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 charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) 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 connection sites and to provide transmission system security.

14.14.2 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding 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).

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 Generation 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 meeting the Target Rate for Recovery from Generators 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 or to prevent annual average TNUoS charges payable by Generator Users exceeding the Target Rate for Recovery from Generators then an Adjustment Tariff will be applied to all Generation Users.

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 the Target Rate for Recovery from Generators of €1.25/MWh

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:

$$AdjRevenue = (GO * (TRR * ER)) - GCharge(Forecast)$$

iii.) Where annual average 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:

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

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

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

v.) The error margin used to maintain compliance with the Limiting Regulation for the charging year is expressed as:

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

vi.) 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).

vii.) The Company will use the latest OBR Forecast of £/€ exchange rate published prior to the 31st October in the year preceding the relevant Charging Year to convert average annual transmission charges payable by Generators to a comparable value for the purposes of assessing compliance with the Targeted Rate.

viii.) In addition, The Company will include Additional Adjustment Revenue (AddAdjRev) if it determines that the revenues recovered from Generators (AdjGenRev) plus revenues recovered from Generators through BSUoS charges that do not form part of the Ancillary Services Exclusion (ExcessBSUoSRev) will result in annual average charges to Generators outside the target range in the Limiting Regulation.

ix.) The Additional Adjustment Revenue will be expressed as:

$$AddAdjRev = (GO * \Big(\big(CapEC * (1 - y)\big) * ER\Big) - (AdjGenRev + ExcessBSUoSRev)$$

x.) The Adjustment Tariff will be either:

1. a negative £/kW tariff that reduces annual average TNUoS charges to Generators to achieve the Target Rate for Recovery from Generators.

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 as:

$$AdjTariff = \left(\frac{AdjRevenue + AddAdjRev}{ChargeableCapacity}\right)$$

Where;

TRR =

Targeted Rate for Recovery value to be collected from Generators expressed in €/ MWh

GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for the Charging Year

ER = The latest OBR Forecast €/£ Exchange Rate published prior to the 31st October in the year preceding the relevant Charging Year

GCharge (forecast) =The total forecast revenue to be recovered from Generators in the Charging Year minus Charges for Physical Assets Required for Connection.

AdjRevenue = Revenue Adjustment for the Target Rate of Recovery from Generators or Limiting Regulation as applicable

Chargeable Capacity = as per paragraph 14.18.6

AdjTariff = Any Adjustment Tariff required to meet the Target Rate for Recovery from Generators or to remain compliant with the Limiting Regulation

~~iv.) The application of a Transmission Network Use of System Revenue split between generation and demand where the proportion of the total revenue paid by generation, for the purposes of tariff setting for a charging year n, is x times the total revenue, where x is:~~

~~1. Whilst European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit on annual average transmission charge payable by generation) is in effect (a “Limiting Regulation”) then:~~

$$x_n = \frac{(Cap_{EC} * (1 - y)) * GO}{MAR * ER}$$

~~Where;~~

~~Cap_{EC} = Upper limit of the range specified a Limiting Regulation~~

~~y = Error margin built in to adjust Cap_{EC} to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n~~

~~GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n~~

~~MAR = Forecast TO Maximum Allowed Revenue (£) for charging year n~~

~~ER = OBR Spring Forecast €/£ Exchange Rate in charging year n-1~~

2. ~~Where there is no Limiting Regulation, then x for charging year n is set as the value of x used in the last charging year for which there was a Limiting Regulation.~~

~~v.)~~viii.) The number of generation zones using the criteria outlined in paragraph 14.15.42 has been determined as 21.

~~vi.)~~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.

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.

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 residual element;~~ 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 Residual Tariff

14.15.134 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target 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:

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

Where

TRR_t = TNUoS Revenue Recovery target for year t

R_t	=	Forecast Revenue allowed under The Company's RPI-X Price Control Formula 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.

14.15.135 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.

14.15.96 As a result of the factors above, in order to ensure adequate recovery of total Transmission Owner revenue ~~recovery~~, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. This tariff is added to the initial transport tariffs for demand only so that ~~It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and~~ the total revenue recovery is achieved.

14.15.136

$$\cancel{RT_D = \frac{(p\times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}}$$

$$RT_G = \frac{\left[(1-p)\times TRR\right] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

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

Where

RT	=	Residual Tariff (£/MW)
AdjRevenue	=	Adjustment Revenue as per paragraph 14.14.5
AddAdjRevenue	=	Additional Adjustment Revenue as per paragraph 14.14.5

Final £/kW Tariff

14.15.137 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 ~~and the~~ local tariff (for generation):

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

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

and

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

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 (as per paragraph 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)

14.15.138 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

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

14.15.139 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.

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

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)

14.15.141 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**.**

14.15.142 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 charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.143 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.

14.15.144 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.

14.15.145 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**.

14.15.146 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

14.15.147 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

14.15.148 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 charging 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 charging 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 charging 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.**

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 charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

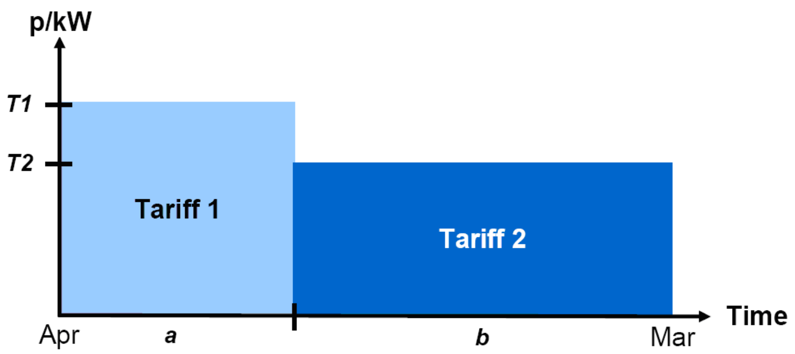
14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges.

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging 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,

$$Annual\ Liability_{Dema} \quad Chargeable\ Gross\ Demand\ Capacity \times \left(\frac{(a\times Tariff\ 1)+(b\times Tariff\ 2)}{12}\right)$$

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 charging 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.

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

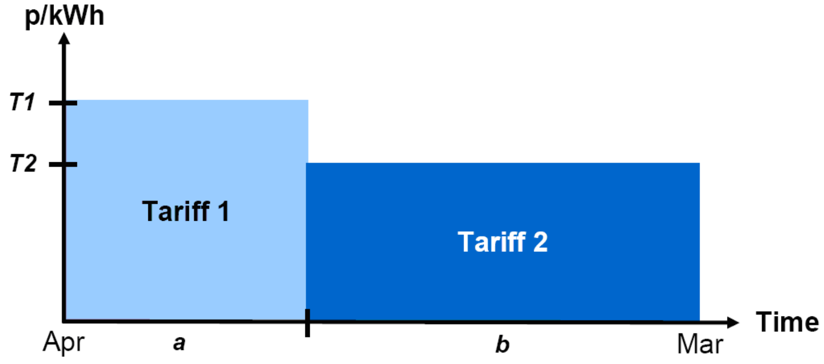
Where:

$T1_S$ = 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 charging 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 charging 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,

$$Annual\ Liability_{Deman} \quad \begin{matrix} Chargeable\ Embedded \\ Export\ Capacity \end{matrix} \quad \times \left(\frac{(a \times Tariff\ 1)+(b \times Tariff\ 2)}{12}\right)$$

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:

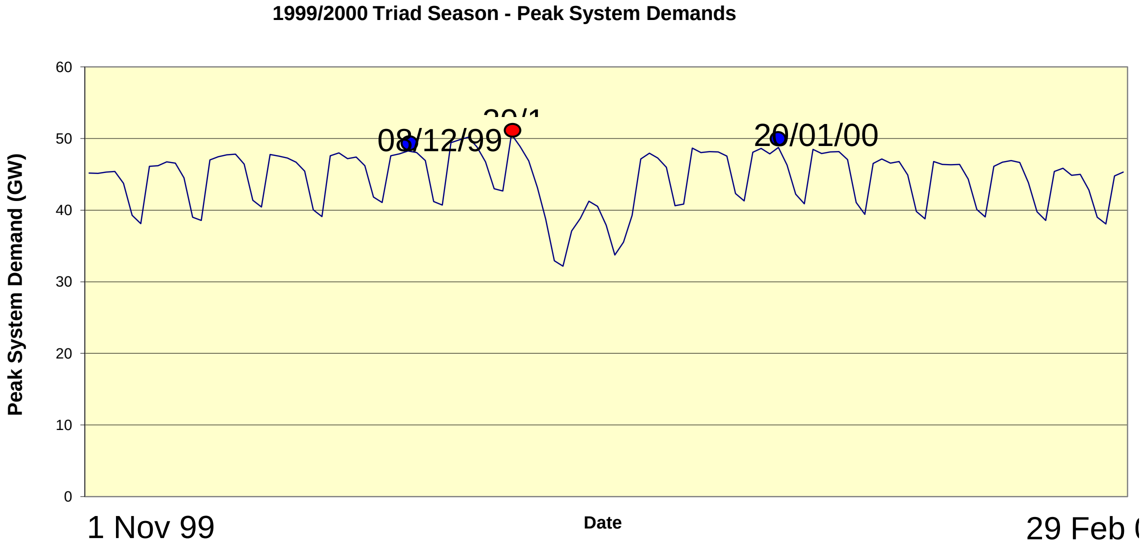
- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during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

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 Charging 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 User's to bring charges back into compliance.

