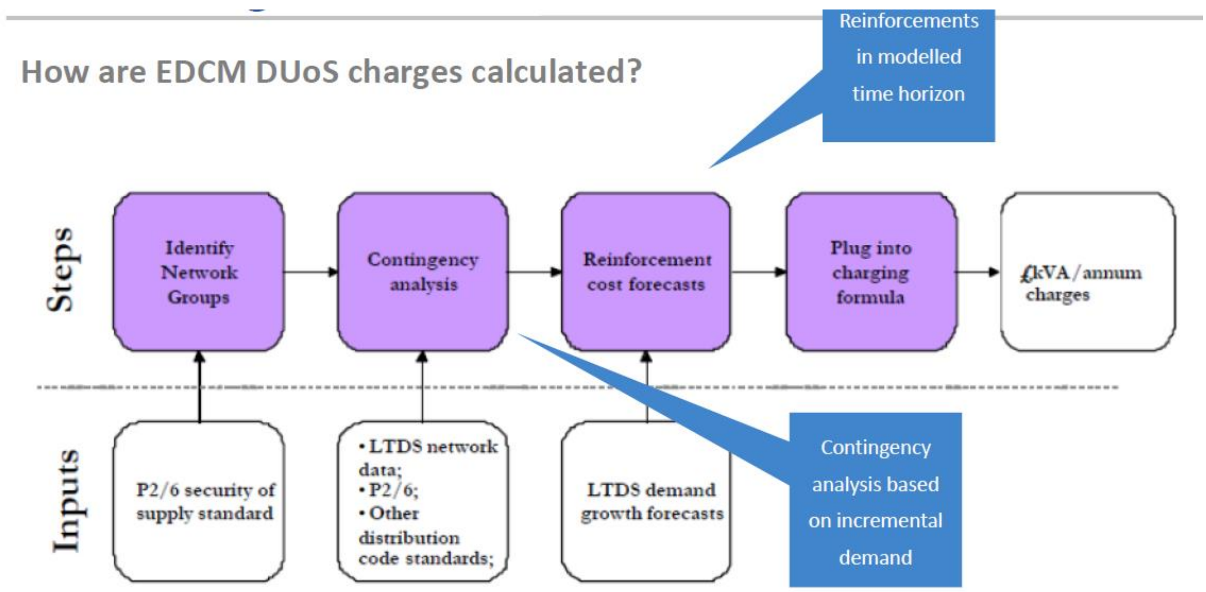
1.48. The potential reinforcement cost is calculated and averaged at each voltage level within the same network group, such that the total revenue recovered equals to the forecasted reinforcement cost plus a certain level of investment return. The FCP charges within a network group are the same for all the customers connected within that group. A network group is either:

- 132 kV and similar circuits (a "level 1" group)
- 132 kV/33 kV and similar substations with 33 kV and similar circuits (a "level 2" group)
- 132 kV/11 kV or 33kV /HV primary substations (a "level 3" group)

1.49. Each group may also have "parent group" associated with it. The parent group of a parent group is referred to as a "grandparent group". For example, the parent group of the level 3 group of 33 kV/HV substations would be the level 2 group above it, and its grandparent group would be the level 1 group above that.

1.50. The reinforcement cost forecasts are modelled and plug into the charging formula. The outputs of the FCP power flow method are a £/kVA/year "Charge 1" for every network group defined in the DNO's network.

Figure 4: FCP – charging formula increases charge level as time to reinforcement approaches



Source: CEPA

1.51. The model groups nodes together into network branches, under which all users pay the same charges. The reinforcement need for the branches is determined by the 10 year forecasts in the LTDS.

1.52. Due to the fact that the FCP groups nodes together in branches, the resulting prices do not send locational signals within branches. There is theoretical evidence that resulting prices should be less volatile than that of the LRIC model due to this grouping effect. However, in practice, there is also contrasting evidence that FCP can result in more volatility given that the FCP approach is more subjective.

