CONSULTATION APPENDICES DOCUMENT

Illustrative Revised Draft of The Statement of the Use of System Charging Methodology

Incorporating:

(i) Proposal to Amend the Methodology for Calculation of Locational TNUoS Tariffs (UoSCM-M-10)

(ii) Introduction of year Round TNUoS Charges (UoSCM-M-11)

12 September 2003

Appendix 1 – Proposed Changes to General Introduction

General Introduction

Licence Condition Objectives

1 The Use of System Charging Methodology, has the following objectives as set out in Licence Condition C7A which requires:

(a) that compliance with the Use of System Charging Methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

(b) that compliance with the Use of System Charging Methodology results in charges which reflect, as far as reasonably practicable, the costs incurred by the licensee in its transmission business; and

(c) that, so far as is consistent with sub-paragraphs (a) and (b), the Use of System Charging Methodology, as far as is reasonably practicable, properly takes account of the developments in the licensee's transmission business.

2 The Licence notes that National Grid must keep the Use of System Charging Methodology under review at all times for the purpose of ensuring that the methodology meets the relevant objectives outlined above.

3 National Grid may make modifications to the Methodology as may be required for the purpose of better meeting the relevant objectives above.

4 Before making those modifications, unless it has been agreed otherwise with the Authority, National Grid will consult with CUSC parties for a period of at least 28 days on the proposed change in the Use of System Charging Methodology where written representations can be made.

5 A report will then be issued to the Authority setting out the terms of the modification, representations made, any change to the terms of the modification, how the modification better meets the relevant objectives and a timetable and date for implementation of the modification.

6 Unless the Authority has, within 28 days of the report being furnished to it, given a direction that the modification may not be made, National Grid will make the modification to the Use of System Charging Methodology.

7 If the proposed change in the Use of System Charging Methodology would result in changes to the Transmission Network Use of System charges, National Grid must give, except where the Authority consents to a shorter period, 150 days notice of a proposal to change Transmission Network Use of System charges to the Authority together with a reasonable assessment of the effect of the proposal on those charges. National Grid will notify Users of the proposal at the same time as the Authority.

8 In addition, with the approval of the Authority, National Grid may alter the form of the statements from time to time and also revise the statements such that the information set out is accurate in all material respects.

The Connection/Transmission Use of System Boundary

9 In order to calculate Transmission Network Use of System charges and Connection charges, National Grid must apportion its assets to one of two charging categories. The apportionment methodology between Connection and Transmission Network Use of System used by National Grid is on a **super shallow** '~~Generation Only Spurs~~**PLUGS**' basis as described by **NGC in its CCM-M-07 Connection Charging Methodology Modification document of 22 August 2003**~~the DGES in his Price Control Proposals Document of 3 October 1996~~. Further details are provided in the **Statement of the Connection Charging Methodology.**

The Contractual Framework

10 The Connection and Use of System Code (CUSC) is a multi-party document creating contractual obligations among and between all Users of the transmission system, parties connected to the transmission system and National Grid. Persons wishing to use and/or connect to the transmission system will normally be required to accede to the CUSC by signing the Framework Agreement and to enter into a Bilateral Agreement with National Grid.

11 National Grid continues to request that Small Power Stations should make a formal application for use of the system to National Grid. National Grid can then assess the potential impact on the transmission system and consider what form of agreement, if any, may be required.

12 The CUSC and individual User's Bilateral Agreements set out the terms and conditions applicable for use of and/or connection to the transmission system. In particular, they set out the User's obligations to:

- pay all use of system and connection charges;
- comply with the provisions of the Grid Code;
- normally sign on to the Balancing and Settlement Code (BSC);
- normally enter into an appropriate Mandatory Services Agreement.

13 Additionally, each Bilateral Agreement details the information on which the User's connection charges are based.

- Appendix A of each Bilateral Agreement lists the connection assets by description, age and allocation to the User;
- Appendix B identifies the connection charges;

14 If a User fails to fulfil their obligations, their entitlement to use and/or be connected to the transmission system will cease. The User will be liable for all charges that may arise up to the end of the current Financial Year and, for connection, the appropriate termination sum.

15 When a User applies for a new use of system agreement or to modify an existing use of system agreement they may be required to enter into a Construction Agreement. Within the Construction Agreement there will be provisions for site specific elements such as Consents and Final Sums.

Appendix 2 - Proposed Changes to Chapter 1: Principles

Chapter 1: Principles

1.1 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner Activity function of the Transmission Business. These activities are undertaken to the standards prescribed by National Grid's Transmission Licence, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

1.2 A Maximum Allowed Revenue (MAR) for these activities and those associated with pre-vesting connections is set by the Authority at the time of National Grid's Transmission Owner (TO) 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 (allowing for any Kt adjustment for under or over recovery in a previous year) net of the income recovered through Pre-Vesting connection charges.

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

1.4 As a result of National Grid's acceptance of the price control proposals made by the Director General of Electricity Supply (DGES) on 3 October 1996, there were further changes to the original methodology, namely:

~~?~~**i.)** The 25:75 split of Transmission Network Use of System charges between Generators and Suppliers was adjusted to approximately 27:73 in order to maintain the 1996/97 balance of overall transmission revenue.~~ This split has been maintained.~~

~~?~~**ii.)** The scaling of generation Transmission Network Use of System charges by the ratio between peak Average Cold Spell (ACS) demand and Genset Registered Capacity was ceased;

~~?~~**iii.)** The number of Transmission Network Use of System generation zones was increased to 16 from the previous 14;

~~?~~**iv.)** The number of Transmission Network Use of System demand zones was reduced to 12 from the previous 14, corresponding to the 12 GSP Groups.

1.5 Further changes were made in April 2000 with regard to the charging basis for non-half hourly metered demand with the introduction of an energy consumption tariff (p/kWh).

1.6 From April 2001 further changes were implemented.

i.) Following a review of the generation zones against the original criteria used in 1996/7 and set out in paragraph 2.19 the number of generation zones was reduced to 15.

ii.) The scaling of demand between metered Triad demand and ACS demand was stopped.