Initial Reconciliation of demand charges

~~14.17.23~~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

~~14.17.24~~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.

~~14.17.25~~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.

~~14.17.26~~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

~~14.17.27~~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

~~14.17.28~~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).

~~14.17.29~~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

~~14.17.30~~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~~14.17.33~~33 will be in accordance with Sections 14.17.25~~14.17.24~~4 to 14.17.31~~14.17.30~~30. 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.

~~14.17.31~~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.

~~14.17.32~~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.

~~14.17.33~~14.17.35 A manifest error shall only be reconciled if it has been identified within the charging 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 Charging Year, produce a statement setting out the annual average charge 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 Generation and Demand Users as per the below and will be invoiced at the time of Generation and Demand Reconciliation.

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

$$\text{Dadj} = \text{GCharge (Actual)} - (GO_A * (CapEC * ER_A))$$

Where:
Dadj = Revenue to be recovered from Demand
GO_A = Actual generator output in the previous Charging Year
CapEC = The upper limit of the Limiting Regulation
ER_A = Actual exchange rate in the previous Charging Year
GCharge (Actual) = Actual charges to Generators in the previous Charging Year

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

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

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 Charging Year is calculated by:

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

Where
AHHD = The actual gross half-hourly metered Triad Demand (kW) for HH 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 Charging Year,

iv) The Ex-Post Reconciliation amount for Generation Users will be calculated as:

Gadj = $Dadj * -1$

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

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

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

Where:

GRadj = Adjustment rate to be applied to generators
ChargeableCapacity = As per paragraph 14.18.6

14.17.3~~78~~ 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 charging year

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

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

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 Charging Year is calculated by:

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

Where
AHHD = The actual gross half-hourly metered Triad Demand (kW) for HH 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 Charging Year

Ex-post reconciliation for Generation Users:

The recovery from Generator Users will be

Gadj = $Dadj * -1$

Where:
Dadj = Revenue to be credited to Demand
Gadj = Revenue to be recovered from Generation

iv) The rate applied to Generator Chargeable Capacity in the preceding Charging Year, in order to adjust for any recovery of TNUoS 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

14.18 Generation charges

Parties Liable for Generation Charges

14.18.1 The following CUSC parties shall be liable for generation charges:

i) Parties of Generators that have a Bilateral Connection Agreement with The Company.

ii) Parties of Licensable Generation that have a Bilateral Embedded Generation Agreement with The Company.

14.18.2 14.26 Classification of parties for charging purposes provides an illustration of how a party is classified in the context of Use of System charging and refers to the relevant paragraphs most pertinent to each party.

Structure of Generation Charges

14.18.3 Generation Tariffs are comprised of Wider and Local Tariffs. The Wider Tariff is comprised of (i) a Peak Security element, (ii) a Year Round Not-Shared element, (iii) Year Round Shared element and (iv) an Adjustment Tariff (if required).~~a residual element~~. The Peak Security element of the Wider Tariff is not applicable for intermittent generators as the PS flag is set to zero. The Year Round Not Shared element is multiplied by the YRNS Flag, which for Non-Conventional Carbon Generators results in no change to the tariff, whereas for Conventional Carbon generators the tariff is reduced by ALF

14.18.4 The Local Tariff contains a substation element and may also contain a circuit element. Specifically, all transmission connected generation will be liable to pay a local substation charge, with some of these also being liable to pay a local circuit charge. For the avoidance of doubt, embedded generation has a zero local tariff.

14.18.5 The intention of the charging rules is to charge the same physical entity only once.

14.18.6 The basis of the generation charge for Power Stations is the Chargeable Capacity and the short-term chargeable capacity (as defined below for positive and negative charging zones).

14.18.7 If there is a single set of Wider and Local generation tariffs within a charging year, the Chargeable Capacity is multiplied by the relevant generation tariff to calculate the annual liability of a generator.

$$Local\ Annual\ Liability = Chargeable\ Capacity \times Local\ Tariff$$

The Wider Tariff is broken down into ~~four~~ components as described in 14.18.3. The breakdown of the Wider Charge for Conventional and Intermittent Power Stations are given below:

Conventional Low Carbon-

$$Wider\ Annual\ Liability = Chargeable\ Capcity \times (PS\ Tariff + YRNS\ Tariff) + (YRS\ Tariff \times ALF) + AdjTariff$$

$$Wider\ Annual\ Liability = Chargeable\ Capacity \times (PS\ Tariff + YRNS\ Tariff$$

$$+ (YRS\ Tariff \times ALF) + ResidualTariff)$$

Conventional Carbon

$$Wider\ Annual\ Liability = Chargeable\ Capacity \times (PS\ Tariff + (YRNS\ Tariff \times ALF) + (YRS\ Tariff \times ALF) + AdjTariff)$$

$$\cancel{Wider\ Annual\ Liabiity\ Chargeable\ Capacity\ x\ (PS\ Tariff + (YRNS\ Tariff \times ALF) + (YRS\ Tariff \times ALF) + Residual\ Tariff)}$$

Intermittent -

$$Wider\ Annual\ Liabiity = Chargeable\ Capacity \times (YRNS\ Tariff + (YRS\ Tariff \times ALF) + AdjTariff)$$

$$Wider\ Annual\ Liability = Chargeable\ Capacity \times (YRNS\ Tariff + (YRS\ Tariff \times ALF) + ResidualTariff)$$

Where:
PS Tariff = Wider Peak Security Tariff
YRNS Tariff = Wider Year Round Not-Shared Tariff
YRS Tariff = Wider Year Round Shared Tariff
Adj Tariff = Adjustment Tariff

14.18.8 If multiple sets of Wider and Local generation tariffs are applicable within a single charging year, the Chargeable Capacity is multiplied by the relevant tariffs pro rated over the entire charging year, across the months that they are applicable for.

$$Annual\ Liability = Chargeable\ Capacity \times \left(\frac{a \times Tariff\ 1 + b \times Tariff\ 2}{12} \right)$$

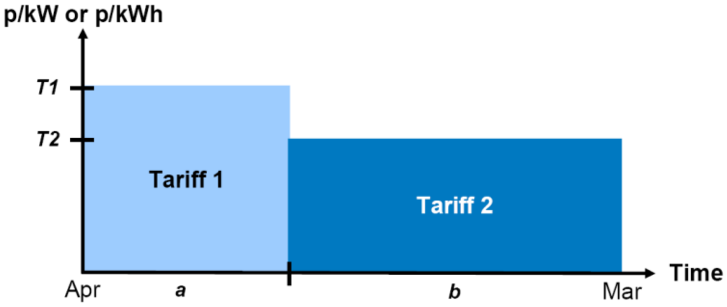
where:

Liability 1 = Original annual liability,

Liability 2 = Revised annual liability,

a = Number of months over which the original liability is applicable,

b = Number of months over which the revised liability is applicable.



14.18.9 For the avoidance of doubt if there are multiple sets of Wider and Local generation tariffs applicable within a single charging year and a tariff changes from being positive to negative or vice versa, the Chargeable Capacity for the entire charging year will be determined based on the net position of the pro rated tariffs for each affected generator.

Basis of Wider Generation Charges

Generation with positive wider tariffs

14.18.10 The Chargeable Capacity for Power Stations with positive wider generation tariffs is the highest Transmission Entry Capacity (TEC) applicable to that Power Station for that Financial Year. A Power Station should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity, STTEC). For the avoidance of doubt, TNUoS Charges will be determined on the TEC held by a User as specified within a relevant bilateral agreement regardless of whether or not it enters into a temporary TEC Exchange (as defined in the CUSC).

14.18.11 The short-term chargeable capacity for Power Stations situated with positive generation tariffs is any approved STTEC or LDTEC applicable to that Power Station during a valid STTEC Period or LDTEC Period, as appropriate.

14.18.12 For Power Stations, the short term chargeable capacity for LDTEC with positive generation tariffs referred to in Paragraph 14.18.11will be the capacity purchased either on a profiled firm[1] or indicative[2] basis and shall be assessed according to the capacity purchased on a weekly basis. The short-term chargeable capacity for LDTEC in any week may comprise of a number of increments, which shall be determined by considering LDTEC purchased previously in the Financial Year (whether or not in the same LDTEC Period). For example, if in a given week the LDTEC is 200MW but in a previous week the LDTEC had been 150MW, the short-term chargeable capacity in the latter week would comprise of two increments: one of 150MW and a second of 50MW. Further examples are provided in 14.16.6.

Generation with negative wider tariffs

14.18.13 The Chargeable Capacity for Power Stations with negative wider generation tariffs is the average of the capped metered volumes during the three settlement periods described in 14.18.14 below, for the Power Station (i.e. the sum of the

[1] where an LDTEC Block Offer has been accepted (Profiled Block LDTEC) and a firm profile of capacity has been purchased.