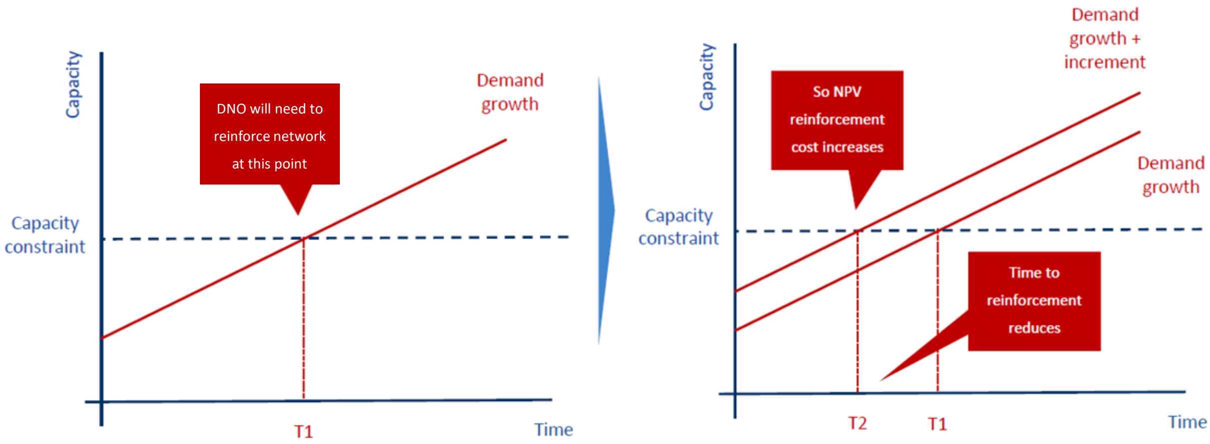
Long Run Incremental Cost

1.53. The LRIC methodology calculates nodal incremental costs, which represent the network reinforcement costs that driven by the addition of demand or generation at each network node. A forecast of network reinforcement requirements is made on the basis of a 1% annual load growth rate assumption (see Figure 5). The NPV of the cost of the reinforcement is then calculated. Next, a second forecast is made which includes the 1% demand growth plus a 0.1MW increment of demand or generation at a node. The NPV of the cost of reinforcement is calculated and capped to the annuitised rate over a 40-year period.

1.54. The LRIC of demand or generation is estimated by subtracting the incremental NPV from the initial NPV estimate. AC power flow analysis is used as the basis for how network costs are allocated, based on how a change in connectee behaviour will affect the network.

1.55. The outputs of the LRIC power flow method are a local £/kVA/year "Charge 1" and a remote "Charge 1" for each location in the model, where the local charge refers to the local network and the remote charge refers to higher voltage levels. In addition, each LRIC location may have a "linked location", in order to define clusters of up to eleven locations which are processed together.

Figure 1: LRIC is based on the change in NPV reinforcement cost, caused by the change in time needed until reinforcement is required



Source: CEPA

1.56. The LRIC method recovers a smaller proportion of the total recoverable revenue than the FCP method does. The LRIC model is fully nodal (using the load flow analysis described above), and the need for reinforcement is determined using a notional demand growth of 1% per year.

Network charging design for EHV connected customers

1.57. EDCM customers all face individual charges, which are calculated based on the arrangements specific to their connection. Although the values differ for each customer, they will all be a combination of the following charges, applicable to import and export volumes (note that not all customers face every charge):

- Super red unit charge (p/kWh) – reflects the remote element of "Charge 1" described above for demand customers and local and remote elements of "Charge 1" for generation customers. Each DNO designates its own super red time period during which customers will be charged for consumption or receive credits for export.

- Fixed charge (p/day) – relates to direct operating costs for sole use assets and network rates.

- Capacity charge (p/kVA/day) – reflects the local element of "Charge 1", operating costs, network rates and scaling for demand customers, and operations and maintenance costs and scaling for generation customers. The capacity charge applies as a charge for both generation and demand customers.

- Exceeded capacity charge (p/kVA/day) – this rate is the same as the rate charged for capacity.

Transmission use of system charges

Model used to calculate TNUoS charges

Model for calculating transmission use of system charges

1.58. Tariff calculation for users at the transmission level is based on the Direct Current Load Flow Investment Cost Related Pricing model, also known as the Transport and Tariff model, which covers the whole of GB. It was first introduced in 1993/94 and has developed since then, with major changes implemented following Project Transmit.[23] It is a spreadsheet based implementation of a DC load flow model. The rationale behind the model is that efficient signals are sent to users when the users' charges reflect the incremental cost of using the network. The costs are defined as the cost of investing in and maintaining the network to meet the security standards.