1.7 In October 2003, following an extensive review of charging methodologies conducted by National Grid in consultation with users, a number of further proposed changes were approved by Ofgem and introduced with effect from April 2004. Specifically these were;

i.) The introduction of a DCLF based transport model

ii.) The introduction of multi-voltage circuit expansion factors with a forward looking Expansion Constant, which does not include substation costs in its derivation

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

iv.) The introduction of a "year round" charging structure, namely applying 90% of TNUoS charges on peak as previously and 10% of charges on a year round commodity charge basis

v.) Following a review of the generation zones against the original criteria as set out in paragraph 2.20, the number of zones was increased [?].

vi.) Following the change in connection/infrastructure boundary as referred to in paragraph 9 of the General Introduction, the split of Transmission Network Use of System charges between Generators and Suppliers was adjusted to maintain a 25:75 balance of recovery of overall transmission revenue from generation and demand.

~~1.7~~**1.8** These changes have not, however, **fundamentally** affected the underlying rationale behind Transmission Network Use of System charges. In summary this 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 National Grid 's costs if they were to increase or decrease their use of the system. 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.

1.8 The Transmission Licence requires National Grid to plan, develop and operate the transmission system to specified standards. This requirement means that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to 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, National Grid must ensure that it satisfies the requirements of the Security Standard.

1.9 The Security Standard identifies requirements on the capacity of component sections of the system given the registered capacity of generation and expected demand at each node at peak. The derivation of the incremental investment costs at different points on the system are therefore determined against the requirements of the system at the time of peak demand. The charging methodology therefore recognises this peak element in its rationale.

1.10 **However, National Grid has introduced the "year round" charging structure to reflect the fact that increasingly more transmission investment is made to meet requirements other than peak. This is due to changes in the market background and behaviour and the consequent need for some non-peak transmission investment to accommodate this. Thus whilst the major part (90%) of National Grid's charges remain consistent with the original peak investment rationale from 1993/94, a minor part (10%) now reflects year round costs imposed by market participants on National Grid's transmission investment.**

~~1.10~~**1.11** In setting and reviewing these charges National Grid 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.

Appendix 3: Proposed Changes to Chapter Derivation of Transmission Network Use of System Tariff

Chapter 2: Derivation of the Peak Transmission Network Use of System Tariff

2.1 The **Peak** Transmission Network Use of System (TNUoS) Tariff **recovers 90% of National Grid's allowed total TNUoS recovery and** comprises two separate elements. Firstly, a locationally varying element derived from the 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 ~~security and~~ residual revenue recovery. The combination of both these elements forms the **Peak** TNUoS tariff. The process for calculating the **Peak** TNUoS tariff is described below.

The Transport Model

Model Inputs

2.2 The **DCLF** ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

2.3 The transport model requires a set of inputs representative of peak conditions on the transmission system:

- Nodal generation information
- Nodal demand information
- ~~Allowable t~~**T**ransmission **circuits**~~routes~~ between these nodes ~~(i.e. existing wayleaves)~~
- The associated lengths of these routes and the length of which is overhead line or cable **and their voltage level**
- ~~Whether any of the overhead line / cable routes are charged for via connection charges as generation only spurs~~
- The ratio of **each of 275kV overhead line, 275kV cable and 400kV cable to 400kV overhead line**~~cable to overhead line~~ costs **to give circuit expansion factors**
- Routes with significant spare capacity
- Identification of a reference node.

2.4 The nodal generation data for the transport model for charging year "t" is taken as the **Transmission Export Capacity (TEC)**~~Registered Capacity~~, at each node (based on the forecast for year "t" in the April Seven Year Statement in year "t-1" plus updates to the October of year "t-1"). The forecasts in the Seven Year Statement include all plant belonging to generators who have a Bilateral Connection Agreement with National Grid. For example for 200~~1~~**4**/0~~2~~**5** charges, the nodal generation data is based on the forecast for 200~~1~~**4**/0~~2~~**5** in the April 200~~0~~**3** Seven

Year Statement plus any data included in the quarterly updates to October 200~~0~~**3**). ~~For 2003/04, the derivation of TNUoS tariffs was based on Registered Capacity, as at the time of tariff setting, no TEC data was available. It is proposed to change the nodal data used in tariff setting to utilise TEC to calculate tariffs applicable from April 2004 onwards.~~

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

2.6 Transmission **circuits**~~routes~~ for charging year "t" are defined as th**os**e **with** existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain **circuit**~~route~~ information is not explicitly contained in the Seven Year Statement, National Grid will use the best information available.

2.7 The **circuit**~~route~~ lengths included in the transport model are solely those which relate to assets defined as 'use of system' assets (see the discussion on the Connection/ Use of System Boundary in the General Introduction).

~~2.8For generation only spur routes, the proportion of the circuit length not allocated to the connection will be allocated to TNUoS and will therefore be taken into account in the transport model. This will ensure charges relating to generation only spurs are levied correctly between connection and use of system charges.~~

~~2.9~~**2.8** The **circuit expansion**~~cable~~ factor**s** reflect~~s~~ the difference in cost between **(i)** cabled routes and overhead line routes**, (ii) 275kV routes and 400kV routes, and (iii) uses 400kV overhead line as the base (i.e. 400kV overhead line circuit expansion factor=1)**. As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in **these other types of circuit**~~cabled routes~~ **(specifically 400kV cable, 275kV overhead line and 275kV cable)** is more expensive **than for 400kV overhead line**. This is done by effectively 'lengthening' the**se** ~~cabled~~ **more expensive circuits**~~routes~~ by the **relevant circuit expansion**~~cable~~ factor. This makes them more expensive for the model to use and hence reflects the additional costs of investing in these **circuits**~~routes~~ **compared to 400kV overhead line**.

~~2.10~~**2.9** **Circuits**~~Routes~~ **that**~~which~~ are identified as having spare capacity, for the purposes of the transport model, are assumed to be less costly to invest in as there is a buffer before new investment would be required. This is modelled in the transport model by reducing the length of these routes to 75% of the original length to reflect the reduced cost of expansion. This is equivalent to applying 75% of the expansion constant.

