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CUSC - SECTION 14

CHARGING METHODOLOGIES

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Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.1 Transmission Network Use of System ~~c~~Charges reflect the cost of installing, operating and maintaining the transmission system for the ~~TO~~ Transmission Owner Activity function of the Transmission Businesses of each Relevant Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between ~~c~~Connection ~~s~~Sites and to provide transmission system security.

14.14.2 The ~~A Maximum~~ Allowed Revenue ~~(MAR)~~ defined for these activities ~~and those associated with pre-vesting connections~~ is ~~set by~~agreed with the **Authority** at the time of the Transmission Owners' price control review for the succeeding price control period. The Allowed Revenue can be adjusted during the Price Control period. **Transmission Network Use of System Charges** are set to recover the Maximum ~~Allowed~~ Revenue.~~ as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).~~

For the purpose of calculating demand tariffs only, forecast inputs for revenue and the demand charging base will be determined 15 months before the **Financial Year** and subsequently reconciled and recovered through succeeding **Financial Years** once revenue requirements are known.

14.14.3 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.4 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

14.14.5 In April 2004 The Company introduced a DC Loadflow (DCLF) ICRP based transport model for the England and Wales charging methodology. The DCLF model has been extended to incorporate Scottish network data with existing England and Wales network data to form the GB network in the model. In April 2005, the GB charging methodology implemented the following proposals:

i.) The application of multi-voltage circuit expansion factors with a forward-looking Expansion Constant that does not include substation costs in its derivation.

ii.) The application of locational security costs, by applying a multiplier to the Expansion Constant reflecting the difference in cost incurred on a secure network as opposed to an unsecured network.

iii.) The application of a de-minimus level demand charge of £0/kW for Half Hourly and £0/kWh for Non Half Hourly metered demand to avoid the introduction of negative demand tariffs.

iv.) The application of 132kV expansion factor on a Transmission Owner basis reflecting the regional variations in network upgrade plans.

v.) The Company will set tariffs in a manner so that the locational varying element, as established by the DCLF ICRP model and, where appropriate, local substation and local circuit charges, are levied on all Generator and Demand Users. Any remaining Transmission Owner revenues will be recovered from demand only in a non-locational manner through a residual charge.

vi.) For the purpose of compliance with the Limiting Regulation in the context of setting limits on the annual charges paid by generation The Company will exclude Charges for Physical Assets Required for Connection when calculating the total amount to be recovered from Generators (GCharge (Forecast)).

vii.) If having applied the exclusion of Charges for Physical Assets Required for Connection The Company identifies that an adjustment to TNUoS Charges is required to remain compliant with the Limiting Regulation then an Adjustment Tariff will be applied to all Generators in the following circumstances.

i.) The Adjustment Tariff will be applied if The Company identifies that either:

a. Annual average TNUoS charges payable by Generator Users will fall below €0/MWh

OR

b. Annual average TNUoS charges payable by Generator Users will exceed €2.50/MWh adjusted by a risk margin to allow for error in tariff setting.

ii.) Where annual average TNUoS charges to Generators are positive under the GCharge (Forecast) the Adjustment Tariff will be applied if the Adjustment Revenue is less than £0. The Adjustment Revenue is expressed as:

$$AdjRevenue = (GO * ((CapEC * (1 - y)) * ER)) - GCharge(Forecast)$$

i.) Where annual average TNUoS charges to Generators are negative under the GCharge (Forecast) the Adjustment Revenue will be the difference between £0 and the total recovered from Generators. The Adjustment Revenue will be expressed as:

$$AdjRevenue = 0 - GCharge(Forecast)$$

ii.) The total adjusted revenue expected to be recovered from Generators (AdjGenRev) through TNUoS tariffs can therefore be expressed as:

$$AdjGenRev = GCharge(Forecast) + AdjRevenue$$

iii.) The error margin used in calculating TNUoS tariffs for the **Financial Year** is expressed as:

y = (1+ ErrorGenRev) / (1 - ErrorGO) -1

iv.) Where:

y = error margin expressed in %.

ErrorGenRev = the highest absolute percentage error in generation revenue collection, adjusted by systemic error, from the past 5 full years (year t-6 to t-2 inclusive). Systemic error is the average of %error in generation revenue collection for the past 5 full years. Systemic error can be positive or negative.

ErrorGO = the highest absolute percentage error in generation TWh outputs, from the past 5 full years (year t-6 to t-2 inclusive).

v.) The Company will use the latest OBR Forecast of £/€ exchange rate published prior to the 31st October in the year preceding the relevant **Financial Year** to convert average annual TNUoS charges payable by Generators in the GCharge (Forecast) to a comparable value for the purposes of assessing compliance with the Limiting Regulation.

vi.) The Adjustment Tariff used in the calculation will be either:

1. a negative £/kW tariff that reduces annual average TNUoS charges to Generators to below the risk adjusted upper limit of the Limiting Regulation in accordance with 14.14.5 (vi).

OR

2. a positive £/kW tariff that increases annual average TNUoS charges to Generators to above the lower limit of the Limiting Regulation in accordance with 14.14.5 (vi).

Expressed in either case as:

$$AdjTariff = \frac{AdjRevenue}{ChargeableCapacity}$$

Where;

Cap_{EC} = Upper limit of the range specified in the Limiting Regulation
y = Error margin built in to adjust Cap_{EC}
GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for the **Financial Year**
ER = The latest OBR Forecast €/£ Exchange Rate published prior to the 31st October in the year preceding the relevant **Financial Year**
GCharge (Forecast) =The total forecast TNUoS revenue to be recovered from Generators in the **Financial Year** minus Charges for Physical Assets Required for Connection.
AdjRevenue = Adjustment Revenue
Chargeable Capacity = as per paragraph 14.18.6
AdjTariff = Any Adjustment Tariff required to remain compliant with the Limiting Regulation.

viii.) The currently applicable number of generation zones, determined in accordance with 14.15.37 and using the criteria outlined in paragraph 14.15.42, is detailed in **The Company's Statement of Use of System Charges** which is available from the **Charging website** and has been determined as 27.

ix.) The number of demand zones has been determined as 14, corresponding to the 14 GSP groups.