1.59. The TNUoS charge comprises of two separate elements. These are the locationally varying element (including local circuit and wider charge components) derived from the Transport model, which signals forward-looking costs, and a residual element related to the provision of revenue recovery. The "reference node" is used to help derive the TNUoS locational charges for different users and areas, described further at paragraph 1.62 below. We decided to include the reference node within the scope of the SCR. We describe the TNUoS methodology in more detail below.

<u>Calculating incremental costs</u>

1.60. The Transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system. It does this by modelling the transmission system as over 900 "nodes" (basically junctions where different parts of the network meet, such as a substation). These nodes are connected by over 1400 "circuits" (transmission lines or cables that carry power).

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[23] https://www.ofgem.gov.uk/publications-and-updates/project-transmit-decision-proposals-change-electricity-transmission-charging-methodology

1.61. For generation, the charge at each node of the network is based on the cost of adding an increment of 1 MW at that node. The corresponding demand for the 1MW generation increment is spread across all demand nodes (in proportion to their demand) – this is known as a "distributed demand reference node". This change in flow on each circuit is then measured and multiplied by the length of circuit to give a figure in MWkm. For demand charges, the same process is run, but by adding a 1 MW increment at each demand node (and reducing demand by 1MW overall across all demand nodes), and calculating the resulting length of flow on each circuit.

1.62. The cost output is that of moving an additional MW of power, either generation or demand (depending on whether the model is calculating generation or demand tariffs). The cost assumption in the model centres around a benchmark for the cost of 400kV overhead line, which is updated at the start of each price control. The benchmark cost of the 400kV Overhead (OH) line includes the cable, pylons and conductor, however, it excludes road crossing and land costs. The costs are annuitized, and an uplift for Operation and maintenance (O&M) is applied. Where parts of the network use transmission assets other than 400kV overhead lines (eg other rated lines, or underground cables), the costs are adjusted using an expansion factor.

1.63. This methodology estimates costs on the premise that all incremental flows will add costs to the network. It does not take into account spare capacity, and the fact that in areas where spare capacity network reinforcement may not be needed for some years. Because of this, it can be described as an "ultra long run" signal, based on the premise that in the very long-run the network will either need reinforcement and/or existing network assets will need replacing. Alternatively, it could be described as an "allocative" signal in that it allocates users' incremental contribution to existing network costs. In this respect, it is more similar to the CDCM than the EDCM, which were both described earlier in this note.

<u>The peak security and year-round backgrounds</u>

1.64. The reforms brought in by Project Transmit recognised that system costs are no longer driven just by meeting peak demand, but also in making sure there is also an efficient level of capacity to carry power year-round, such as that from renewables.

1.65. The model process described above is run using two backgrounds with different inputs to simulate the effect of these additional flows at peak time (the peak security background) and throughout the year (the year-round background). Incremental flows are modelled based on these two backgrounds.

1.66. Individual circuits are assigned to one of these backgrounds depending on which of the backgrounds has the biggest impact on that circuit. The impact of the changes in flows on circuits assigned to the peak security background make up the peak security element of the wider locational TNUoS charge. The impact of the changes in flows on circuits assigned to the year round background make up the year round element of the wider locational TNUoS the charge.

1.67. The model has scaling factors (relating to the type of generation and the need on an asset to meet demand) that set out the amount of network needed, and these are outlined in the SQSS (they are often referred to as SQSS scaling factors). The effect of adding or removing a MW is also likely to be different in different areas as it will depend on the nodes, circuits, generators, size of demand etc. Adding the same amount of generation from the same type (and so with the same scaling factor) will result in the same cost.

1.68. However, one thing that is treated differently is distributed generation (DG) when it is treated as negative demand. Instead of being scaled, removing the generators capacity from the demand (effectively netting off their output with the demand from the area) will have a full, unscaled impact on the system, so in an area where demand reduction or generation can reduce the MWkm on the system, DG (when treated as negative demand) has a bigger positive impact on the system because that demand reduction "goes further" than the corresponding generation increase which is scaled if that same DG was treated as demand. In an area where demand reduction or additional generation increases the MWkm on the system, the impact of the DG would again be greater as unscaled.

1.69. The resulting prices are zonal rather than nodal. For generation, the nodes are grouped together into zones where the node groupings are geographically and electrically proximate, and the difference between prices is not greater than £2/kW. The grouping is done at the start of a price control, and can be adjusted at the discretion of the ESO within the price control. There are currently 27 different generation pricing zones which are set out in Figure 8 in the annex to this note. For demand pricing, the zones are the 14 DNO regions, which are set out in Figure 9.