~~2.11~~**2.10** A reference node is required as a basis point for the calculation of marginal costs. It determines the magnitude of the marginal costs but not the relativity. For example, if the reference point were put in the North of the country, all nodal generation marginal costs would likely be negative. Conversely, if the reference point were defined at Land's End, all nodal generation marginal costs would be positive. However the relativity of costs between nodes would stay the same. For the purposes of ICRP, the reference node is **forced**~~assumed~~ to be at Pelham GSP.

Model Outputs

~~2.12~~**2.11** The transport model takes the inputs described above and firstly scales the nodal generation capacity uniformly such that total national **generation** ~~Registered Capacity~~ equals total national ACS Demand. The model then uses a **DCLF ICRP** transport algorithm to **derive the resultant pattern of flows based on the network impedance required to meet the nodal demand using the scaled nodal generation, assuming every circuit has infinite capacity. Then it calculates the resultant total**~~find the shortest~~ network~~ in~~ MWkm**, using the relevant circuit expansion factors as appropriate**~~ which can meet the nodal demand using the scaled nodal generation and assuming every route has infinite capacity~~.

~~2.13~~**2.12** Using this **baseline**~~optimal~~ network **cost**, the model calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (demand) at the reference node, the increase or decrease in total MWkm of the whole network. Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a marginal km cost for generation at each node. The marginal km cost for demand at each node is the equal and opposite to the nodal marginal km for generation. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total **circuit**~~route~~ km.

~~2.14~~**2.13** An example is contained in **Appendix TN-1: Transport Model Example.**

Calculation of zonal marginal km

~~2.15~~**2.14** Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. The definition of the zones was **most recently** reviewed **following**~~during~~ the **2003 Charging Review**~~1996 price control Review~~ **to consider the impact**~~in line with~~**of** the **changes in methodology outlined in paragraph 1.7 above**~~connections terms review~~. Th**is**~~ere~~ **resulted in**~~were~~ 16 generation zones~~ as required by the Director in his October 1996 Price Control proposals, and~~ **The** 12 demand zones relating to the 12 Public Electricity Supply areas **as implemented as part of the October 1996 Price Control proposals remain intact due to practical constraints imposed by metering**.

~~2.16~~**2.15** **Typically, though,** ~~G~~**g**eneration zones **will be**~~are~~ reviewed at the beginning of each price control period.~~ Following the review of zones for April 2001 as part of the October/November 2000 consultation process the number of generation zones was reduced from 16 to 15.~~

~~2.17~~**2.16** The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity. Firstly the zonal marginal km for generation is calculated as:

$$WNMkm_j = \frac{NMkm_j * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi} = \sum_{j \in Gi} WNMkm_j$$

Where

Gi	=	Generation zone
j	=	Node
NMkm	=	Nodal marginal km from transport model
WNMkm	=	Weighted nodal marginal km
ZMkm	=	Zonal Marginal km
Gen	=	Nodal Generation from the transport model

~~2.18~~**2.17** If there is no generation in a particular zone, a simple average of the nodal marginal km is calculated:

$$ZMkm_{G_i} = \frac{\sum_{j \in Gi} NMkm_j}{nj}$$

Where

nj	=	Number of nodes in generation zone Gi

~~2.19~~**2.18** The zonal marginal km for demand zones are calculated as follows:

$$WNMkm_j = \frac{-1 * NMkm_j * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di} = \sum_{j \in Di} WNMkm_j$$

Where

Di	=	Demand zone
Dem	=	Nodal Demand from transport model

~~2.20~~**2.19** A number of criteria are used to determine the definition of the generation zones. The main principles used **since**~~in~~ 1992, **when ICRP charging methodology was introduced,** ~~1996 and 2000~~ in determining the current zonal definition are that:

i.) Zones should contain relevant nodes whose marginal costs (as determined from the output from the transport model and the relevant expansion constant see below) are all within +/-£1/kW (~~1996/97~~**2004/05[?]** prices) across the zone. This means a maximum spread of £2/kW in ~~1996/97~~**2004/05[?]** prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones which contribute to the calculation of the zonal generation tariff.

~~2.21~~**2.20** These criteria are applied to a reasonable range of **DCLF** ICRP transport model scenarios, the inputs to which are determined by National Grid to create appropriate TNUoS generation zones. The minimum number of zones which meet the stated criteria are used. If there is more than one feasible zonal definition of a certain number of zones, National Grid determines and uses the one that best reflects the physical system boundaries.

~~2.22~~**2.21** Zones will **typically** not be reviewed more frequently than once every price review period to provide some stability.

Deriving the Final £/kW Tariff

~~**The Expansion Constant**~~

~~2.23~~**2.22** The zonal marginal km are converted into costs and hence a tariff by multiplying by the **Expansion Constant and the Locational Security Factor (see below)**.

The Expansion Constant

2.23 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport one MW over one km. Its magnitude is derived from the projected cost of 400kV overhead line that National Grid would expect to incur, including an estimate of the cost of capital, if required for future system expansion. Calculated from first principles, the steps taken to derive the expansion constant are as follows:

i.) Each year National Grid determines its projected £/MWkm cost of 400kV overhead line based on actual committed expenditure and latest tenders from manufacturers

ii.) Using the five annual figures taken from the relevant charging year at the beginning of a Price Review and each of the preceding 4 years, a 5 year average figure is calculated

iii.) This average figure sets the Expansion Constant for the first year of the Price Review period and for each subsequent year within the Price Review period, the value is increased by RPI

~~? The Gross Asset Value of the conductors and towers embodying National Grid's overhead lines, excluding those attributed and charged as connection assets is summatedA similar summation is done for cable infrastructure assets~~

~~? These totals are divided by the total MWkm of overhead line and cable respectively~~

- ~~A substation element per MWkm is included on the basis of the current average of National Grid infrastructure substation assets~~
- Allowances for engineering and interest costs are added
- The capital cost figures are converted into annuities
- An addition is made for the cost of maintenance.

2.24 As an illustration the expansion constant **calculated**~~used~~ for 200~~2~~**3**/0~~3~~**4** was £~~27~~**9**.~~75~~**29**/MWkm.