14.14.6 The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy.

The Transmission Licence requires The Company to operate the National Electricity Transmission System to specified standards. In addition The Company with other transmission licensees are required to plan and develop the National

Electricity Transmission System to meet these standards. These requirements mean that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to both the deterministic and supporting cost benefit analysis aspects of this standard. It is this obligation, which provides the underlying rationale for the ICRP approach, i.e. for any changes in generation and demand on the system, The Company must ensure that it satisfies the requirements of the Security Standard.

14.14.7 The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' output over the course of a year (capped at their Transmission Entry Capacity, TEC) can be accommodated in the most economic and efficient manner. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system both at the time of peak demand and across the remainder of the year. The Security Standard uses a Demand Security Criterion and an Economy Criterion to assess capacity requirements. The charging methodology therefore recognises both these elements in its rationale.

14.14.8 The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard, whilst the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.

14.14.9 The TNUoS charging methodology seeks to reflect these arrangements through the use of dual backgrounds in the Transport Model, namely a Peak Security background representative of the Demand Security Criterion and a Year Round background representative of the Economy Criterion.

14.14.10 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.14.11 In setting and reviewing these charges The Company has a number of further objectives. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
- be implementable within practical cost parameters and time-scales.

14.14.12 ~~Condition C13 of the Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, The Company is required to reduce TNUoS charges paid by eligible small generators by a designated sum, which will be determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery will ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year. For the avoidance of doubt, Condition C13 does not form part of the Use of System Charging Methodology~~. Not used

14.14.13 **The Company** will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a **Financial Year** by the end of the preceding January. However, **The Company** may update the tariffs part way through a **Financial Year**.

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14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery from demand only. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the local tariff represents the combination of the two local locational tariff components.

Finally, an Adjustment Tariff component may also be charged to Generators as per paragraph 14.14.5.

14.15.3 The process for calculating the TNUoS tariff is described below.

The Transport Model

Model Inputs

14.15.4 The DCLF ICRP 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, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given **Financial Year** "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

Generation Plant Type	Peak Security Background	Year Round Background
Intermittent	Fixed (0%)	Fixed (70%)
Nuclear & CCS	Variable	Fixed (85%)
Interconnectors	Fixed (0%)	Fixed (100%)
Hydro	Variable	Variable
Pumped Storage	Variable	Fixed (50%)
Peaking	Variable	Fixed (0%)
Other (Conventional)	Variable	Variable

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 The Company will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for **Financial Year** "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

Adjustments to Model Inputs associated with One-off Works

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a **Financial Year**, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

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Ref	Description of works	Adjustments
1	Undergrounding - A User requests to underground an overhead line at a greater cost.	As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL.
2	Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO.	As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model.
3	Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO.	As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model.
4	Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage.	As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage.

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

Ref	Description of works	Reasoning
1	Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried.	Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost.
2	Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route.	Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost.
3	Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs.	Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost.

4	Additional substation works - A User asks for screening to be provided around a new or existing substation.	The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model.
5	Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc.	The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model.
6	Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO.	The temporary circuit changes will not be incorporated into the transport model.
7	Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity.	No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged).
8	Early asset replacement - An asset is replaced prior to the end of its expected life.	As the asset is simply replaced, no data in the transport model is expected to change.
9	Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs.	The data in the transport model is unaffected.
10	Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18.	The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation.

11	Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18.	As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value.

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

Model Outputs

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total net GB demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. The currently applicable number of generation zones is detailed in **The Company's Statement of Use of System Charges** which is available from the **Charging website.**

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

Gi	=	Generation zone
j	=	Node
$NMkm_{PS}$	=	Peak Security Wider nodal marginal km from transport model
$WNMkm_{PS}$	=	Peak Security Weighted nodal marginal km
$ZMkm_{PS}$	=	Peak Security Zonal Marginal km
Gen	=	Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{j\,YR} = \frac{NMkm_{j\,YR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$	=	Year Round Wider nodal marginal km from transport model
$WNMkm_{YR}$	=	Year Round Weighted nodal marginal km
$ZMkm_{YR}$	=	Year Round Zonal Marginal km
Gen	=	Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows. If Nodal Demand from a node is less than 0 (Exporting) the nodal demand will be set to zero and therefore not contribute to the Zonal marginal km

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di	=	Demand zone
Dem	=	Positive Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 The number of generation zones will be fixed to 27 zones and the assignment of existing relevant nodes to these 27 generation zones will be fixed to those that are effective as of 31st March 2021 based on methodology in effect during the 2020/21. Relevant nodes are considered to be those with generation connected to them. **Financial Year**. Any newly created relevant nodes will be assigned to one of the 27 generation zones.

14.15.43 Not Used

14.15.44 Not Used

14.15.45 Not Used

Accounting for Sharing of Transmission by Generators

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

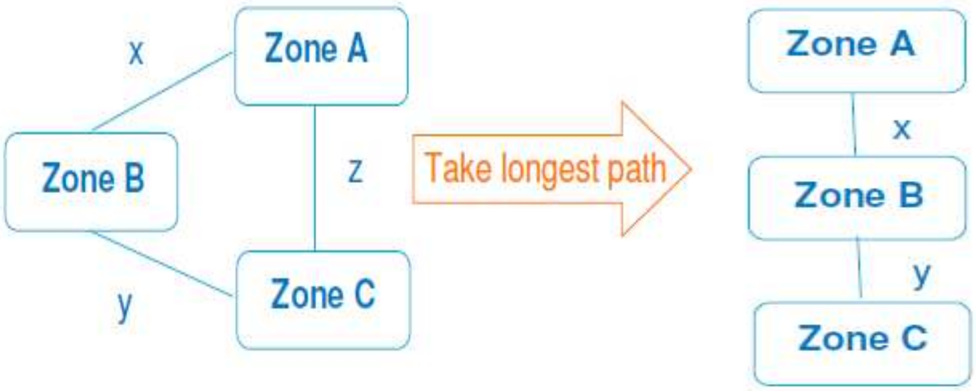
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by The Company in the Statement of Use of System Charges as new generation technologies are developed.