[2] where an LDTEC Indicative Block Offer has been accepted (Indicative Profiled Block LDTEC) and a right to future additional capacity up to a requested level has been purchased, the availability of which will be notified on a weekly basis in accordance with the CUSC.

metered volume of each BM Unit associated with Power Station in Appendix C of its Bilateral Agreement). A Power Station should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity). If TEC is exceeded, the metered volumes would each be capped by the TEC for the Power Station applicable for that Financial Year. For the avoidance of doubt, TNUoS Charges will be determined on the TEC held by a User as specified within a relevant bilateral agreement regardless of whether or not it enters into a temporary TEC Exchange (as defined in the CUSC).

14.18.14 The three settlement periods are those of the highest metered volumes for the Power Station and the two half hour settlement periods of the next highest metered volumes which are separated from the highest metered volumes and each other by at least 10 Clear Days, between November and February of the relevant Financial Year inclusive. These settlement periods do not have to coincide with the Triad.

Example

If the highest TEC for a Power Station were **250MW** and the highest metered volumes and resulting capped metered volumes were as follows:

Date	19/11/08	13/12/08	06/02/09
Highest Metered Volume in month (MW)	**245.5**	**250.3**	**251.4**
Capped Metered Volume (MW)	**245.5**	**250.0**	**250.0**

Then, the chargeable Capacity for the Power Station would be:

$$\left(\frac{245.5+250+250}{3}\right) = \mathbf{248.5\ MW}$$

Note that in the example above, the Generator has exceeded its TEC on 13 December 2007 and 6 February 2008 and would therefore be in breach of the CUSC unless the generator had an approved STTEC or LDTEC value. (The STTEC and LDTEC charge for negative zones is currently set at zero).

14.18.15 The short-term chargeable capacity for Power Stations with negative generation tariffs is any approved STTEC or LDTEC applicable to that Power Station during a valid STTEC Period or LDTEC Period, as applicable.

14.18.16 For Power Stations with negative generation tariffs, the short-term chargeable capacity for LDTEC referred to in Paragraph 14.18.15 will be the capacity purchased either on a profiled firm or indicative basis and shall be assessed according to the capacity purchased on a weekly basis. The short-term chargeable capacity for LDTEC in any week may comprise of a number of increments, which shall be determined by considering LDTEC purchased previously in the Financial Year (whether or not in the same LDTEC Period). For example, if in a given week the LDTEC is 200MW but in a previous week the LDTEC had been 150MW, the short-term chargeable capacity in the latter week would comprise of two increments: one of 150MW and a second at 50MW.

14.18.17 As noted above, a negative LDTEC tariff in negative generation charging zones is set to zero. Accordingly no payments will be made for use of LDTEC (in any of its forms) in these zones.

Basis of Local Generation Charges

14.18.18 The Chargeable Capacity for Power Stations will be the same as that used for wider generation charges, except that each component of the local tariff shall be considered separately as to whether it is a positive or negative tariff component. This means that where a local circuit tariff is negative, the final charging liability for this element will be based on actual metered output as described in Paragraph 14.18.12.

Small Generators Charges

14.18.19 Eligible small generators' tariffs are subject to a discount of a designated sum defined by Licence Condition C13 as 25% of the combined residual charge for generation and demand. The calculation for small generators charges is not part of the methodology however, for information the designated sum is included in **The Statement of Use of System Charges.**

Monthly Charges

14.18.20 Initial Transmission Network Use of System Generation Charges for each Financial Year will be based on the Power Station Transmission Entry Capacity (TEC) for each User as set out in their Bilateral Agreement. The charge is calculated as above. This annual TNUoS generation charge is split evenly over the months remaining in the year. For positive final generation tariffs, if TEC increases during the charging year, the party will be liable for the additional charge incurred for the **full** year, which will be recovered uniformly across the remaining chargeable months in the relevant charging year (subject to Paragraph 14.18.21 below). An increase in monthly charges reflecting an increase in TEC during the charging year will result in interest being charged on the differential sum of the increased and previous TEC charge. The months liable for interest will be those preceding the TEC increase from April in year t. For negative final generation tariff, any increase in TEC during the year will lead to a recalculation of the monthly charges for the remaining chargeable months of the relevant charging year. However, as TEC decreases do not become effective until the start of the financial year following approval, no recalculation is necessary in these cases. As a result, if TEC increases, monthly payments to the generator will increase accordingly.

14.18.21 The provisions described above for increases in TEC during the charging year shall not apply where the LDTEC (in any of its forms) has been approved for use before the TEC is available, which will typically mean the LDTEC has been approved after the TEC increase has been approved. In such instances, the party shall commence payments for TEC during the LDTEC Period for LDTEC purchased up to the future level of TEC and LDTEC Charges will only apply to LDTEC that is incremental to the TEC increase. For the avoidance of doubt, where TEC has been approved after LDTEC in a given year, these provisions shall not apply and the LDTEC shall be considered additional to the TEC and charged accordingly.

Ad hoc Charges

14.18.22 For each STTEC period successfully applied for, a charge will be calculated by multiplying the STTEC by the tariff calculated in accordance with Paragraph

14.16.3. The Company will invoice Users for the STTEC charge once the application for STTEC is approved.

14.18.23 For Power Stations utilising LDTEC (in any of its forms) the LDTEC Charge for each LDTEC Period is the sum of the charging liabilities associated with each incremental level of short term chargeable capacity provided by LDTEC within the LDTEC Period (assessed on a weekly basis). The charging liability for a given incremental level of short term chargeable capacity is the sum of:

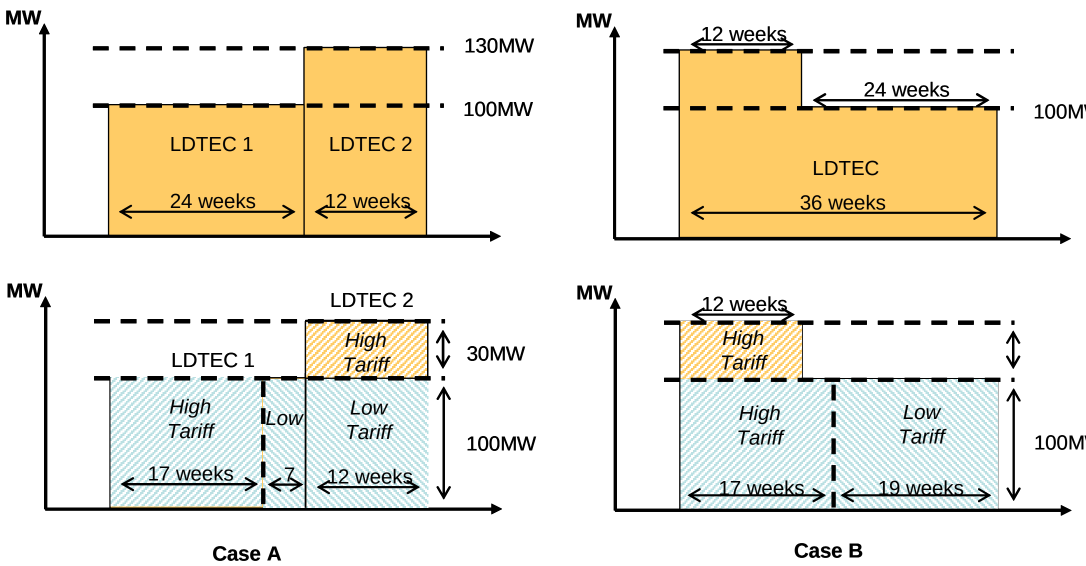
i) the product of the higher tariff rate (calculated in accordance with Paragraph 14.16.6) and capacity purchased at this increment for the first 17 weeks in a Financial Year (whether consecutive or not); and

ii) the product of the lower tariff rate (calculated in accordance with Paragraph 14.16.6) and capacity purchased at this increment in any additional weeks within the same Financial Year (whether consecutive or not).

14.18.24 For each LDTEC Period successfully applied for, the LDTEC Charge will be split evenly over the relevant LDTEC Period and charged on a monthly basis. LDTEC charges will apply to both LDTEC (in any of its forms) and Temporary Received TEC held by a User. For the avoidance of doubt, the charging methodology will not differentiate between access rights provided to a generator by LDTEC or through Temporary Received TEC obtained through a Temporary TEC Exchange (as defined in the CUSC).

<u>Example</u>

The diagrams below show two cases where LDTEC has been purchased: in Case A, two LDTEC Periods have been purchased; and in Case B one LDTEC Period has been purchased. The total capacity purchased in both cases is the same. The top diagrams illustrate the capacity purchased, while lower diagrams illustrate the incremental levels of short term chargeable capacities of LDTEC and the tariff rate that would apply to that capacity.



In both cases, the total amount charged for the LDTEC would be the same:

❑ <u>Capacity charges at the higher tariff rate:</u>

- 17 weeks at the 100MW increment

❑ <u>Capacity charges at the lower tariff rate:</u>

- 19 weeks at the 100MW increment

- 12 weeks at the 30MW increment ❑

Embedded Transmission Use of System Charges "ETUoS"

14.18.25 The ETUoS charges are a component of Use of System charges levied on offshore generators whose offshore transmission connection is embedded in an onshore distribution network. The charge relates to the provision and use of the onshore distribution network.