The Locational Security Factor

2.25 The locational security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak demand is able to met despite N-1 and N-2 contingencies on the network. Essentially the calculation of nodal marginal costs is identical to the process outlined above except that the secure DCLF study increases line capacity where appropriate to ensure intact load flows under the network contingencies.

2.26 The maximum nodal cost diffferential is compared to that produced by the DCLF ICRP transport model and the resultant ration of the two determines the locational security factor

2.27 As an illustration, the locational security factor derived for 2003/04 was 1.9

Initial Transport Tariff

~~2.25~~**2.28** First an Initial Transport Tariff (ITT) must be calculated. For Generation the zonal marginal km (ZMkm) are simply multiplied by the expansion constant to give the initial transport tariff:

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

Where

$ZMkm_{Gi}$	=	Zonal Marginal km for each generation zone
EC	=	Expansion Constant
LSF	**=**	**Locational Security Factor**
ITT_{Gi}	=	Initial Transport Tariff (£/MW) for each generation zone

~~2.26~~**2.29** Similarly, for demand the zonal marginal km (ZMkm) are simply multiplied by the expansion constant to give the initial transport tariff:

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

Where

$ZMkm_{Di}$	=	Zonal Marginal km for each demand zone
EC	=	Expansion Constant
LSF	**=**	**Locational Security Factor**
ITT_{Di}	=	Initial Transport Tariff (£/MW) for each demand zone

~~2.27~~**2.30** The next step is to multiply these initial transport tariffs by the expected metered triad demand and actual generation capacity to gain an estimate of the initial revenue recovery. As noted above both of these latter parameters are based on forecasts provided by Users and are confidential.

$$\sum_{Gi=1}^{15}\left(ITT_{Gi} \times G_{Gi}\right) = ITRR_G \quad \text{and} \quad \sum_{Di=1}^{12}\left(ITT_{Di} \times D_{Di}\right) = ITRR_D$$

Where

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

~~2.28~~**2.31** The next stage is to correct the Initial Transport Revenue Recovery figures above such that the 'correct' split of revenue between generation and demand is obtained~~. This, as discussed in the principles outlined above, was determined by the~~

~~Director in his 1996 Price Control proposals to be approximately 27:73 for generation and demand respectively~~. In order to achieve the 'correct' generation/demand revenue split, a single additive constant C is calculated which is then added to all the zonal marginal km, both for generation and demand as below:

$$\sum_{Gi=1}^{15}\left[\left(ZMkm_{Gi}+C\right)\times EC\times LSF\times G_{Gi}\right]=CTRR_G$$

$$\sum_{Di=1}^{12}\left[\left(ZMkm_{Di}-C\right)\times EC\times LSF\times D_{Di}\right]=CTRR_D$$

Where C is set such that

$$CTRR_D = p\left(CTRR_G + CTRR_D\right)$$

Where

CTRR	=	"Generation / Demand split" corrected transport revenue recovery
p	=	Proportion of revenue to be recovered from demand
C	=	"Generation /Demand split" Correction constant (in km)

~~2.29~~**2.32** The above equations deliver corrected (£/MW) transport tariffs (CTT).

$$\left(ZMkm_{Gi}+C\right)\times EC\times LSF = CTT_{Gi}$$

$$\left(ZMkm_{Di}-C\right)\times EC\times LSF = CTT_{Di}$$

So that

$$\sum_{Gi=1}^{15}\left(CTT_{Gi}\times G_{Gi}\right)=CTRR_G \quad \text{and} \quad \sum_{Di=1}^{12}\left(CTT_{Di}\times D_{Di}\right)=CTRR_D$$

The ~~Security &~~ Residual Tariff

~~2.30~~**2.33** The total revenue to be recovered through TNUoS charges is determined each year with reference to National Grid's TO Price Control formula less the costs expected to be recovered through Pre-Vesting connection charges. **Only 90% of this is recovered via peak TNUoS tariffs, the remaining 10% being recovered via year round commodity (£/MWh) TNUoS tariffs, as outlined in Chapter 4.** Hence in any given year t, a target revenue figure for **peak** TNUoS charges (**P**TRR$_t$) is set as follows:

$$PTRR_t = (P_t - PVC_t)\times 90\%$$

Where

PTRR$_t$ = **Peak** TNUoS Revenue Recovery target for year t

P_t = Revenue allowed under National Grid's RPI-X Price Control Formula for year t. (i.e. including any adjustment for over/under recovery from the previous year K_t)

PVC_t = Revenue recovered from Pre-Vesting connection charges for year t

~~2.32~~In normal circumstances, the revenue forecast to be recovered from the corrected transport tariffs will not equate to the total **peak** revenue target. This is due to a number of factors. F**or example**~~irstly, the transport model does not take account of the wider requirements in the use of system service such as the need to provide secure transport with a stable frequency and voltage. This is governed by the Security Standards which are referred to in the transmission licence. The standard refers primarily to conditions at time of peak on the system, principally because this is seen as the most onerous condition in terms of the overall security of the electricity supply system. For example, this time is when there is deemed to be the greatest risk of insufficient generating plant available to meet demand. The consequence of the application of the Security Standard is that additional transmission capacity is required over and above that required for the simple transport of energy.In addition~~, 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.

~~2.33~~**2.34** As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational ~~**Security and**~~ **Residual Tariff** for generation and demand is calculated. It is added to the corrected transport tariffs so that the correct generation/ demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{(p \times PTRR) - CTRR_D}{\sum_{Di=1}^{12} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times PTRR] - CTRR_G}{\sum_{Gi=1}^{15} G_{Gi}}$$

Where

~~S~~RT	=	~~Security and~~ Residual Tariff (£/MW)
p	=	Proportion of revenue to be recovered from demand

Final £/kW Tariff

~~2.34~~**2.35** The final Transmission Network Use of System tariff (TNUoS) can now be calculated as the sum of the corrected transport tariff and the non-locational security and residual tariff:

$$FT_{Gi} = \frac{CTT_{Gi} + RT_G}{1000} \quad \text{and} \quad FT_{Di} = \frac{CTT_{Di} + RT_D}{1000}$$

Where

FT = Final TNUoS Tariff expressed in £/kW

~~2.35~~**2.36** An example of the final zonal tariff table and zonal maps is shown below. The tariffs applicable for any particular year are detailed in National Grid's **Statement of Use of System Charges,** which is available from our **Charging Team.** Historical tariffs are available on the **Charging website.**

~~2.36~~**2.37** The zonal maps referenced in National Grid'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.