Carbon	Low Carbon
Coal	Wind
Gas	Hydro (excl. Pumped Storage)
Biomass	Nuclear
Oil	Marine
Pumped Storage	Tidal
Interconnectors	

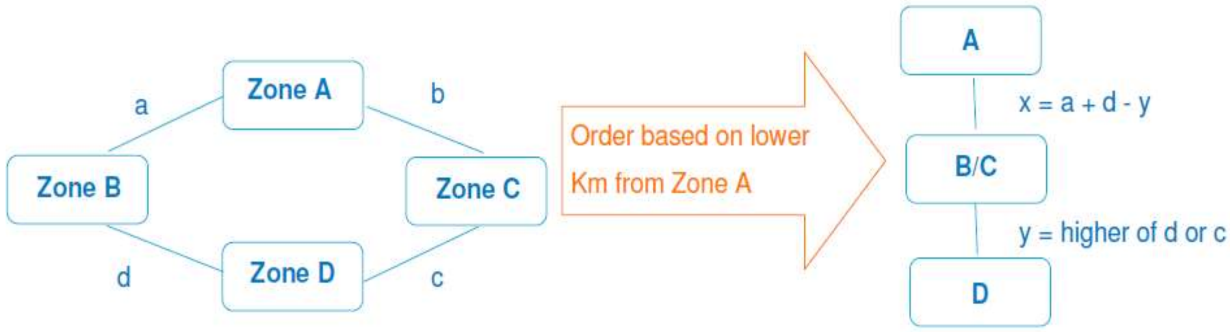
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

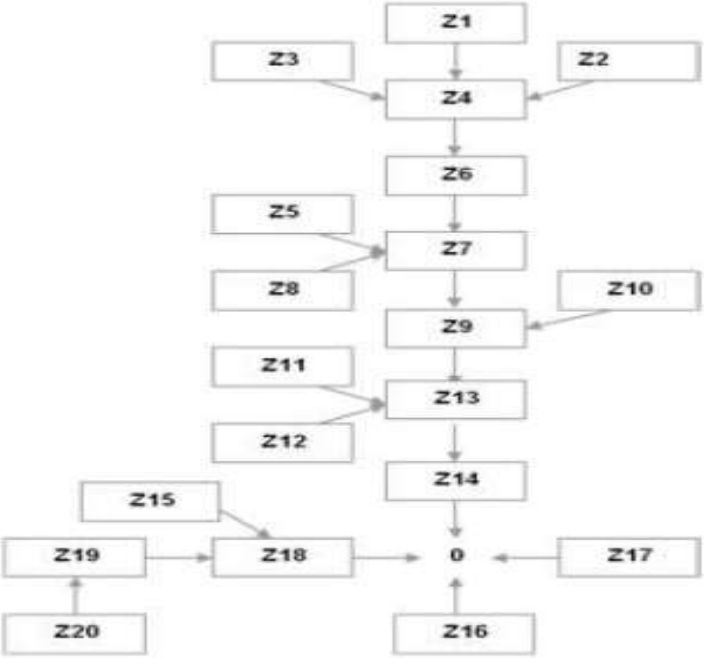
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.



- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.



14.15.51 An illustrative Connectivity diagram is shown below:



The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:

LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary

C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
BSF_{ab} = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

400kV OHL expansion constant calculation					
MW	**Type**	**£(000)/k**	**Circuit km***	**£/MWkm**	**Weight**
A	B	C	D	E = C/A	F=E*D
6500	La	700	500	107.69	53846
6500	Lb	780	0	120.00	0
3500	La/b	600	200	171.43	34286
3600	Lc	400	300	111.11	33333
4000	Lc/a	450	1100	112.50	123750
5000	Ld	500	300	100.00	30000
5400	Ld/a	550	100	101.85	10185
Sum			**2500 (G)**		**285400 (H)**
				Weighted Average (J= H/G):	**114.160 (J)**

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is NGET's regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions, applied in accordance with 14.15.64, provide a current annuity factor, as set out in **The Company's Statement of Use of System Charges** which is available from the **Charging website**.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The currently applicable overhead factor used in the calculation of the current expansion constant is, calculated as above, and detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website**. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, and the 2009/10 values for the annuity factor (6.6%) and overhead factor (1.8%), the final steps in establishing the expansion constant are demonstrated below:

400kV OHL expansion constant calculation	**Ave £/MWkm**
OHL	114.160
Annuitised	7.535
Overhead	2.055
Final	**9.589**

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.80.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, TOPI, (May–October average increase, as defined in the Transmission Licence) each subsequent year of the price control period. The current applicable expansion constant is detailed in **The Company's Statement of Use of System Charges** which is available from the **Charging website**.

14.15.69A Notwithstanding Paragraph 14.15.69 from the first year of (and during) the T2 price control (which starts on 1st April 2021), until a further change is made, the Expansion Constant will be that used in the 2020/21 **Financial Year** inflated in accordance with TOPI as per paragraph 14.15.69; and plus inflation as defined in the Transmission Licence for each subsequent year of the T2 price control.

Onshore Wider Circuit Expansion Factors

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of NGET and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Onshore Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 Calculation of HVDC circuit expansion factors, and AC sub-sea circuit expansion factors, shall include only: the cost of the converters (where applicable); and the cost of the cable; and a percentage of the total overhead project costs, defined as the combined costs of the cables and converters (as relevant) divided by the total capital cost of the project

14.15.77 The TO specific onshore circuit expansion factors which are currently applicable, are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website**.

Onshore Local Circuit Expansion Factors

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit. The 132kV onshore overhead line circuit expansion factors which are currently applicable, are detailed in **The Company's Statement of Use of System Charges** which is available from the **Charging website**.

Onshore Expansion Factors in RIIO-T2

14.15.79A Notwithstanding Paragraph 14.15.69, the previous paragraphs and following the same intent as adopted at Paragraph 14.15.69A, from the first year of (and during) the T2 price control (which starts on 1st April 2021), until a further change is made, the Onshore expansion factors (being the Onshore local circuit factors and the Onshore wider circuit expansion factors, except those used for HVDC circuits and sub-sea AC cable) will be the value used in the 2020/21 **Financial Year**. For clarity HVDC circuits and sub-sea AC cable will continue to be calculated in accordance with 14.15.75.

Offshore Circuit Expansion Factors

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the year that the offshore transmission assets are transferred to the Offshore Transmission Owner , the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

CRevOFTO1	=	The offshore circuit revenue in £ for Year 1
L	=	The total circuit length in km of the offshore circuit
CircRat	=	The continuous rating of the offshore circuit

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

AvCRevOFTO	=	The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control
L	=	The total circuit length in km of the offshore circuit
CircRat	=	The continuous rating of the offshore circuit

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in **The Company's Statement of Use of System Charges** which is available from the **Charging website**. These shall be recalculated for the start of each price control period using the formula in paragraph 14.15.82. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTORevInd_{t,f}}{TOPI_t}$$

where:

$OFTOInd_{t,f}$	=	the indexation factor for Offshore Transmission Owner *f* in respect of **Financial Year** *t*;
$OFTORevInd_{t,f}$	=	the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its transmission licence in respect of **Financial Year** *t*; and
$TOPI_t$	=	the indexation rate applied to the expansion constant in respect of **Financial Year** *t*.