14.18.26 The main purpose of ETUoS charges is to pass through the charges that are levied by the DNO on the NETSO to the offshore generator(s). This charge reflects the charges levied by the DNO for the costs of any works on and use of the DNO network in accordance with the DNO's charging statements and will include, but is not limited to, upfront charges and capital contributions in respect of any works as well as the ongoing and annual Use of System charges for generation connected to the distribution network.

14.18.27 In the case of some relevant transitional offshore generation projects, ETUoS will also be used to pass through historic DNO capital contributions forming part of the Offshore Transmission Owner tender revenue stream.

14.18.28 The specific nature of the ETUoS charge and the payment profile for these will depend upon the charging arrangements of the relevant DNO and reference should be made to the relevant DNO's charging statement. In terms of applicable transitional offshore generation projects the ETUoS payment profile will be consistent with the recovery of the Offshore Transmission Owner revenue stream.

14.18.29 Where a DNO's charge relates to more than one offshore generator, the related ETUoS charge will represent a straight pass through of the distribution charge specific to each relevant offshore generator. Where specific information is not available, charges will be pro-rated based on the TEC of the relevant offshore generators connected to that offshore network.

14.18.30 Invoices for ETUoS charges shall be levied by The Company on the offshore generator as soon as reasonably practicable after invoices have been received by The Company for payment such that The Company can meet its payment obligations to the DNO. The initial payments and payment dates will be outlined in a User's Construction Agreement and/or Bilateral Agreement.

14.18.31 As the ETUoS charges reflect the DNO charges to The Company, such charges will be subject to variation when varied by the DNO. Where the User disputes regarding the ETUoS charge please note that this will result in a dispute between The Company and DNO under the DCUSA.

Reconciliation of Generation Charges

14.18.32 The reconciliation process is set out in the CUSC and in line with the principles set out above.

14.18.33 In the event of a manifest error in the calculation of TNUoS charges which results in a material discrepancy in a User's TNUoS charge as defined in Sections 14.17.33~~14.17.32~~ to 14.17.35~~14.17.34~~, the generation charges of Users qualifying under Section 14.17.34~~14.17.343~~ will be reconciled in line with 14.18.20 and 14.18.25 using the recalculated tariffs.

Further Information

14.18.34 **The Statement of Use of System Charges** contains the £/kW generation zonal tariffs for the current Financial Year.

14.19 Data Requirements

Data Required for Charge Setting

14.19.1 Users who are Generators or Interconnector Asset Owners provide to The Company a forecast for the following Financial Year of the highest Transmission Entry Capacity (TEC) applicable to each Power Station or Interconnector for that Financial Year. For Financial Year 2008/9 Scottish Generators or Interconnector Asset Owners provide to The Company a forecast of the equivalent highest 'export' capacity figure. This data is required by The Company as the basis for setting TNUoS tariffs. The Company may request these forecasts in the November prior to the Financial Year to which they relate, in accordance with the CUSC. Additionally users who are Generators provide to The Company details of their generation plant type.

14.19.2 Users who are owners or operators of a User System (e.g. Distribution companies) provide a forecast for the following Financial Year of the Natural Demand attributable to each Grid Supply Point equal to the forecasts of Natural Demand under both Annual Average Cold Spell (ACS) Conditions and a forecast of the average metered Demand attributable to such Grid Supply Point for the National Grid Triad. This data is published in table 2.4 of the Seven Year Statement and is compiled from week 24 data submitted in accordance with the Grid Code.

14.19.3 For the following Financial Year, The Company shall use these forecasts as the basis of Transmission Network Use of System charges for such Financial Year. A description of how this data is incorporated is included in 14.15 Derivation of the Transmission Network Use of System Tariff.

14.19.4 If no data is received from the User, then The Company will use the best information available for the purposes of calculation of the TNUoS tariffs. This will normally be the forecasts provided for the previous Financial Year.

Data Required for Calculating Users' Charges

14.19.5 In order for The Company to calculate Users' TNUoS charges, Users who are Suppliers shall provide to The Company forecasts of half-hourly and non-half-hourly demand in accordance with paragraph 14.17.14 and 14.17.15 and in accordance with the CUSC.

14.20 Applications

14.20.1 Application fees are payable in respect of applications for new Use of System agreements; modifications to existing agreements; and applications for short-term access products or services. These are based on the reasonable costs that transmission licensees incur in processing these applications.

Applications for short-term access

14.20.2 Application fees for short-term access products or services are fixed and detailed in the **Statement of Use of System Charges**. These are non-refundable except for the following limited instances:

- Where a User (or Users) withdraw their application in accordance with any interactivity provisions that may be contained within the CUSC; or

- Where the application fee covers ongoing assessment work that is contingent on the acceptance of the offer.

14.20.3 In either case, the refunded amount will be proportional to the remaining assessment time available.

14.20.4 To ensure that application fees for short-term access are cost reflective, fees may be comprised of a number of components. For instance, the LDTEC Request Fee is comprised of a number of components and the total fee payable is the sum of those components that apply to the type(s) of LDTEC Offer(s) requested. For example:

- The LDTEC Request Fee for an LDTEC Block Offer is the basic request fee.

- The LDTEC Request Fee for an LDTEC Indicative Block Offer is the sum of the basic request fee and the additional rolling assessment fee.

- The LDTEC Request Fee payable for a combined LDTEC Block Offer and LDTEC Indicative Block Offer is the sum of the basic request fee, the additional rolling assessment fee, and the additional combined application fee.

Applications for new or modified existing Use of System Agreements

14.20.5 Users can opt to pay a fixed price application fee in respect of their application or pay the actual costs incurred. The fixed price fees for applications are detailed in the **Statement of Use of System Charges**.

14.20.6 If a User chooses not to pay the fixed fee, the application fee will be based on an advance of transmission licensees' Engineering and out-of pocket expenses and will vary according to the size of the scheme and the amount of work involved. Once the associated offer has been signed or lapsed, a reconciliation will be undertaken. Where actual expenses exceed the advance, The Company will issue an invoice for the excess. Conversely, where The Company does not use the whole of the advance, the balance will be returned to the User.

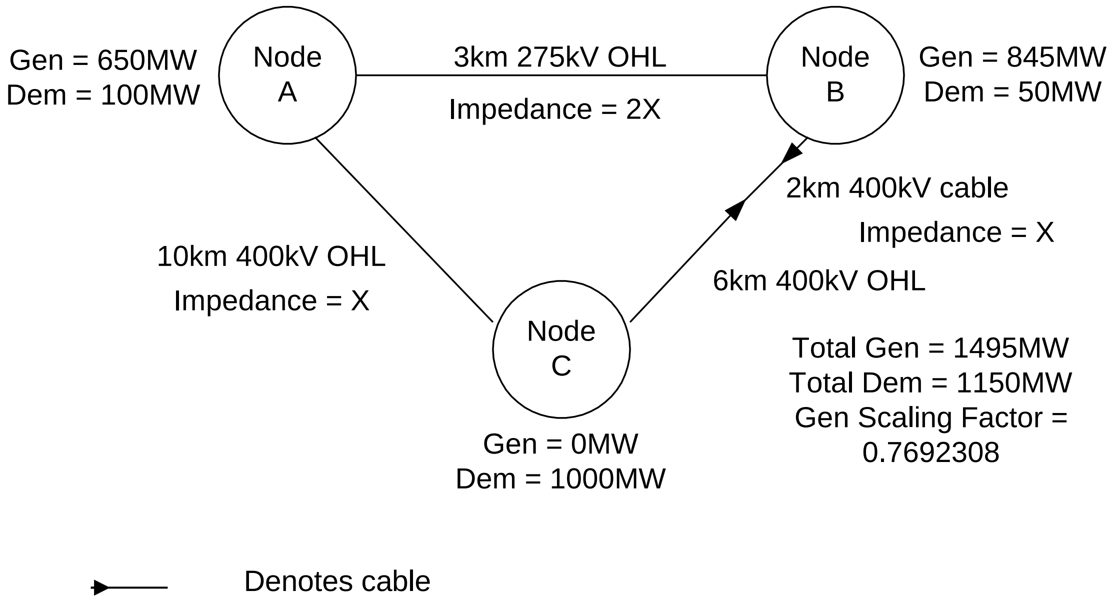
14.20.7 The Company will refund the first application fee paid (the fixed fee or the amount post-reconciliation) and consent payments made under the Construction Agreement for new or modified existing agreements. The refund shall be made either on commissioning or against the charges payable in the first three years of the new or modified agreement. The refund will be net of external costs.

14.20.8 The Company will not refund application fees for applications to modify a new agreement or modified existing agreement at the User's request before any charges become payable. For example, The Company will not refund an application fee to delay the provision of a new connection if this is made prior to charges becoming payable.

14.21 Transport Model Example

For the purposes of the DCLF Transport algorithm, it has been assumed that the value of circuit impedance is equal to the value of circuit reactance.