~~2.37~~**2.38** 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.

~~2.38~~**2.39** National Grid has available, upon request, the **DCLF** ICRP transport model and data necessary to run the model, consisting of nodal values of generation and demand for National Grid connection points. 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 via the **Charging Website**.

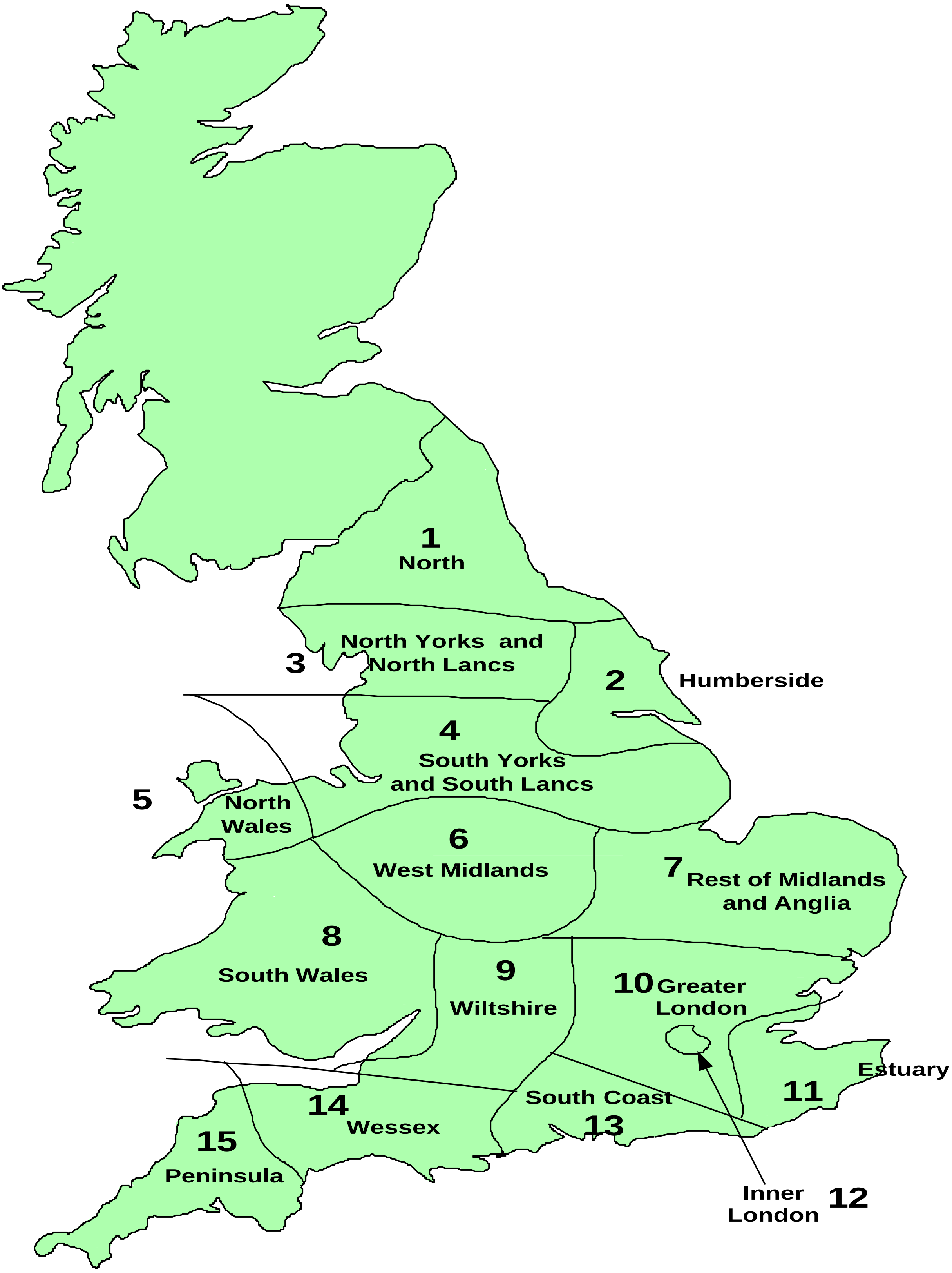
~~2.39~~**2.40** National Grid will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

~~2.40~~The factors which will affect the level of Transmission Network Use of System 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,** changes in the transmission network and changes in the pattern of generation capacity and demand.

Example of the Schedule of Charges for Transmission Network Use of System (£/kW) in XXXX/YYYY as published in the Statement of Use of System Charges [would need to be changed in line with any implementation of revised zones]

Generation Zone	Zone Area	Generation Tariff (£/kW)	Demand Zone	Zone area	Demand Tariff (£/kW)
1	North		1	Northern	
2	Humberside		2	North West	
3	N Yorks & N Lancs		3	Yorkshire	
4	S Yorks & S Lancs		4	North Wales and Mersey	
5	North Wales		5	East Midlands	
6	West Midlands		6	Midlands	
7	Rest of Midlands and Anglia		7	Eastern	
8	SouthWales		8	South Wales	
9	Wiltshire		9	South East	
10	Greater London		10	London	
11	Estuary		11	Southern	
12	Inner London		12	South Western	
13	South Coast				
14	Wessex				
15	Peninsula				

Example of TNUoS Generation Zones [would need to be changed in line with any implementation of revised zones]



Example of TNUoS Demand Zones

Appendix 4 – Proposed Change to Chapter 3: Derivation of the Transmission Use of Network System Energy Consumption Tariff

Chapter 3: Derivation of the Transmission Network Use of System Peak Energy Consumption Tariff

3.1 For the purposes of this section Trading Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

3.2 Following calculation of the Transmission Network Use of System £/kW Demand Tariff (as outlined in **Appendix 3: Proposed Changes to Chapter Derivation of Transmission Network Use of System Tariff**