Offshore Interlinks

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and

ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:

$\min\{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:

$\min\{ ILF_B \times TEC_B - RCap_B, \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:

$\min\{ Cap_{IBC}, ILF_C \times TEC_C - RCap_C, Cap_B - ILF_B \times TEC_B + \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) \}$

and

Cap_{IAB} = total capacity of the Offshore Interlink between substations A and B

Cap_{IBC} = total capacity of the Offshore Interlink between substations B and C

Cap_X = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

TEC_X = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

ILF_X = Offshore Interlink Load Factor, where X is A, B or C. The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent **Financial Years**.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given **Financial Year**.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future **Financial Years** unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

The Locational Onshore Security Factor

14.15.88 The locational onshore security factor for everything other than Identified Onshore Circuits is derived by running a secure DCLF ICRP transport study of the network excluding local circuits and Identified Onshore Circuits based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 For the purposes of 14.15.88 the secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[3].

3 https://www.nationalgrideso.com/industry-information/charging

14.15.90 For the purposes of 14.15.88 the locational onshore security factor, derived in accordance with paragraphs 14.15.88 and 14.15.89 and expressed to two decimal places, is based on an average from a number of studies conducted by The Company to account for future network developments. This security factor is reviewed for each price control period and fixed for the duration. The locational onshore security factor which is currently applicable, is detailed in The Company's **Statement of Use of System Charges**, which is available from the **Charging website.**

14.15.90A An Identified Onshore Circuit shall be defined as a single transmission HVDC subsea circuit or a single transmission AC subsea circuit between two MITS Nodes where there is only one route for the power to flow between the two MITS Nodes. The expansion factors for Identified Onshore Circuits are adjusted by dividing the applicable expansion factor for the Identified Onshore Circuits, calculated as per Sections 14.15.70 to 14.15.77, by the locational onshore security factor calculated in 14.15.90. When the locational onshore security factor is applied as per Section 14.15.96 and 14.15.97, this would result in an effective locational onshore security factor for Identified Onshore Circuits of 1.0.

Local Security Factors

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, derived in accordance with paragraphs 14.15.88 and 14.15.90.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; D_{min} = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

T_{cap} = transmission capacity built (MVA)

G_{cap} = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_{k} Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

14.15.94 The local offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived in accordance with 14.15.88-14.15.90.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than the locational onshore security factor, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{\mathrm{k}} \mathrm{Gen}_{\mathrm{k}}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.93 and 14.15.94

And other definitions as in 14.15.93.

Initial Transport Tariff

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$

$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$

$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

ITT_{GiPS} = Peak Security Initial Transport Tariff (£/MW) for each generation zone

ITT_{GiYRNS} = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

ITT_{GiYRS} = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ($ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

$ZMkm_{DiPS}$ = Peak Security Zonal Marginal km for each demand zone

$ZMkm_{DiYR}$ = Year Round Zonal Marginal km for each demand zone

ITT_{DiPS} = Peak Security Initial Transport Tariff (£/MW) for each demand one

ITT_{DiYR} = Year Round Initial Transport Tariff (£/MW) for each demand zone

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups.

a.

Where

$ITRR_G$	=	Initial Transport Revenue Recovery for generation
G_{Gi}	=	Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)
$ITRR_D$	=	Initial Transport Revenue Recovery for gross GSP group demand
D_{Di}	=	Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. When calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below). When calculating the initial revenue recovery for the Not Shared component of the Year Round background, the initial tariffs are multiplied by the **Year Round Not Shared Flag**.

Peak Security (PS) Flag

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

Generation Plant Type	PS flag
Intermittent	0
Other	1

Year Round Not Shared (YRNS) Flag

14.15.100 The revenue from a specific generator due to the Year Round Not Shared locational tariff needs to be multiplied by the appropriate Year Round Not Shared (YRNS) flag. The YRNS flag indicates the extent to which a generation plant type contributes to the need for transmission network investment at year round demand conditions in areas of the System where the proportion of Low Carbon generation exceeds Carbon generation as defined in 14.15.49.

Generation Plant Type	YRNS flag
Non Conventional Carbon	1
Conventional Carbon	ALF

Annual Load Factor (ALF)

14.15.101 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.102 For a given **Financial Year** "t" the Power Station ALF will be based on information from the previous five **Financial Years**, calculated for each **Financial Year** as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
TEC_p is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.103 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to The Company and relates to the total TEC of the Power Station.

14.15.104 Once all five **Financial Year** ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.105 In the event that only four **Financial Years** of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three **Financial Years** ALF would be used in the calculation of the final ALF. In the event that only three **Financial Years** of complete output (FPN or actual metered) data are available then these three **Financial Years** would be used.

14.15.106 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.107 In the event that there are not three full **Financial Years** of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three **Financial Years** of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.108 Users will receive draft ALFs before 25th December of the **Financial Year** (t-1) for the **Financial Year** (t) and will have a period of 15 **Business Days**

14.15.109 from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.110 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

Derivation of Generic ALFs

14.15.111 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five **Financial Years**' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

Fuel Type
Biomass
Coal
Gas
Hydro
Nuclear (by reactor type)
Oil & OCGTs
Pumped Storage
Onshore Wind
Offshore Wind
CHP

14.15.112 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.113 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.114 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

TNUoS Embedded Export Tariff

14.15.115 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.116 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

ITT_{DiPS} = Peak Security Initial Transport Tariff for the demand zone;
ITT_{DiYR} = Year Round Initial Transport Tariff for the demand zone, and
EX:
First **Financial Year** following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - AGIC) + AGIC$$

Second **Financial Year** following the implementation date of CMP 264/265:

$$= \frac{1}{3}(XP - AGIC) + AGIC$$

Third **Financial Year** following the implementation date of CMP 264/265 and every subsequent **Financial Year**:

= *AGIC*

Where
XP = Value of demand residual in **Financial Year** prior to implementation
AGIC = The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable **Financial Year** following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the TOPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the

supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of EET_{Di} will be floored at zero, so that EET_{Di} is always zero or positive.