TNUoS network charging design

1.70. The existing transmission charging arrangements provide signals for using the network for parties carrying out a number of roles. Broadly, the demand regime covers:

- larger users who face half-hourly demand charges, and

- smaller users that face volumetric charges.

1.71. For generators, the arrangements apply differently to the following broad categories of users:

- Transmission-connected generation (TG), in which we also include larger distributed generation with installed capacities above 100MW (Large DG), which face transmission generation charges;
- Small (<100MW) distribution-connected generation (SDG), who face transmission charges as inverse demand, with their output netting off demand in their region; and
- Behind the meter generation (BTMG), also known as onsite generation (OSG) and demand side response (DSR), who also face transmission charges as inverse demand, with their output or demand reduction netting off demand on their sites. When exporting from their site, BTMG faces same signal as SDG.

Transmission network charging design for demand customers

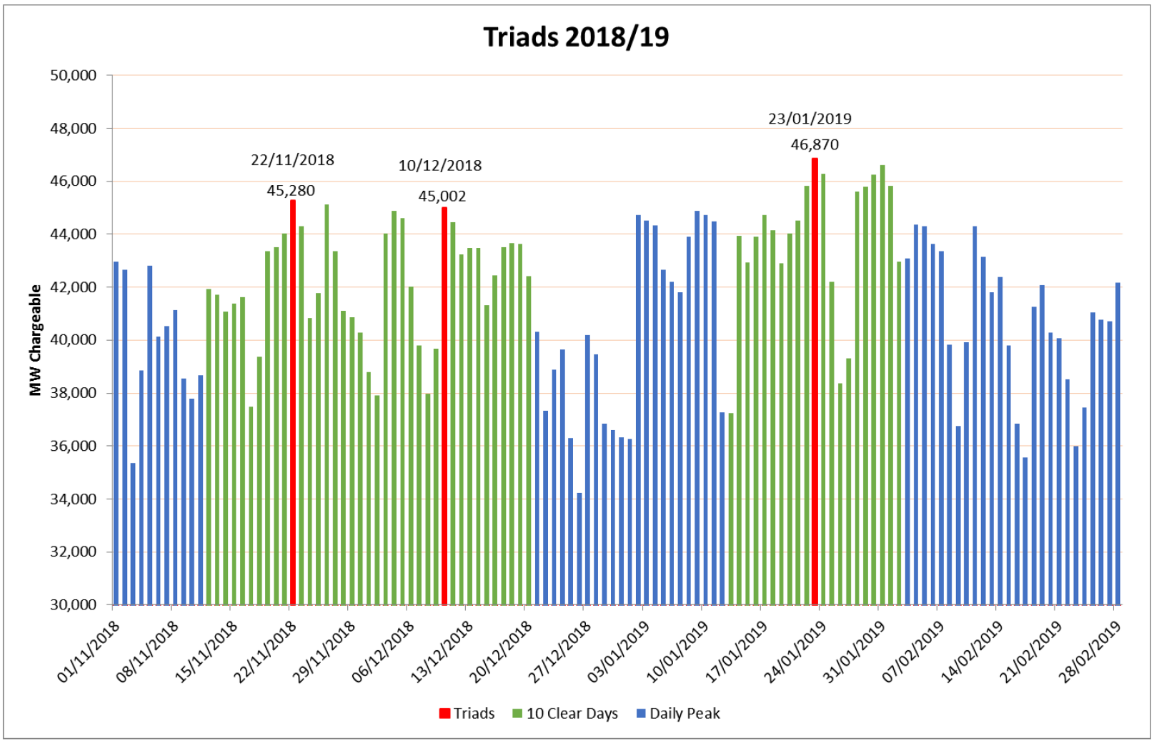
1.72. There are different charging methodologies that apply for HH settled and NHH settled customers. We describe the differences below.

<u>HH demand customers</u>

1.73. Suppliers are charged according to the aggregate demand of their HH metered customers (measured in MWh) for average demand over the three Triad periods each year. Triads are defined as the three half-hours with the highest net system demand, between November and February (inclusive), separated by at least ten clear days. This is forecast in advance by suppliers at the demand region level and reconciled against actual consumption.

1.74. The following chart identifies as red bars the Triad periods for the 2018-19 charging year, which were on 22 November, 10 December and 23 January. The Triad times were from 5:30 – 6:00pm for the first two dates and from 6:00-6:30pm for the last date.