Consider the following 3-node network, where generation at node A is intermittent and generation at node B is conventional:



For both Peak Security and Year Round generation backgrounds, the nodal generation is scaled according to the relevant Scaling Factors as set out in the Security Standard, such that total system generation equals total system demand.

Peak Security background:

A fixed scaling factor of 0% is applied to intermittent generation at node A and a variable scaling factor is applied to the conventional generation at node B so that the total generation is equal to the total demand.

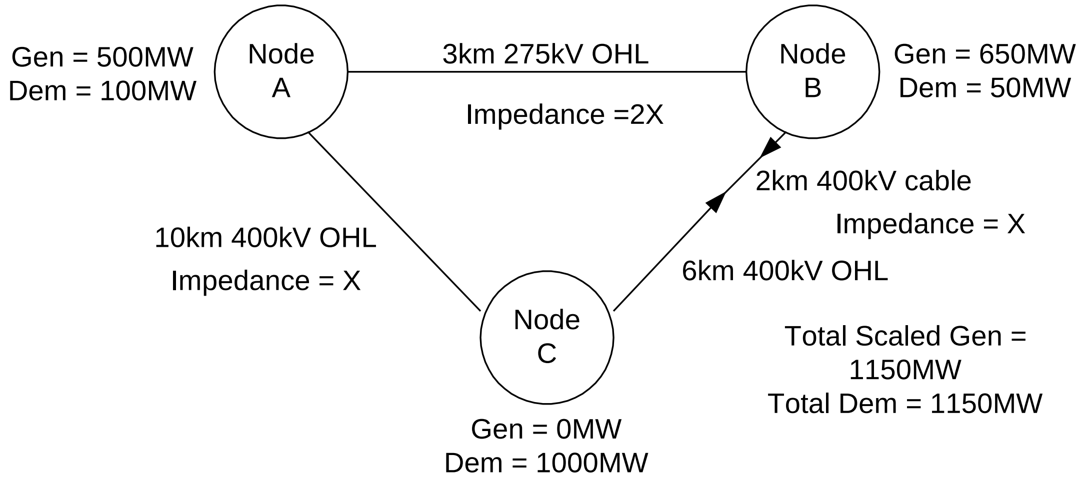
Node A Generation =

0 * 643MW = 0MW

Node B Generation = 1150/

1500 * 1500MW = 1150MW

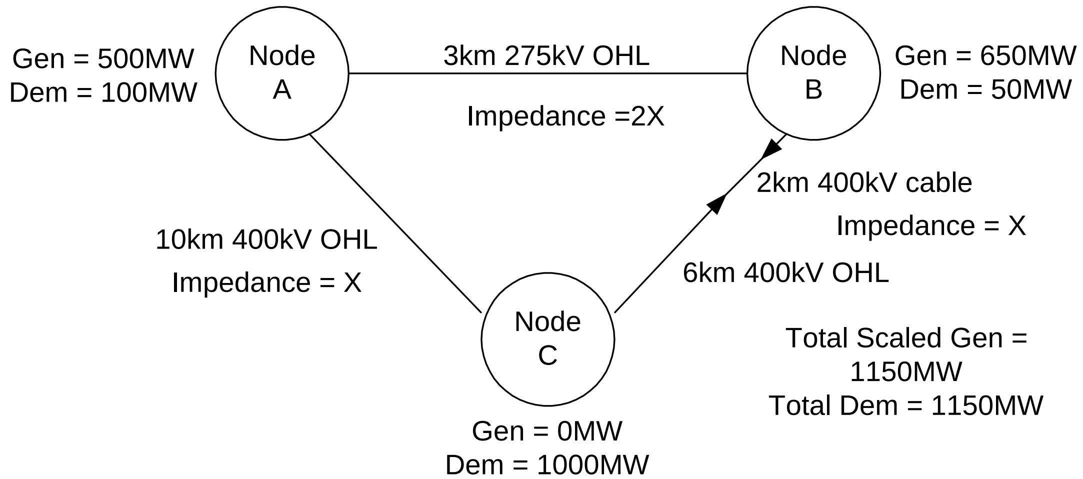
This gives the following balanced system , where the actual generation after the application of scaling factors is shown:



Assuming Node A is the reference node†,, each 400kV circuit has impedance X, the 275kV circuit has impedance 2X, the 400kV cable circuit expansion factor is 10 and the 275kV overhead line circuit expansion factor is 2, the DCLF transport algorithm calculates the base case power flows for Peak Security background as follows:

Node B exports, whilst Nodes A and C import. Hence the DCLF algorithm derives flows to deliver export power from Node B to meet import needs at Nodes A and C.

Step 1: Net export from Node B to Node A is 100MW; both routes BA and BC-CA have impedance 2X; hence 50MW would flow down both routes.



Step 2: Net export from Node B to Node C is 1000MW; route BC has impedance X and route BA-AC has impedance 3X; hence 750MW would flow down BC and 250MW along BA-AC

† For simplicity, fixed reference node has been used instead of a distributed reference node.

Step 3: Using super-position to add the flows derived in Steps 1 and 2 derives the following;

Flow AC	= -50MW + 250MW	=	200MW
Flow AB	= -50MW – 250MW	=	-300MW
Flow BC	= 50MW + 750MW	=	800MW

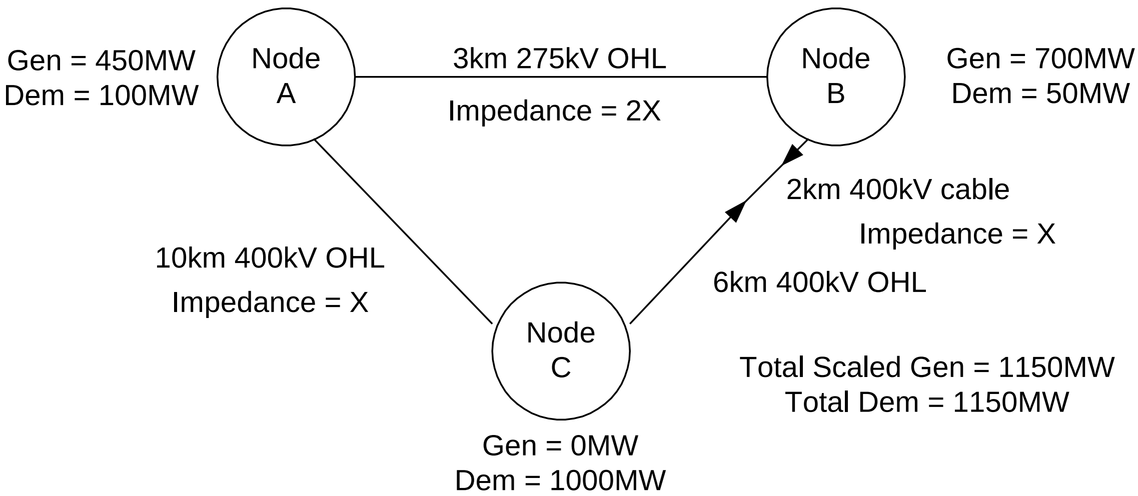
Year Round background:

A fixed scaling factor of 70% is applied to intermittent generation at node A and a variable scaling factor is applied to the conventional generation at node B so that the total generation is equal to the total demand.

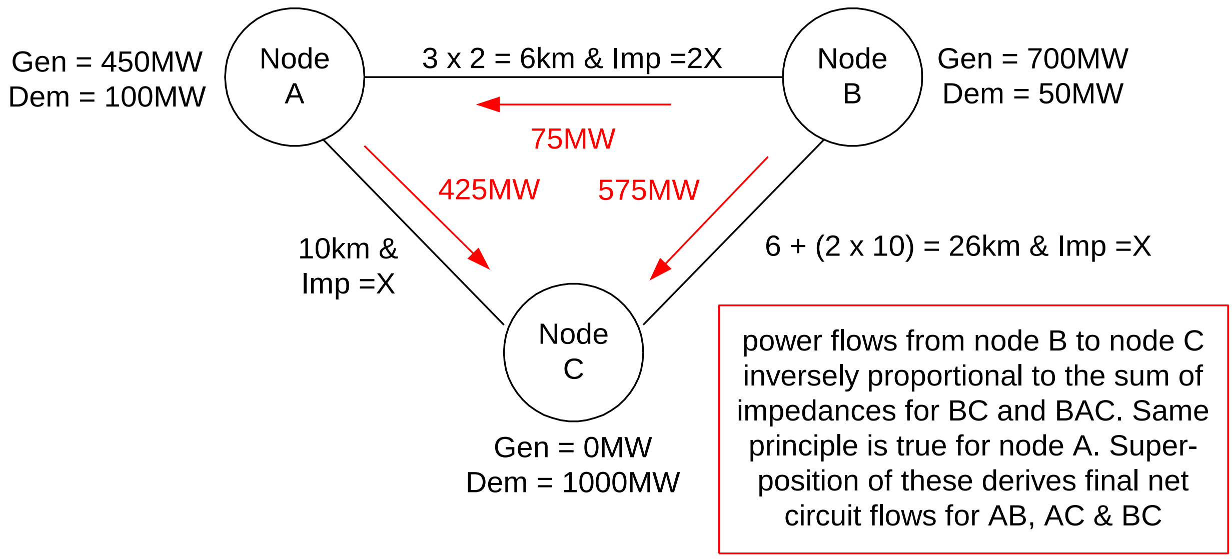
Node A Generation = 70% * 643MW = 450MW

Node B Generation = (1150-450)/1500 * 1500MW = 700MW

This gives the following balanced system, where the actual generation after the application of scaling factors is shown:



Assuming the same circuit impedances and expansion factors as used above in the Peak Security background, the DCLF transport algorithm calculates the base case power flows for Year Round background as follows:



Nodes A and B export, whilst Node C imports. Hence the DCLF algorithm derives flows to deliver export power from Nodes A and B to meet import needs at Node C.