3.3

~~3.~~4Chapter 2: Derivation of the Peak Transmission Network Use of System Tariff~~Appendix 3: Proposed Changes to Chapter Derivation of Transmission Network Use of System Tariff~~

~~3.3~~

~~3.4Chapter 2: Derivation of the Peak Transmission Network Use of System TariffAppendix 3: Proposed Changes to Chapter Derivation of Transmission Network Use of System Tariff~~

~~3.3~~

3.4 **~~Chapter 2: Derivation of the Transmission Network Use of System~~** ~~Tariff~~) the p/kWh **peak** energy consumption tariff for each GSP Group is calculated as follows:

$$\textbf{p/kWh Tariff} = \frac{(\textbf{NHHDF} * \textbf{£/kW Tariff})}{\textbf{NHHC}_G} \textbf{*100}$$

Where:

£/kW Tariff = The £/kW Demand Tariff (£/kW), as shown in Schedule 1 of **The Statement of Use of System Charges,** for the GSP Group concerned.

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

$NHHC_G$ = National Grid'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 for the year 1 April to 31 March for the GSP Group concerned.

3.5 An example of the final zonal tariff table is shown below. The tariffs applicable for any particular year are detailed in National Grid's **Statement of Use of System Charges** which is available from our **Charging Team.** Historical tariffs are available on the **Charging website.**

Example of the Schedule of Charges for Transmission Network Use of System Energy Consumption Charges (p/kWh) for XXXX/YYYY as published in the Statement of Use of System Charges

Demand Zone	Zone area	Energy Consumption Tariff (p/kWh)
1	Northern	
2	North West	
3	Yorkshire	
4	North Wales and Mersey	
5	East Midlands	
6	Midlands	
7	Eastern	
8	South Wales	
9	South East	
10	London	
11	Southern	
12	South Western	

Appendix 5 – Proposed New Chapter 4: Derivation of the Year Round TNUoS Tariffs for Generation and Demand

Chapter 4: Derivation of the Year Round Commodity TNUoS Tariffs for Generation and Demand

4.1 **The Year Round Energy TNUoS tariffs for generation and demand are levied to recover 10% of National Grid's allowed total TNUoS revenue recovery. It is charged as two flat p/MWh tariffs for generation and demand respectively to ensure recovery of the revenue in the appropriate G:D split. These tariffs are applied to the metered output for generation and metered demand for suppliers.**

4.2 The Year Round Energy TNUos Tariffs are derived as follows;

$$YRT_D = \frac{(P_t - PVC_t) \times 10\% \times DRP_t}{FADE_t}$$

$$YRT_G = \frac{(P_t - PVC_t) \times 10\% \times GRP_t}{FAGO_t}$$

Where

YRT_D	**=**	**Year Round Demand Tariff (p/MWh)**
DRP_t	**=**	**Demand Recovery Percentage for relevant charging year t**
$FADE_t$	**=**	**Forecast Annual Demand Energy (MWh)**
YRT_G	**=**	**Year Round Generation Tariff (p/MWh)**
GRP_t	**=**	**Generation Recovery Percentage for relevant charging year t**
$FAGO_t$	**=**	**Forecast Annual Generation Output (MWh)**

4.3 An example of typical levels of Year Round Energy TNUoS tariffs would be 6p/MWh and 18p/MWh for generation and demand respectively.

Appendix 5: Proposed Change to Chapter 4: Demand Charges

Chapter ~~4~~5: Demand Charges

Parties Liable for Demand Charges

~~4.1~~**5.1** The following parties shall be liable for demand charges:

- The Lead Party of a Supplier BM Unit;
- The Lead Party of a BM Unit associated with a Licensable Power Station;
- The Lead Party of an Exempt Export BM Unit;
- An Interconnector Asset Owner.

~~4.2~~**5.2** **Appendix TN-5: 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 paragraphs most pertinent to each party.

Basis of Demand Charges

~~4.3~~**5.3** The values of Triad demand (kW)**,** ~~and~~ **peak** energy consumption (kWh) **and year round energy (MWh)** to be multiplied by the relevant demand**,** ~~or~~ **peak** energy consumption **or year round energy** tariff, for the calculation of demand charges, are set out below.

Supplier BM Unit

~~4.4~~**5.4** The demand charges for a Supplier BM Unit will be based on:

- The average of the Supplier BM Unit's half-hourly metered demand during the Triad (and the kW tariff), *and*
- 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 **peak energy** kWh tariff)
- **The Supplier BM Unit's total half hourly metered energy consumption over the Financial Year (and the year round energy MWh tariff)**

Licensable Power Station

~~4.5~~**5.5** The demand charges for a Licensable Power Station will be based on**:**

- **the average of the net metered import of the Power Station (including metered additional load) during the Triad,** ***and***
- **the total half hourly metered import of the Power Station over the Financial Year (and the year round energy MWh tariff)**

Exempt Export BM Unit & Derogated Distribution Interconnector BM Unit

~~4.6~~5.6 The demand charges for an Exempt Export BM Unit or Derogated Distribution Interconnector BM Unit will be based on**:**

- **the average of the metered volume of the Exempt Export BM Unit or Derogated Distribution Interconnector BM Unit during the Triad (and the peak kW tariff),** ***and***

- **the total half hourly metered volume of the Exempt Export BM Unit or Derogated Distribution Interconnector BM Unit over the Financial Year (and the year round energy MWh tariff)**

Directly Connected Interconnectors and those capable of exporting more than 100MW to the Total System