Initial Revenue Recovery

14.15.117 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation

G_{Gi} = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

F_{PS} = Peak Security flag appropriate to that generator type

n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

$ITRR_{DPS}$ = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

D_{Di} = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.118 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for the Not-Shared component from Non Conventional Carbon. For Conventional Carbon the initial tariff for the Not Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery. The initial tariff for the Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}(ITT_{GiYRNSNCC} \times G_{Gi}) = ITRR_{GYRNSNCC}$$

$$\sum_{Gi=1}^{n}(ITT_{GiYRNSCC} \times G_{Gi} \times ALF) = ITRR_{GYRNSCC}$$

$$\sum_{Gi=1}^{n}(ITT_{Gi\,YRS} \times G_{Gi} \times ALF) = ITRR_{G\,YRS}$$

$$ITRR_{GYRNS} = ITRR_{GYRNSNCC} + ITRR_{GYRNSCC}$$

Where:

$ITRR_{GYRNSNCC}$	=	Year Round Not-Shared Initial Transport Revenue Recovery for Non Conventional Carbon generation
$ITRR_{GYRNSCC}$	=	Year Round Not-Shared Initial Transport Revenue Recovery for Conventional Carbon generation
$ITRR_{GYRNS}$	=	Year Round Not-Shared Initial Transport Revenue Recovery for generation
$ITRR_{GYRS}$	=	Year Round Shared Initial Transport Revenue Recovery for generation
ALF	=	Annual Load Factor appropriate to that generator.

14.15.119 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$	=	Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITRR_{EE}$	=	Initial Revenue impact for Embedded Exports
EEV_{Di}	=	Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for embedded exports can be positive or negative.

Deriving the Final Local Tariff (£/kW)

Local Circuit Tariff

14.15.121 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

$$\sum_{k} \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

k	=	Local circuit k for generator
$NLMkm_{Gj}{}^{L}$	=	Year Round Nodal marginal km along local circuit k using local circuit expansion factor.
EC	=	Expansion Constant
$LocalSF_k$	=	Local Security Factor for circuit k
CLT_{Gi}	=	Circuit Local Tariff (£/kW)

Onshore Local Substation Tariff

14.15.122 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.123 Using the above factors, the corresponding £/kW tariffs that are currently applicable, are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website**.

14.15.124 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by TOPI for each subsequent year of the price control period.

14.15.125 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where

ELT_{Gi}	=	Effective Local Tariff (£/kW)
SLT_{Gi}	=	Substation Local Tariff (£/kW)

14.15.126 Where tariffs do not change mid way through a **Financial Year**, final local tariffs will be the same as the effective tariffs:

ELT_{Gi} = LT_{Gi}

Where

LT_{Gi} = Final Local Tariff (£/kW)

14.15.127 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$LT_{Gi} = \frac{12 \times \left(ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left(ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:

b = number of months the revised tariff is applicable for

FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.128 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR_G} = \sum_{j=Gi} \mathrm{LT_{Gi}} * G_j$$

Where

$\mathrm{LCRR_G}$	=	Local Charge Revenue Recovery
G_j	=	Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

Offshore substation local tariff

14.15.129 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.130 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.131 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.132 A discount shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. The currently applicable discount is detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website**. This will be inflated by TOPI each year and reviewed every price control period.

14.15.133 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.134 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore\\ substations}} \left(SLT_k \times \sum_k Gen_k \right)$$

Where:

SLT_k	=	the offshore substation tariff for substation k
Gen_k	=	the generation connected to offshore substation k

The Residual Tariff

14.15.135 The total revenue to be recovered through TNUoS charges is determined each year with reference to the ~~T~~transmission ~~L~~licensees' ~~P~~price ~~C~~control formulas~~ less the costs expected to be recovered through Pre-Vesting connection charges~~. The~~Hence in any given year t, a~~ target forecast revenue figure for TNUoS charges ~~(TRR$_t$)~~ is set ~~after adjusting for any under or over recovery for and including, the small generators discount is~~ as ~~follows~~per paragraph 14.14.2~~:~~. For the purpose of calculating demand tariffs only, forecast inputs for revenue and the demand charging base will be determined 15 months before the **Financial Year** and subsequently reconciled and recovered through succeeding **Financial Years** once revenue requirements are known.

$$\cancel{TRR_t = R_t - PVC_t - SG_{t-1}}$$

~~Where~~

~~TRR_t~~	~~=~~	~~TNUoS Revenue Recovery target for year t~~
~~R_t~~	~~=~~	~~Forecast Revenue allowed under The Company's Price Control for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.~~
~~PVC_t~~	~~=~~	~~Forecast Revenue from Pre-Vesting connection charges for year t~~
~~SG_{t-1}~~	~~=~~	~~The proportion of the under/over recovery included within R_t which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.~~

14.15.136 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.137 As a result of the factors above, in order to ensure adequate recovery of total Transmission Owner revenue, a constant non-locational

Residual Tariff for demand is calculated, which includes infrastructure substation asset costs. This tariff is added to the initial transport tariffs for demand only so that the total revenue recovery is achieved.

$$\frac{TRR - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE} - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_{GG} - AdjRevenue}{\sum_{Di=1}^{14} D_{Di}}$$

Where

RT	=	Residual Tariff (£/MW)
p	=	Proportion of revenue to be recovered from demand
AdjRevenue	=	Adjustment Revenue as per paragraph 14.14.5

Final £/kW Tariff

14.15.138 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds and the non-locational residual tariff (for demand) or Adjustment Tariff and local tariff (for generation):

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + IFF_{GiYRS} + AdjTariff_i}{1000} + LT_{Gi}$$

and

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT}{1000}$$

Where

ET_{Gi}= Effective Generation TNUoS Tariff expressed in £/kW (ET_{Gi} would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances ITT_{GiPS}, ITT_{GiYRNS} and ITT_{GiYRS} will be applied using Power Station specific data)

$AdjTariff_i$ = AdjTariff (from 14.14.5) applicable in time period ‘i’.

ET_{Di}= Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where
ET_{EEi}= Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges ET_{Gi} will be published as ITT_{GiPS}; ITT_{GiYRNS}, ITT_{GiYRS}, RT_G and LT_{Gi} and $AdjTariff_i$ (if required)

14.15.139 Where tariffs do not change mid way through a **Financial Year**, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEi}$$

14.15.140 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left(ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{Di} = \frac{12 \times \left(ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$ and $$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The ET_{Gi} element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station G_{Gi}, aggregated to ensure overall correct revenue recovery.