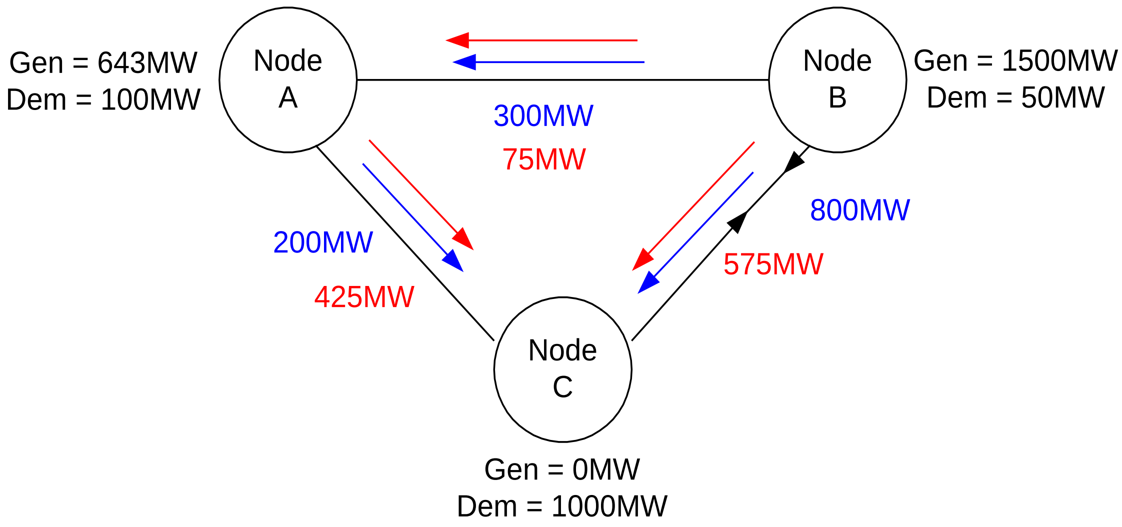
Step 1: Net export from Node A is 350MW; route AC has impedance X and route AB-BC has impedance 3X; hence 262.5MW would flow down AC and 87.5MW along AB-BC

Step 2: Net export from Node B is 650MW; route BC has impedance X and route BA-AC has impedance 3X; hence 487.5MW would flow down BC and 162.5MW along BA-AC

Step 3: Using super-position to add the flows derived in Steps 1 and 2 derives the following;

Flow AC	= 262.5MW + 162.5MW	=	425MW
Flow AB	= 87.5MW – 162.5MW	=	-75MW
Flow BC	= 87.5MW + 487.5MW	=	575MW

Then, based on the background giving rise to highest flow, each circuit is tagged as either Peak Security or Year Round.

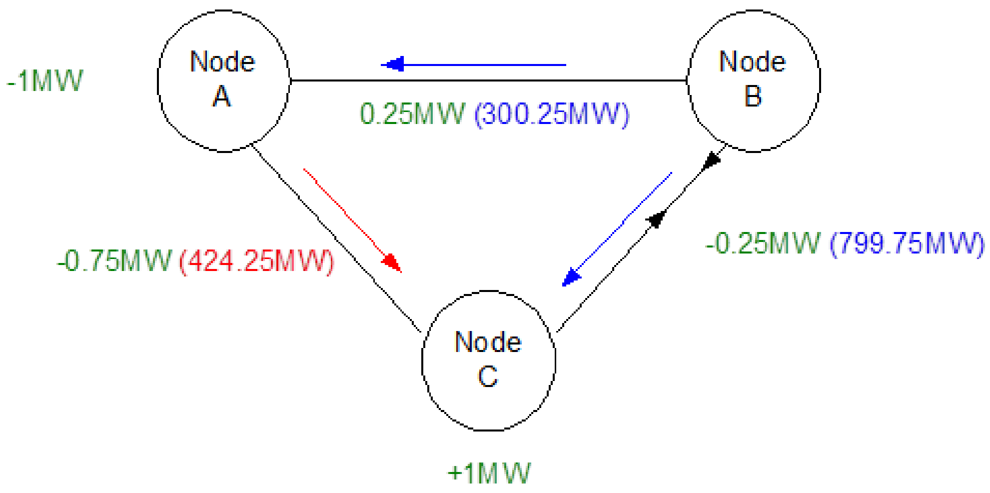


Therefore, circuits AB and BC are tagged as Peak Security and AC is tagged as Year Round.

Total Peak Security cost = (300 X 6) + (800 X 26) = 22,600MWkm
(base case)

Total Year Round cost = 425 X 10 = 4,250 MWkm
(base case)

We then 'inject' 1MW of generation at each node with a corresponding 1MW offtake (demand) at the reference node and recalculate the total Peak Security MWkm cost and Year Round MWkm cost (noting that each circuit is only in one background). The difference from the base case for Peak Security and Year Round costs is the marginal km or shadow cost for Peak Security and Year Round networks respectively. The size and direction of the incremental MW is shown below along with the resultant when superimposed on the relevant base case flow (i.e. higher of the Peak Security and Year Round) depicted in brackets:.



To calculate relevant Peak Security and Year Round the marginal km for node C:

Total Peak Security Cost = (300.25 x 6) + (799.75 x 26) =22,595

Total Year Round Cost = 424.25 X 10 = 4,242.5 MWkm

Marginal Peak Security cost = Incremental total Peak Security cost – Base case total Peak Security cost

= 22595 – 22600 = -5MWkm

Marginal Year Round cost = Incremental total Year Round cost – Base case total Year Round cost

= 4242.5 – 4250 = -7.5MWkm

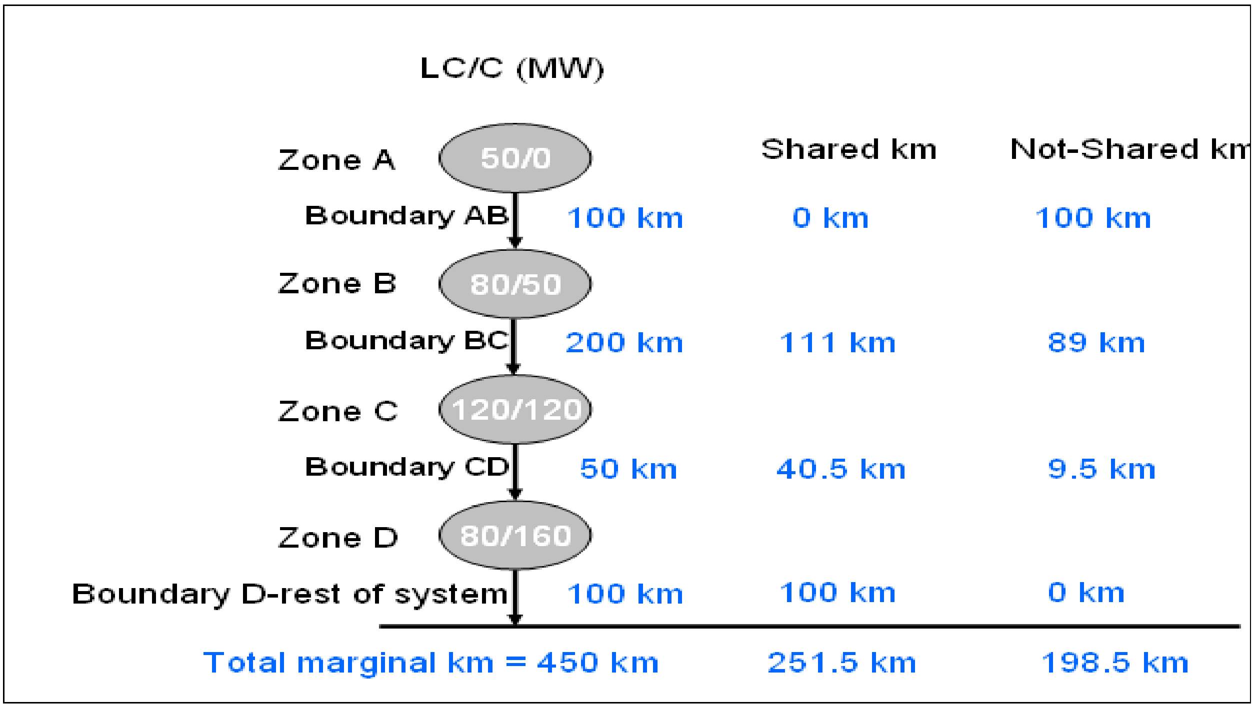
Thus the overall cost has reduced by .5 for Peak Security (i.e. the marginal km = 5) and by 7.5 for Year Round (i.e the Year Round marginal km = -7.5)