Figure 6: Triad dates for 2018-19 charging year



1.75. There has generally been a high level of predictability at what time of day Triad periods occur – in most years, it is during the early evening period (5pm, 5.30pm or 6pm). On the other hand, there is less certainty on what days the Triad periods will occur, as they can change substantially from year to year. Historically, the first Triad period has typically varied between mid-November to mid-December, and the last Triad has typically varied over a wider timespan of between early January and late February.

1.76. The tariffs are levied as £/kW and include a locational component, which is calculated by the transport model as described above and varies for 14 demand zones (which correspond to the 14 DNO licence areas – see figure 10 below), and a residual component to ensure the correct amount of revenue is recovered.

1.77. As a result of CMP264[24] and CMP265,[25] the above HH charging methodology applies to gross demand and embedded exports, where the gross demand tariff is applied to HH gross demand (resulting in a payment from the supplier) and the embedded export tariff is applied to HH exports (resulting in a payment to the supplier).

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[24] https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc/modifications/cmp264-embedded-generation-triad-avoidance
[25] https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc/modifications/cmp265-gross-charging-tnuos-hh-demand-where

1.78. In 2016, we approved CMP266,[26] which modified the CUSC to provide that small users who elect to move to HH settlement would continue to be charged under the NHH arrangements described below for customers in Measurement Classes F and G. This change was introduced to address an issue where a customer could be double charged for a period of the year during which they moved and sought to remove this as a barrier to customers choosing to be electively HHS. The change expires on 31 March 2020 and the ESO has raised CMP318[27] to extend this until 31 March 2023, which is currently progressing under the CUSC modification process.

<u>NHH demand customers</u>

1.79. Currently, NHH metered and electively HH settled customers are settled on a NHH basis, which means the NHH TNUoS demand charging methodology applies to them. Under this methodology, suppliers are charged for their customers' annual consumption during the 4-7pm period. This is forecast in advance by the supplier at the demand region level and reconciled against actual consumption. Because customers are charged based on a profiled basis (ie using generic consumption profiles to estimate how much of a customer's annual consumption is at peak times), they do not receive any incentive to reduce their peak consumption.

1.80. Charges for NHH settled customers are based on their annual consumption between 4-7pm, calculated in p/kWh. The tariff is charged in p/kWh. NHH tariffs are set by taking the revenue required from each of the 14 demand zones less the revenue recovered from gross HH charges and dividing it by the forecasted NHH demand volumes in each zone.

Transmission network charging design for generation customers

1.81. We briefly describe the arrangements for generation charges below. There are two generation methodologies, with one for transmission connected customers and distribution connected customers with generation equal to or greater than 100MW (large generation) and a second methodology for distribution connected customers with generation less than 100MW (SDG).

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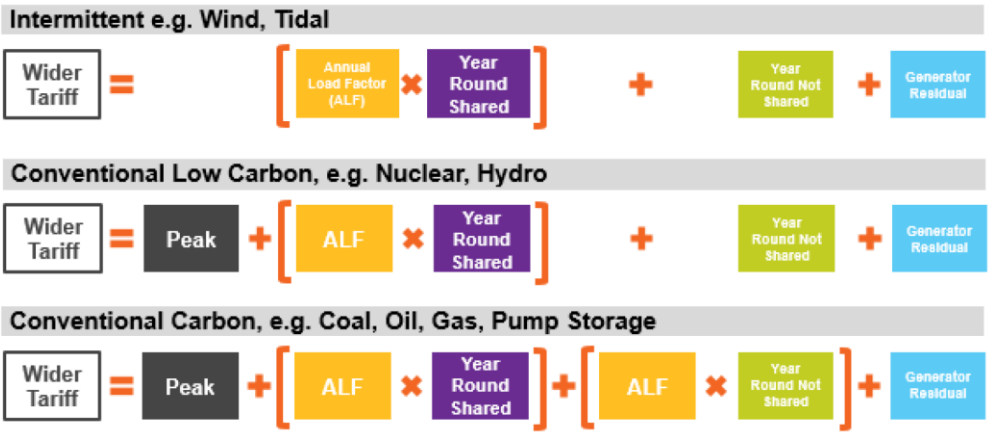
[26] https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc/modifications/cmp266-removal-demand-tnuos-charging
[27] https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc/modifications/maintaining-non-half-hourly-nhh-charging