14.15.141 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then i = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

RFT_{Di} = Revised Final Tariff (£/kW)

14.15.142 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.143 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the **Financial Year** in question of which Grid Supply Points fall into which TNUoS zones.

14.15.144 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.145 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

14.15.146 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

14.15.147 The factors which will affect the level of TNUoS charges from year to year include-;

- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the Year Round Not Shared (YRNS) Flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports
- the £/€ exchange rate and expected Generator Output

14.15.148 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

Stability & Predictability of TNUoS tariffs

14.15.149 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

£/kW Tariff = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

$NHHD_F$ = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

FL_G = Forecast Liability incurred for the GSP Group concerned.

$NHHC_G$ = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff (ET_{Gi}) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single **Financial Year**, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole **Financial Year**, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

FT	=	Final annual TNUoS Tariff expressed in £/kW
Gi	=	Generation zone
STTEC Period	=	A period applied for in days as defined in the CUSC

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given **Financial Year** (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single **Financial Year**, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole **Financial Year**, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

<u>Initial 17 weeks (high rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

<u>Remaining weeks (low rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
G_i is the generation TNUoS zone; and
P is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

Annex 9 – CMP286/CMP287 Original Legal Text

CMP286/287 changes shown in red text – 14.14.2, 14.15.135 and 14.29

CMP286/287 changes that could be done alternatively via Housekeeping Modification shown in blue text – 14.14.1, 14.14.12, 14.14.13, 14.15.135, 14.17.16 and 14.17.29.11

14.17 Demand Charges

Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

Basis of Gross Demand Charges

14.17.3 Gross Demand charges are based on a de minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a **Financial Year**, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

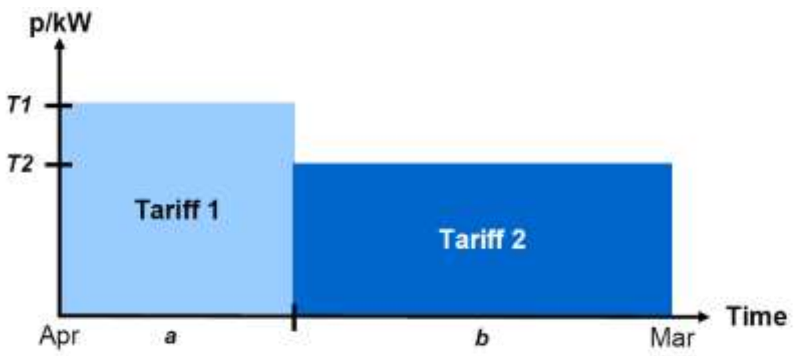
14.17.6 If there is a single set of energy tariffs within a **Financial Year**, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges.

14.17.7 If multiple sets of gross demand tariffs are applicable within a single **Financial Year**, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Dema} \qquad \times \left(\frac{(a \times Tariff\ 1)+(b \times Tariff\ 2)}{12}\right)$$

where:

Tariff 1	=	Original tariff,
Tariff 2	=	Revised tariff,
a	=	Number of months over which the original tariff is applicable,
b	=	Number of months over which the revised tariff is applicable.



14.17.8 If multiple sets of energy tariffs are applicable within a single **Financial Year**, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

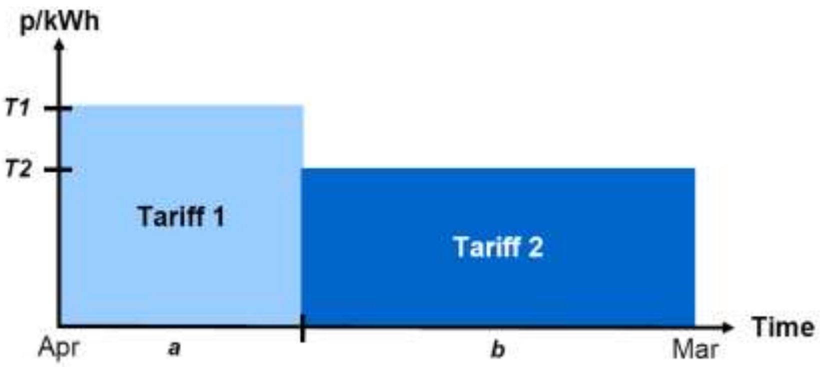
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.



Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a **Financial Year**, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single **Financial Year,** embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Deman} \quad \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

where:

Tariff 1	=	Original tariff,
Tariff 2	=	Revised tariff,
a	=	Number of months over which the original tariff is applicable,
b	=	Number of months over which the revised tariff is applicable.

Supplier BM Unit

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff), *and*
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the **Financial Year** (and the p/kWh tariff).

Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement

14.17.14 The Chargeable Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the net import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

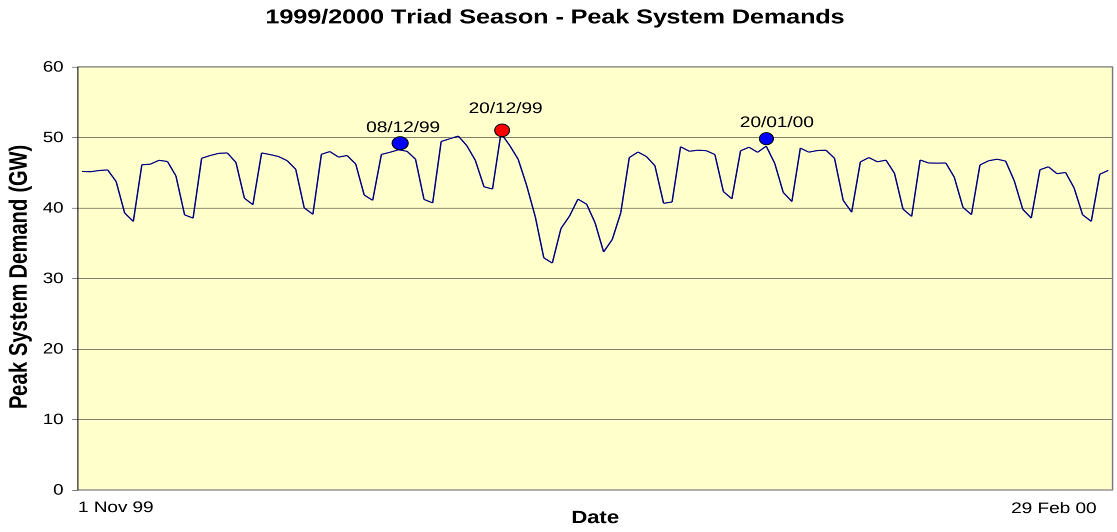
- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.
- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

Small Generators Tariffs

~~14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.~~ Not used

The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a **Financial Year**, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the **Financial Year** inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak netdemand. An illustration is shown below.