14.22 Illustrative Calculation of Boundary Sharing Factors (BSFs) and Shared / Not-Shared incremental km

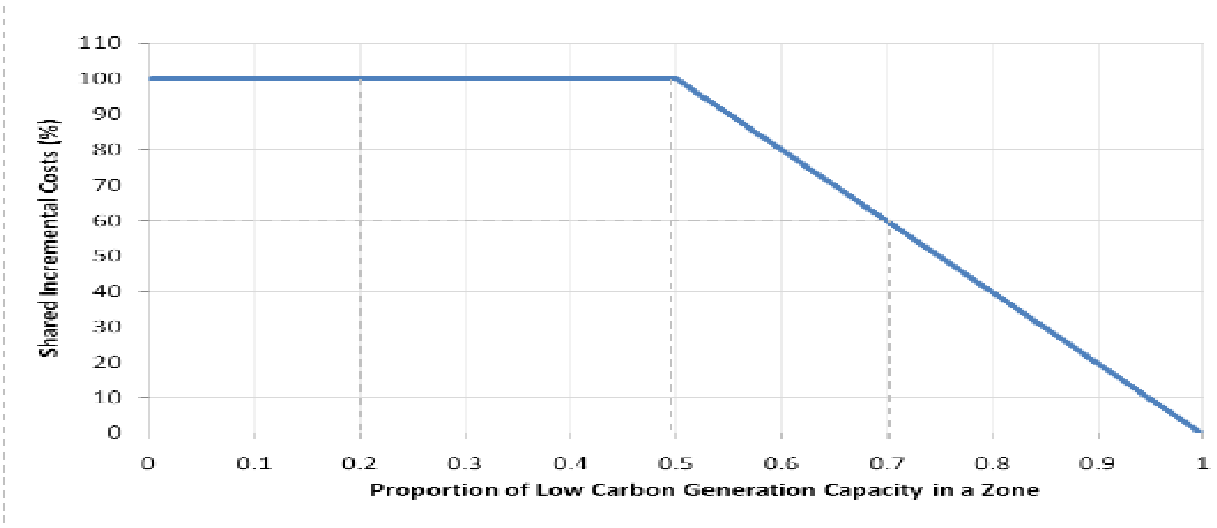
The following illustrative example shows how the boundary sharing factors and shared / not-shared incremental km are calculated for the transmission system described in the table below.

Generation Charging Zone	A	B	C	D
Zonal MWkm	450	350	150	100

The digram below shows the expanded connectivity of this transmission system.



up



The above figure illustrates how the Year Round marginal km are split into Shared and Not-Shared.

(a) For Boundary AB (where 50MW of the generation is Low Carbon (LC) and 0MW of the generation is Carbon (C) and Year Round boundary marginal km = 100km) -

$\frac{LC}{(LC+C)} = \frac{50}{50+0} = 1$ which is greater than 0.5, therefore the following formula will be used to calculate the Boundary Sharing Factor (BSF) –

$$BSF = -2 \times \left(\frac{LC}{LC+C} \right) + 2 \ = \ -2 \times \left(\frac{50}{50+0} \right) + 2 = 0 \ (0\%)$$

Year Round Shared marginal km = 0.0 * 100km = 0 km
Year Round Not-Shared marginal km = (100 – 0)km = 100 km

(b) For Boundary BC (where 130MW of generation is Low Carbon (LC) and 50MW of generation is Carbon (C) and Year Round boundary marginal km = 200km) –

$\frac{LC}{(LC+C)} = \frac{(50+80)}{(50+80)+(0+50)} = 0.722$ which is greater than 0.5, therefore the following formula will be used to the BSF –

$$BSF = -2 \times \left(\frac{LC}{LC+C} \right) + 2 \ = \ -2 \times \left(\frac{130}{130+50} \right) + 2 = \ 0.556 \ (55.6\%)$$

Year Round Shared marginal km = 0.556 * 200km = 111 km
Year Round Not-Shared marginal km = (200 – 111)km = 89 km

(c) For Boundary CD (where 250MW of generation is Low Carbon (LC) and 170MW of generation is Carbon (C) and Year Round boundary marginal km = 50km) –

$\frac{LC}{(LC+C)} = \frac{(50+80+120)}{(50+80+120)+(0+50+120)} = 0.595$ which is greater than 0.5, therefore the following formula will be used to calculate the BSF –

$$BSF = -2 \times \left(\frac{LC}{LC+C} \right) + 2 \ = \ -2 \times \left(\frac{250}{250+170} \right) + 2 = 0.810 \ (81\%)$$

Year Round Shared marginal km = 0.81 * 50km = 40.5 km
Year Round Not-Shared marginal km = (50 – 40.5)km = 9.5 km

(d) For Doundary D-rest of system (where 330MW of generation is Low Carbon (LC) and 330MW of generation is Carbon (C) and Year Round boundary marginal km = 100km) –

$\frac{LC}{(LC+C)} = \frac{(50+80+120+80)}{(50+80+120+80)+(0+50+120+160)} = 0.5$ therefore it is at the threshold at which maximum sharing occurs between LC and C generation. Therefore 100% of the Year Round zonal marginal km will be shared. (i.e. BSF=1.0);

Year Round Shared marginal km = 1.0 * 100 = 100 km
Year Round Not-Shared marginal km = (100 – 100)km = 0 km
The shared zonal marginal km for each generation charging zone will be the sum of the relevant shared boundary marginal km as shown in the table below (assuming the node below D is the

centre of the system i.e. zonal MWkm of 0). These not-shared zonal incremental km are then use to calculate wider £/kW generation tariffs.

Boundary/Zone	**A**	**B**	**C**	**D**
A-B	0			
B-C	111	111		
C-D	40.5	40.5	40.5	
D-rest of system	100	100	100	100
Shared Zonal MWkm	251.5	251.5	140.5	100
Total Zonal MWkm	450	350	150	100

The not-shared zonal marginal km for each generation charging zone will be the sum of the relevant not-shared boundary marginal km as shown in the table below (assuming the node below D is the centre of the system i.e. zonal MWkm of 0). These not-shared zonal incremental km are then use to calculate wider £/kW generation tariffs.

Boundary/Zone	**A**	**B**	**C**	**D**
A-B	100			
B-C	89	89		
C-D	9.5	9.5	9.5	
D-rest of system	0	0	0	0
Not-Shared Zonal MWkm	198.5	98.5	9.5	0
Total Zonal MWkm	450	350	150	100

14.23 Example: Calculation of Zonal Generation Tariff

Wider
Let us consider all nodes in a generation zone in this example.

The table below shows a sample output of the transport model comprising the node, the Peak Security wider nodal marginal km and Year Round wider nodal marginal km (observed on non-local assets) of an injection at the node with a consequent withdrawal across distributed reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand, for both Peak Security and Year Round generation backgrounds..

Gen Zone	Node	Wider Nodal Marginal km (Peak Security)	Scaled Generation (Peak Security)	Wider Nodal Marginal km (Year Round)	Scaled Generation (Year Round)
4	ABNE10	5.73	0.00	459.90	0.00
4	CLAY1S	239.67	0.00	306.47	0.00
4	CLUN1S	46.41	22.90	502.16	18.76
4	COUA10	45.39	0.00	423.30	0.00
4	DYCE1Q	162.70	0.00	357.81	0.00
4	ERRO10	46.82	56.13	534.03	45.99
4	FIDD1B	91.88	0.00	220.59	0.00
4	FINL1Q	79.69	12.35	495.63	10.12
4	GRIF1S	33.31	0.00	521.16	71.40
4	KIIN10	79.69	0.00	495.63	0.00
4	LOCH10	79.69	35.18	495.63	28.82
4	MILC10	117.69	0.00	328.86	0.00
4	PERS20	266.00	0.00	384.05	0.00
4	TUMB1Q	46.82	0.00	536.27	0.00
		Totals	**126.56**		**175.09**

In order to calculate the generation tariff we would carry out the following steps.

(i) calculate the generation weighted wider nodal shadow costs.

For this example zone this would be as follows:

Gen Zone	Node	Wider Nodal Marginal km (Peak Security)	Scaled Generation (Peak Security) (MW)	Gen Weighted Wider Nodal Marginal km (Peak Security)	Wider Nodal Marginal km (Year Round)	Scaled Generation (Year Round) (MW)	Gen Wei Wider Margin (Year R
4	CLUN1S	46.41	22.90	8.39	502.16	18.76	5
4	ERRO10	46.82	56.13	20.76	534.03	45.99	14
4	FINL1Q	79.69	12.35	7.77	495.63	10.12	2
4	GRIF1S	N/A	N/A	N/A	521.16	71.40	21
4	LOCH10	79.69	35.18	22.15	495.63	28.82	8
		Totals	**126.56**			**175.09**	

i.e. $\frac{79.69 \times 35.18}{126.56}$

(ii) sum the generation weighted wider nodal shadow costs to give Peak Security and Year Round zonal figures

For this example zone this would be:

.**Peak Security**: (8.39 + 20.76+7.77+22.15) km = **59.07km**
Year Round: (53.80 + 140.27 + 28.65 + 212.52 + 81.58) = **516.82 km**

(iii) In this example we have assumed that accounting for sharing in the Year Round background gives:

Year Round Shared marginal km = 344.56km
Year Round Not-Shared marginal km = 172.26km

)

(iv) calculate the initial Peak Security wider transport tariff, Year Round Shared wider transport tariff and Year Round Not-Shared wider transport tariff by multiplying the figure in (iii) above by the expansion constant (& dividing by 1000 to put into units of £/kW).