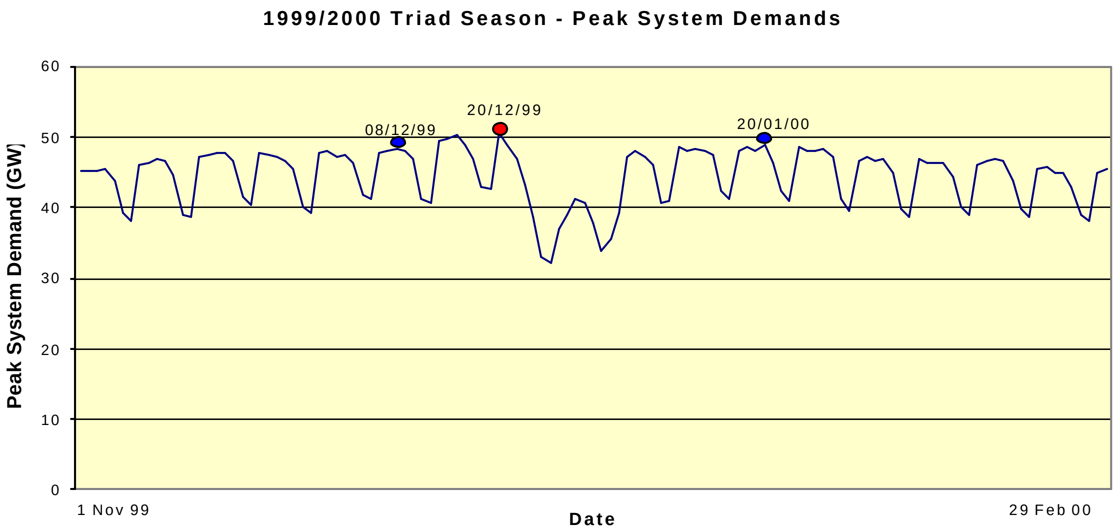
~~4.7~~5.7 The basis of the demand charges for these Interconnectors will be**:**

- **the average net metered import of the Interconnector during the Triad (including Interconnector errors with the exception of Emergency Assistance actions).**

- **the total half hourly metered volume of the Interconnector over the Financial Year (and the year round energy MWh tariff)**

The Triad

~~4.8~~5.8 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand of a Financial Year, namely the half hour settlement period of system peak demand and the two half hour settlement periods of next highest demand, which are separated from the system peak demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. An illustration is shown below.



Half-hourly metered demand charges

5.9 ~~4.9~~ For Supplier BMUs, Exempt Export BMUs and Derogated Distribution Interconnector BMUs, if the average half-hourly metered volume over the Triad results in an import, the BMU will be charged the amount of the relevant kW tariff multiplied by the average import. If the average half-hourly metered volume over the Triad results in an export, the BMU will be paid the amount of the relevant kW tariff multiplied by the average export. For the avoidance of doubt, Exempt Export BMUs and Derogated Distribution Interconnector BMUs liable for Generation charges will not be liable for negative demand charges.

Netting off within a BM Unit

~~4.10~~**5.10** The output of generators and Distribution Interconnectors~~ not registered in CVA, but~~ registered~~ in SVA~~ as part of a Supplier BM Unit, will have already been accounted for in the Supplier BM Unit demand figures upon which National Grid Transmission Network Use of System Demand charges are based.

Monthly Charges

~~4.11~~**5.11** Throughout the year Users' monthly demand charges will **firstly** be based on their forecasts of:

- half-hourly metered demand 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

These charges 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. National Grid 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 an import from the system) will be accepted.

User's will also see a monthly charge for month M-2 based on their outturn metered energy, multiplied by the year round energy p/MWh tariff for demand. This lag is due to the need to use daily Settlement Final (SF) data from Elexon. This data is issued 28 days in arrears, hence SF data for 30 April becomes available on 28 May. Thus to fit with National Grid's charging process the year round charge applicable for the month of April would be invoiced to the user on 1 June i.e. 2 months in arrears.

5.12 For year round charges, due to tight timescales between receipt of outturn metered data and invoicing, a default process will be adopted for situations where there is any problem in obtaining relevant data due to, for example, system outages. Specifically, it data is not available, at time of invoicing, for a relevant business day, the data available from the same day of the preceding week will be used. If this is not available the data for the same day two weeks previously will be used etc. For a non-business day, if data iss not available for a relevant day, at time of invoicing, the data from the most recent previous non-business day will be used.

Reconciliation of Demand Charges

~~4.12~~**5.13** 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 (following the implementation of the 1998 Trading Arrangements), reconciliation of **peak** demand charges is carried out in two stages; initial reconciliation and final reconciliation. **Year round demand charges only require a final reconciliation since the initial charge to users is based on outturn SF data.**

Initial Reconciliation of peak demand charges

~~4.13~~**5.14** **For peak related demand charges,** ~~T~~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; Part 1 deals with the reconciliation of half-hourly metered demand charges and Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

Initial Reconciliation of Peak Charges Part 1– Half-hourly metered demand

~~4.14~~**5.15** National Grid 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 National Grid 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.

~~4.15~~**5.16** Initial outturn charges for half-hourly metered demand will be determined using the latest available data of actual average Triad demand (kW) multiplied by the zonal demand tariff (£/kW) for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly demand.

Initial Reconciliation of Peak Charges Part 2–– Non-half-hourly metered demand

~~4.16~~**5.17** Actual payments for non-half-hourly metered demand for **peak energy consumption** 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 **peak** energy consumption tariff (p/kWh) for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly **peak** energy consumption.

Final Reconciliation of demand charges

~~4.17~~**5.18** The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data **for peak demand charges and as initially applied for year round demand charges**) against final outturn demand charges (based on final settlement data).

~~4.18~~**5.19** 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.

Further Information

~~4.19~~**5.20** **Appendix TN-4: Reconciliation of Demand Related Transmission Network Use of System Charges** of this statement illustrates how the monthly charges are reconciled against the actual values for demand and consumption for half-hourly and non-half-hourly metered demand respectively.

~~4.20~~**5.21** **The Statement of Use of System Charges** contains the **peak** £/kW **zonal** demand tariff**s,** ~~and~~ the p/kWh **peak** energy consumption tariff**s and the year round p/MWh energy tariff** for the current Financial Year.

~~4.21~~**5.22** **Appendix TN-6: Transmission Network Use of System Charging Flowcharts** of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

Appendix 6 - Proposed Change to Chapter 5: Generation Charges

Chapter ~~5~~6: Generation charges

Parties Liable for Generation Charges

~~5.1~~6.1 The following parties shall be liable for generation charges:

i) The Lead Parties of BM Units comprising Licensable Generation which form the whole or part of a Power Station or Trading Unit that is capable of exporting 100MW or more to the Total System, as agreed with National Grid.

ii) The Lead Parties of BM Units comprising generation that have a Bilateral Connection Agreement with National Grid.

iii) Interconnector Asset Owners of Interconnectors capable of exporting 100MW or more to the Total System.