Half-hourly metered demand charges

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

Monthly Charges

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the **Financial Year** for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the **Financial Year** for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next **Financial Year**. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable demand forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding **Financial Year** will be used where User settlement data is available and where The Company calculates its forecast before the **Financial Year**. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the **Financial Year** to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding **Financial Year** to derive a forecast of the User's HH gross demand and embedded export at Triad for this **Financial Year**.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the **Financial Year** to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding **Financial Year** to derive a forecast of the User's NHH energy consumption for this **Financial Year**.

For new Users who have completed a Use of System Supply Confirmation Notice in the current **Financial Year**:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this **Financial Year**.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that **Financial Year** and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this **Financial Year**.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

Reconciliation of Demand Charges and TNUoS Charges in the event of exceeding the limits to Generator charges in the Limiting Regulation

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

14.17.24 In the event of annual average transmission charges incurred by Generator Users in the **Financial Year** not being in compliance with the upper or lower limits in the Limiting Regulation an Ex-Post Reconciliation adjustment will be applied to Generator and Demand Users to bring charges back into compliance.

Initial Reconciliation of demand charges

14.17.25 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

Initial Reconciliation Part 1– Half-hourly metered demand

14.17.26 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

14.17.27 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months concerned for each zone for that **Financial Year**. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.28 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that **Financial Year**. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

Initial Reconciliation Part 2 – Non-half-hourly metered demand

14.17.29 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

Final Reconciliation of demand charges

14.17.30 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.31 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

Reconciliation of manifest errors

14.17.32 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.34 33 will be in accordance with Sections 14.17.254 to 14.17.3130. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.33 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.34 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or
b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.35 A manifest error shall only be reconciled if it has been identified within the **Financial Year** for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

Ex-post Reconciliation of Generator and Demand Charges in the event of exceeding the limits to Generator charges in the Limiting Regulation

14.17.36 The Company shall, following the completion of each **Financial Year**, produce a statement setting out the annual average transmission charges paid in aggregate by Generators in €/MWh as per paragraph 14.14.5.

14.17.37 In the event that the annual average transmission charges attributable to Generators exceeds the upper limit established in the Limiting Regulation then an Ex-post Reconciliation will be calculated for Generator and Demand Users as per the below and will be invoiced at the time of generation reconciliation and initial demand reconciliation.

i) The Ex-post Reconciliation amount for Demand Users will be calculated as:

Dadj = GCharge (Actual)-($GO_A * (CapEC * ER_A)$)

Where:
Dadj = Revenue to be recovered from Demand
GO_A = Actual generator output in the previous **Financial Year**

CapEC = The upper limit of the Limiting Regulation
ER_A = Actual exchange rate in the previous **Financial Year**
GCharge (Actual) = Actual charges to Generators in the previous **Financial Year**

ii) The rate applied to HH gross Demand, in order to adjust for any TNUoS recovery from generation outside of the range of the Limiting Regulation

$$DRadj = \left(\frac{\text{Dadj}}{GTD}\right)$$

Where
DRadj = Rate applied to AHHD in £/kW
GTD = Total actual system metered Gross Triad Demand (kW)

iii) The rate applied to NHH energy consumption, in order to adjust for compliance with the Limiting Regulation in the **Financial Year** is calculated by:

$$ERadj \quad = \left(\frac{Dadj-(AHHD \times DRadj)}{ANHHC}\right) \text{x } 100$$

Where
AHHD = The actual gross half-hourly metered Triad Demand (kW) for half-hourly demand
ERadj = Rate applied to energy consumption for the demand recovery in p/kWh

ANHHC = Total actual annual non-half-hourly metered energy consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) for each day of the preceding **Financial Year**,

iv) <u>The Ex-Post Reconciliation amount for Generator Users will be calculated as:</u>

$$\text{Gadj} = Dadj * -1$$

Where:
Dadj = Revenue to be recovered from Demand Users
Gadj = Revenue to be paid to Generator Users

v) The rate applied to Generator Chargeable Capacity in the preceding **Financial Year**, in order to adjust for any recovery of TNUoS from generation outside of the range of the Limiting Regulation, is:

$$\text{GRadj} = \frac{Gadj}{ChargeableCapacity}$$

Where:

GRadj = Adjustment rate to be applied to Generators
Chargeable Capacity = As per paragraph 14.18.6

14.17.38 In the event that the annual average transmission charges attributable to Generators is below the lower limit established in the Limiting Regulation then an Ex-post Reconciliation will be calculated for Generator and Demand Users as per the below and will be invoiced at the time of generation reconciliation and initial demand reconciliation.

i) Ex-post reconciliation for Demand Users:

Dadj = GCharge (Actual)-0

Where:

Dadj = Revenue to be credited to Demand
GCharge (Actual) = Actual charges to Generators in the previous **Financial Year**

ii) The rate applied to HH gross Demand, in order to adjust for any recovery of TNUoS from generation outside of the range of the Limiting Regulation

$$DRadj \quad = \left(\frac{Dadj}{GTD}\right)$$

Where
DRadj = Rate applied to AHHD in £/kW
GTD = Total actual system metered gross triad demand (kW)

iii) The rate applied to NHH energy consumption, in order to adjust for compliance with the Limiting Regulation in the **Financial Year** is calculated by:

$$ERadj \quad = \left(\frac{Dadj - (AHHD \quad \times DRadj)}{ANHHC}\right) \text{x } 100$$

Where
AHHD = The actual gross half-hourly metered Triad Demand (kW) for half-hourly demand
ERadj = Rate applied to energy consumption for the demand recovery in p/kWh
ANHHC = Total actual annual non-half-hourly metered energy consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) for each day of the preceding **Financial Year**

Ex-post reconciliation for Generator Users:

The recovery from Generator Users will be

Gadj = $Dadj * -1$

Where:

Dadj = Revenue to be dispersed to Demand
Gadj = Revenue to be recovered from Generator Users

iv) The rate applied to Generator Chargeable Capacity in the preceding **Financial Year**, in order to adjust for any recovery of TNUoS from generation outside of the range of the Limiting Regulation, is:

$$GRadj = \frac{Gadj}{ChargeableCapacity}$$

Where:

GRadj = Adjustment rate to be applied to Generators
Chargeable Capacity = As per paragraph 14.18.6

Implementation of P272

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding **Financial Years** up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a **Financial Year** would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each **Financial Year** which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year **Financial Year** as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full **Financial Year** unless 14.17.35.3 applies

14.17.35.3 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position

14.17.35.4 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.5 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/ Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the **Financial Years** up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each **Financial Year** up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following **Financial Year** up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the **Financial Year** 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a **Financial Year** TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.6 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

HH Elective Metering from 1st April 2017. The following section describes how meters migrating to, or already within, Measurement Classes E,F and G will be charged in terms of TNUoS after 31st March 2017.

14.17.29.8 A change from NHH to HH within a **Financial Year** would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation for Non-Half Hourly (NHH) meters migrating to Measurement Classes E, F & G for the **Financial Year** which begins after 31 March 2017.

14.17.29.9 Notwithstanding 14.17.9, for each **Financial Year** which begins after 31 March 2017 demand associated with Measurement Classes F and G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full **Financial Year** up until the **Financial Year** which begins after 31st March 2023. Demand associated with Measurement Class E will continue to be treated as Chargeable Demand Capacity (HH).

14.17.29.10 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from ELEXON i.e. Suppliers need not Supply any additional information.

14.17.29.11 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in ~~14.17.16 and~~ 14.17.17 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect the basis on which demand will be charged for TNUoS i.e. volumes associated with those Metering Systems that have transferred to Measurement Class F & G in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity.

Further Information

14.17.38 14**.**25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded consumption and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.39 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current **Financial Year**.

14.17.40 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

14.29 Stability & Predictability of TNUoS tariffs

Stability of tariffs

The Transmission Network Use of System Charging Methodology has a number of elements to enhance the stability of the tariffs, which is an important aspect of facilitating competition in the generation and supply of electricity. This appendix seeks to highlight those elements.

For the purpose of calculating demand tariffs only, forecast inputs for revenue and the demand charging base will be determined 15 months before the Financial Year as per 14.14.2. Fixing of revenue and demand inputs provides additional stability and predictability to Demand Users.

Each node of the transmission network is assigned to a zone, these zones are themselves fixed. The result of this is to dampen fluctuations that would otherwise be observed at a given node caused by changes in generation, demand, and network parameters. The criteria used to establish generation zones are part of the methodology and are described in Paragraph 14.15.42.

In addition to fixing zones, other key parameters within the methodology are also fixed for the duration of the price control period or annual changes restricted in some way. Specifically:

- the expansion constant, which reflects the annuitised value of capital investment required to transport 1MW over 1km by a 400kV over-head line, changes annually according to TOPI. The other elements used to derive the expansion constant are only reviewed at the beginning of a price control period to ensure that it remains cost-reflective. This review will consider those components outlined in Paragraph 14.15.59 to Paragraph 14.15.69.

- the expansion factors, which are set on the same basis of the expansion constant and used to reflect the relative investment costs in each TO region of circuits at different transmission voltages and types, are fixed for the duration price control. These factors are reviewed at the beginning of a price control period and will take account of the same factors considered in the review of the expansion constant.

- the locational security factor, which reflects the transmission security provided under the NETS Security and Quality of Supply Standard, is fixed for the duration of the price control period and reviewed at the beginning of a price control period.

Predictability of tariffs

The Company revises TNUoS tariffs each year to ensure that these remain cost-reflective and take into account changes to allowable income under the price control and TOPI. There are a number of provisions within the Transmission Licence and the CUSC designed to promote the predictability of annually varying charges. Specifically, The Company is required to give the Authority 150 days notice of its intention to change use of system charges together with a reasonable assessment of the proposals on those charges; and to give Users 2 months written notice of any revised charges. The Company typically provides an additional months notice of revised charges through the publication of "indicative" tariffs. Shorter notice periods are permitted by the framework but only following consent from the Authority.

These features require formal proposals to change the Transmission Use of System Charging Methodology to be initiated in October to provide sufficient time for a formal consultation and the Authority's veto period before charges are indicated to Users.

More fundamentally, The Company also provides Users with the tool used by The Company to calculate tariffs. This allows Users to make their own predictions on how future changes in the generation and supply sectors will influence tariffs. Along with the price control information, the data from the Seven Year Statement, and Users own prediction of market activity, Users are able to make a reasonable estimate of future tariffs and perform sensitivity analysis.

To supplement this, The Company also prepares an annual information paper that provides an indication of the future path of the locational element of tariffs over the next five years.[4] This analysis is based on data included within the Seven Year Statement. This report typically includes:

- an explanation of the events that have caused tariffs to change;
- sensitivity analysis to indicate how generation and demand tariffs would change as a result of changes in generation and demand at certain points on the network that are not included within the SYS;
- an assessment of the compliance with the zoning criteria throughout the five year period to indicate how generation zones might need to change in the future, with a view to minimising such changes and giving as much notice of the need, or potential need, to change generation zones; and
- a complete dataset for the DCLF Transport Model developed for each future year, to allow Users to undertake their own sensitivity analysis for specific scenarios that they may wish to model.

The first year of tariffs forecasted in the annual information paper are updated twice throughout the proceeding **Financial Year** as the various Transport and Tariff model inputs are received or amended. These updates are in addition to the Authority 150 days notice and publication of "indicative" tariffs.

The parameters used in the calculation of generation cap (in paragraph 14.15.5 v.)) will be published along with the forecast and confirmed values in the Tariff Information Paper which is produced in compliance with Condition 5 (of the NGC's proposed GB electricity transmission use of system charging methodology - the Authority's decisions document March 2005 80/5).

In addition, The Company will, when revising generation charging zones prior to a new price control period, undertake a zoning consultation that uses data from the latest information paper. The purpose of this consultation will be to ensure tariff zones are robust to contracted changes in generation and supply, which could be expected to reduce the need for re-zoning exercises within a price control period.

[4] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/