For zone 4 and assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.8:

(a) Initial Peak Security wider tariff - $\frac{59.07 \text{ km} * £10.07/\text{MWkm} * 1.8}{1000}$ = **£1.071/kW**

b) Initial Year Round Shared wider tariff -

$\frac{344.56 \text{ km} * £10.07/\text{MWkm} * 1.8}{1000}$ = **£6.245/kW**

c) Initial Year Round Not-Shared wider tariff -

$$\frac{172.26\ km * £10.07/MWkm * 1.8}{1000} = \mathbf{£1.309/kW}$$

Local

(v) If we assume (for the sake of this example) that the generator connecting at CLUN1S is a thermal plant with a Peak Security flag of 1 and an Annual Load Factor (ALF) of 60%, which connects via 10km of 132kV 100MVA rated single circuit overhead line from the nearest MITS node, with no redundancy, the substation is rated at less than 1320MW, and there is no other generation or demand connecting to this circuit, then:

a) referencing the table in paragraph 14.15.118, the local substation tariff will be £0.133/kW; and

b) running the transport model with a local circuit expansion factor of 10.0 applied to the 10km of overhead line connecting CLUN1S to the nearest MITS node and the wider circuit expansion factors applied to all other circuits, gives a local nodal maginal cost of 100MWkm. This is the additional MWkm costs associated with the node's local assets. Applying the expansion constant of £10.07/MWkm and local security factor of 1.0 and dividing by 1000 gives a local circuit tariff of £1.007/kW.

Adjustment Tariff
~~Residual~~

~~(vi)~~ We now need to calculate the Adjustment~~residual~~ tariff. This is calculated by taking the Adjustment Revenue and dividing this by the Chargable Generation Capacity (as per 14.14.5(ii) and 14.14.5(iii)) to create a £/kW figure~~total revenue to be recovered from generation (calculated as c.27% of total The Company TNUoS target revenue for the year) less the revenue which would be recovered through the generation transport tariffs divided by total expected generation.~~

(vi)

Assuming annual transmission charges paid by generators is due to fall below €0, The Company will add Adjustment Revenue to ensure the Limiting Regulation is not breached – in this example let us assume it is £260m and the GB-wide generation Chargable Capacity is 60GW (60,000,000kW). This would mean the non-locational Adjustment Tariff would be calculated as;

$$Adjustment\ Tariff\ (AdjTariff) = \frac{Adjustment\ Revenue}{Chargable\ Capacity}$$

$$Adjustment\ Tariff\ (AdjTariff) = \frac{£260m}{60{,}000{,}000kW}$$

$$Adjustment\ Tariff\ (AdjTariff) = £4.33/kW$$

~~Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from generation would be (27% x £1067m) = £288m. Assuming the total recovery from both wider generation transport tariffs (i.e. wider Peak Security tariff, wider Year Round Shared tariff and wider Year Round Not-Shared tariff) and local generation tariffs (i.e. local substation tariff and local circuit tariff) is £70m and total forecast chargeable generation capacity is 67000MW, the Generation residual tariff would be as follows:~~

$$\frac{£288 - £70m}{65000MW} = £3.35/kW$$

(vii) Therefore the charges for thermal plant with a TEC of 100MW and an ALF of 60%, connecting at CLUN1S is:

= Wider Peak Security Tariff * PS Flag * TEC = 1.071 * 1 * 100,000

= Wider Year Round Shared Tariff * ALF * TEC = 6.245 * 0.6 * 100,000

= Wider Year Round Not-Shared Tariff * TEC = 1.309 * 100, 000
= Local substation Tariff * TEC = 0.133 * 100,000

= Local circuit Tariff * TEC = 1.007 * 100,000
= ~~Residual~~ Adjustment Tariff * TEC = 4.33 * 100,000

~~For this example~~
~~, the above changes are -~~

~~= 1.071 * 1 * 100,000~~
~~= 1.309 * 100, 000~~
~~= 0.133*100,000~~
~~= 1.007 * 100,000~~

~~= 3.35 * 100,000~~

(effectively, £11~~0~~.~~617~~~~767~~597/kW * 100,000kW = £1,159~~061~~~~076,~~,700)

(viii) Alternatively, if we assume that the generator connecting at CLUN1S is an intermittent wind generation plant (instead of a thermal plant) with a TEC of 100MW, PS Flag of 0 and an ALF of 30%, then the charges payable will be –

~~= 1.071 * 0 * 100,000~~
~~= 6.245 * 0.3 * 100,000~~
~~= 1.309 * 100,000~~
~~= 0.133 * 100,000~~
~~= 1.007 * 100,000~~
~~= 3.35 * 100,000~~
= Wider Peak Security Tariff * PS Flag * TEC = 1.071 * 0 * 100,000
= Wider Year Round Shared Tariff * ALF * TEC = 6.245 * 0.3 * 100,000
= Wider Year Round Not-Shared Tariff * TEC = 1.309 * 100, 000
= Local substation Tariff * TEC = 0.133 * 100,000
= Local circuit Tariff * TEC = 1.007 * 100,000
= Adjustment Tariff * TEC = 4.33 * 100,000

(effectively, £8.653/kW * 100,000kW = £865,300)

14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in the same demand zone in this example

The table below shows an example output of the transport model comprising the node, the Peak Security and Year Round nodal marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

Where the Demand (MW) is negative this indicates that the Demand node is Exporting rather than importing.

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Demand (MW)
1	A	110	80	100
1	B	140	90	100
1	C	120	80	0
1	D	100	100	-50
1	E	100	70	50
		Totals		**200**

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Net Demand (MW)
14	ABHA4A	-77.25	-230.25	127
14	ABHA4B	-77.27	-230.12	127
14	ALVE4A	-82.28	-197.18	100
14	ALVE4B	-82.28	-197.15	100
14	AXMI40_SWEB	-125.58	-176.19	97
14	BRWA2A	-46.55	-182.68	96
14	BRWA2B	-46.55	-181.12	96
14	EXET40	-87.69	-164.42	340
14	HINP20	-46.55	-147.14	0
14	HINP40	-46.55	-147.14	0
14	INDQ40	-102.02	-262.50	444
14	IROA20_SWEB	-109.05	-141.92	462
14	LAND40	-62.54	-246.16	262
14	MELK40_SWEB	18.67	-140.75	83
14	SEAB40	65.33	-140.97	304
14	TAUN4A	-66.65	-149.11	55
14	TAUN4B	-66.66	-149.11	55
		Totals		**2748**

In order to calculate the gross demand tariff we would carry out the following steps:

(i) Change Negative Demand values to 0 (zero) , which in this example is Node D

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Demand (MW)
1	A	110	80	100
1	B	140	90	100
1	C	120	80	0
1	D	100	100	0
1	E	100	70	50
		Totals		**250**

(ii) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

Demand Zone	Nod e	Peak Security Nodal Marginal km	Year Round Nodal Margina l km	Demand (MW)	Peak Security Demand Weighted Nodal Marginal km	Year Round Demand Weighted Nodal Marginal km
1	A	110	80	100	44	32
1	B	140	90	100	56	36
1	C	120	80	0	0	0
1	D	100	100	0	0	0
1	E	100	70	50	20	14
		Totals		**250**	**120**	**82**

(iii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 120km for Peak Security background and 82km for Year Round background.

(iv) calculate the transport (locational) tariffs by multiplying the figures in (ii) above by -1. This changes the original Nodal Marginal Km for injecting (Generation) into Nodal Marginal Km for withdrawing (Demand). Then multiply by the expansion constant, the locational security factor and then divide by 1000 to put into units of £/kW:

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$-\frac{(120\text{km} * £10.07/\text{MWkm} * 1.8)}{1000} = -\mathbf{£2.47/kW}$$

b) Year Round tariff -

$$-\frac{(82 * £10.07/\text{MWkm} * 1.8)}{1000} = -\mathbf{£1.49/kW}$$

The Locational signal for Demand within this zone is negative for both Peak and Year Round, which indicates withdrawing at this part of the network, reduces total system flows.

(v) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand ~~(calculated as c.73% of total The Company TNUoS target revenue for the year)~~ less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from ~~TNUoS is £1067m, the total recovery from~~ gross GSP group demand ~~would be (73% x £1067m)~~ = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(vi) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 1:

-£2.47/kW + -£1.49/kW + £12.98/kW = **£9.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.