Large generation charges

1.82. Charges for large generators comprise a mix of the following elements:

- Wider tariff – this component is charged, based on the greatest amount of TEC (equivalent to an agreed capacity) the customer holds during the year. The tariffs are set as £/kW by the transport and tariff model, as described above, and differ between the 27 generation zones (see Figure 9 below). The wider tariff also varies, depending on the type of generator, as illustrated in Figure 7.
- Local substation tariff – applies only to transmission-connected generators that are directly connected to a substation that is defined as a Mains Interconnected Transmission System (MITS) node.[28] The tariff is set on a £/kW basis.
- Onshore local circuits tariff – applies only to transmission-connected generators connected to a non-MITS node and reflects the flows on circuits between the connection and the MITS. The tariff is set on a £/kW basis.

Figure 7: Illustration of how the wider tariffs are calculated for different generation technologies



Source: ESO TNUoS in 10 minutes

Small distributed generation charges

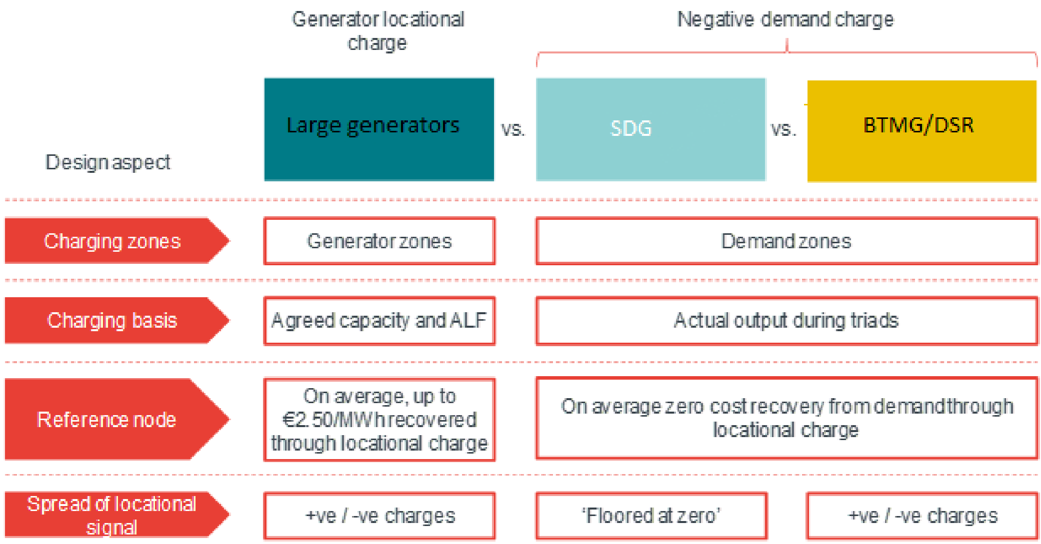
1.83. Small distributed generators can receive a payment known as the Embedded Export Tariff, which is calculated based on their average HH metered generation export over the three Triad periods. The tariff is set in £/kW and comprises of a demand locational component, which is taken from the Transport model and varies by demand region, an

[28] A MITS node is a Grid Supply Point connection with two or more transmission circuits connecting at the site or a node with more than four transmissions circuits connecting at the site

AGIC,[29] which is set at the start of the price control period (increasing by RPI each year), and a residual component. Their generation output during the Triad charging periods reduces the net demand within their GSP.

1.84. The below graphic summarises some differences between large generators, SDG, and BTMG/DSR.

Figure 8: Charging signals. Source: Frontier Economics



1.85. A summary of each user group's relationship with the transmission charging regime is presented below.

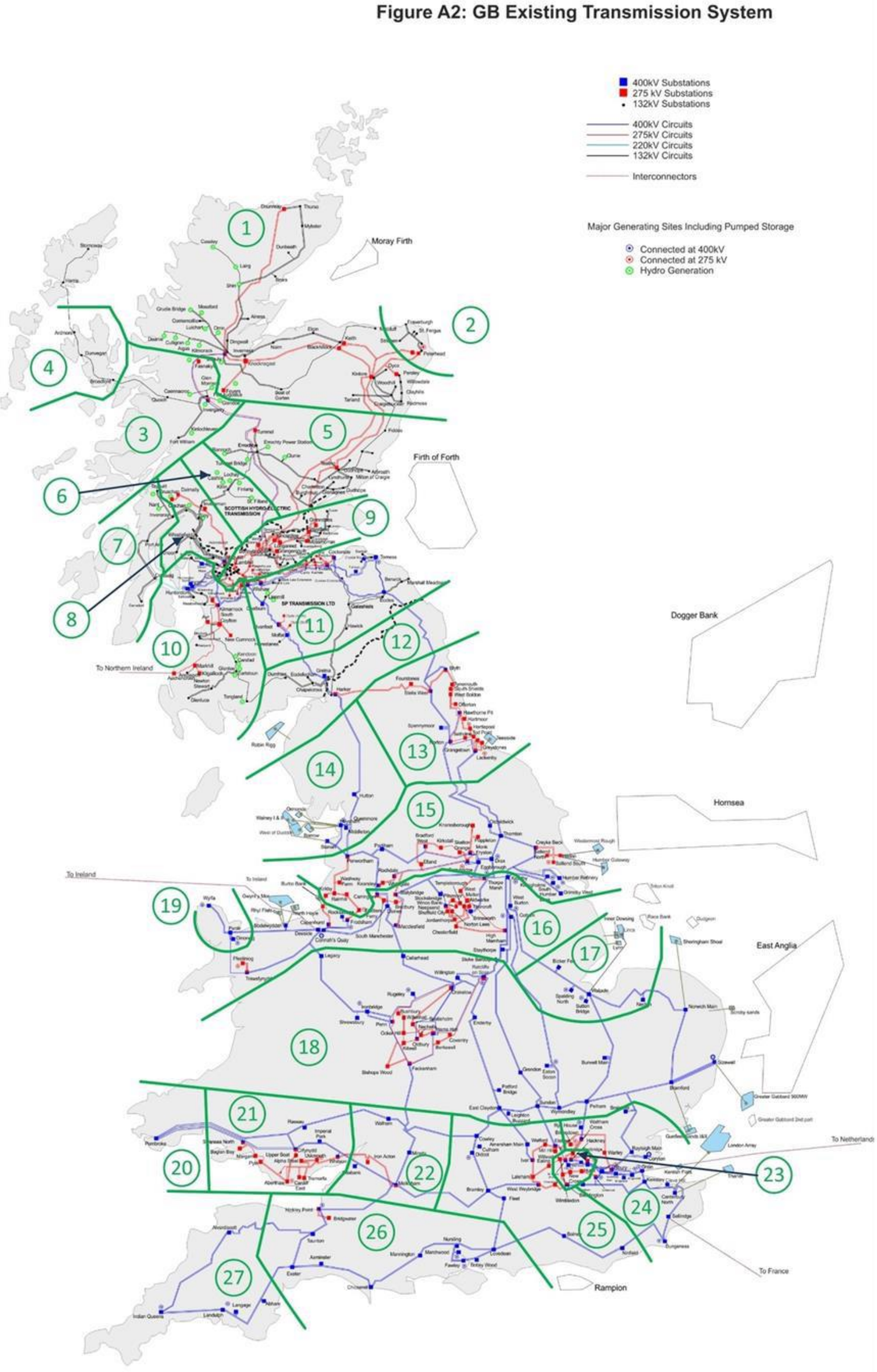
Table 2: Summary of each user group's relations with the transmission charging regime

User	Large generators	Demand	Small distributed generation charges and BTMG
Positive Demand Charge Zone (Typically Southern zones)	Face generation charges - receive a payment based on their held capacity (TEC), their technology type and load factor.	Face demand charges - pay a positive charge, and therefore faces an incentive to reduce their demand during triads.	Face the inverse of demand charges - receive a payment if they are generating during the triads.
Negative Demand Charge Zone	Face generation charges - pay a	Face demand charges - receive a payment	Face the inverse of demand charges -

[29] AGIC = avoided grid supply point infrastructure credit

User	Large generators	Demand	Small distributed generation charges and BTMG
(Typically more Northern zones)	positive charge based on their held capacity (TEC), their technology type and load factor.	for increasing their demand during the triads.	small distributed generation would pay to generate during the triads, were it not for the charging cap. BTMG face a signal to avoid generation at triads.

Figure 9 – Electricity transmission generation zones30



30 https://www.nationalgrideso.com/document/137351/download

Figure 10 – Electricity transmission demand zones