~~5.2~~6.2 **Appendix TN-5: 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.

Basis of **Peak** Generation Charges

~~5.3~~6.3 The value of generation to be multiplied by the relevant generation tariff, for the calculation of **peak** generation charges, is set out below. For the avoidance of doubt, the intention of the charging rules is to charge the same physical entity only once.

~~5.4~~6.4 The basis of the **peak** generation charge for Power Stations and Interconnectors is the Chargeable Capacity (as defined below for positive and negative charging zones).

Positive Charging Zones

~~5.5~~6.5 The Chargeable Capacity for Power Stations situated in positive charging zones is the highest Transmission Entry Capacity (TEC) applicable to that Power Station for that Financial Year.

~~5.6~~6.6 The Chargeable Capacity for an Interconnector connected to a positive charging zone is the highest TEC applicable to that Interconnector for that Financial Year.

Negative Charging Zones

~~5.7~~6.7 The Chargeable Capacity for Power Stations and Interconnectors situated in negative charging zones is the average of the capped metered volumes during the three settlement periods described in 5.8 below, for the Power Station (i.e. the sum of the metered volume of each BM Unit associated with Power Station) or Interconnector. The metered volumes are each capped by the TEC for the Power Station or Interconnector applicable for that Financial Year.

~~5.8~~6.8 The three settlement periods are those of the highest metered volumes for the Power Station or Interconnector 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 to not have to coincide with the Triad.

Example

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

Date	19/11/02	13/12/02	6/2/03
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:

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

Basis of Year Round Generation Charges

6.9 All parties liable for generation charges as outlined above will also pay the year round energy TNUoS tariff for generation. This will be applied to actual metered output of relevant generators

Monthly Charges

~~5.9~~**6.10** Initial Transmission Network Use of System Generation Charges will be based on the **Station** Transmission Entry Capacity for each User as set out in their Bilateral Agreement **and their monthly metered output for month M-2**. The **peak** charge is calculated taking the forecast Chargeable Capacity and multiplying it by the zonal £/kW tariff.~~ ~~**For positive charging zones if TEC increases during the charging year, the additional annual charge incurred will be recovered uniformly across the remaining chargeable months in the relevant charging year. For negative charging zones, any change in TEC during the year will lead to a recalculation of the monthly charges for the remaining chargeable months of the relevant charging year. If TEC increases, monthly payments to the generator will increase accordingly, and if TEC decreases, monthly payments will fall accordingly.**

~~5.9~~**6.11 The year round charge is calculated taking the monthly metered output and multiplying it by the year round p/MWh energy tariff for generation. However, the charges is applied with a 2 month lag due to the need to use daily Settlement Final (SF) data from Elexon. This data is issued 28 days in arrears, hence SF data for 30 April becomes available on 28 May. Thus to fit with National Grid's charging process the year round charge applicable for the month of April would be invoiced to the user on 1 June i.e. 2 months in arrears.**

6.12 The~~is~~ **total charge is derived from the aggregation of (a) peak charges** ~~is~~ **split evenly over the 12 months and charged on a monthly basis over the year with (b) the monthly charges applied for year round charges in month M-2. Specifically, the generator will see a charge in June equating to 1/12 of its annual peak charge plus the relevant year round charge for April.**

6.13 For year round charges, due to tight timescales between receipt of outturn metered data and invoicing, a default process will be adopted for situations where there is any problem in obtaining relevant data due to, for example, system outages. Specifically, it data is not available, at time of invoicing, for a relevant business day, the data available from the same day of the preceding week will be used. If this is not available the data for the same day two weeks previously will be used etc. For a non-business day, if data iss not available for a relevant day, at time of invoicing, the data from the most recent previous non-business day will be used.

Reconciliation of Generation Charges

~~5.10~~**6.14** The reconciliation process is set out in the CUSC. Final Generation Charges will be based upon the highest actual Transmission Entry Capacity **and the actual annual metered output** applicable to that User for the Financial Year being reconciled. **Due to the nature of year round charges Final Reconciliation takes place in June of Year N+1, consistent with that for demand charges.**

Further Information

~~5.11~~**6.12** **The Statement of Use of System Charges** contains the £/kW **peak** generation **zonal** tariff**s and the p/MWh year round generation tariff** for the current Financial Year.

Appendix 7 – Proposed Changes to Chapter 6: Data Requirements

Chapter ~~6~~7: Data Requirements

Data Required for Charge Setting

~~6.1~~**7.1** Users who are Generators or Interconnector Asset Owners shall provide to National Grid 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. This data is required by National Grid as the basis for setting **peak** TNUoS tariffs. National Grid will request these forecasts in the November prior to the Financial Year to which they relate, in accordance with the CUSC.

~~6.2~~**7.2** 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.

~~6.3~~**7.3** For the following Financial Year, National Grid shall use these forecasts as the basis of **peak** Transmission Network Use of System charges for such Financial Year. A description of how this data is incorporated is included in **Appendix 3: Proposed Changes to Chapter Derivation of Transmission Network Use of System Tariff**

~~6.3~~**7.4**

~~6.3~~**Chapter 2: Derivation of the Peak Transmission Network Use of System Tariff**~~**Appendix 3: Proposed Changes to Chapter Derivation of Transmission Network Use of System Tariff**~~

~~6.3~~

~~**6.3Chapter 2: Derivation of the Peak Transmission Network Use of System TariffAppendix 3: Proposed Changes to Chapter Derivation of Transmission Network Use of System Tariff**~~

~~6.3~~

~~6.3~~**7.5** ~~Chapter **2: Derivation of the Transmission Network Use of** System Tariff~~**.**

~~6.4~~**7.6** If no data is received from the User, then National Grid 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

~~6.5~~**7.7** In order for National Grid to calculate Users' **peak** TNUoS charges, Users who are Suppliers shall provide to National Grid forecasts of half-hourly and non-half-hourly demand in accordance with paragraph 4.11.

Appendix 8 - Proposed Changes to Chapter 7: Applications

Chapter ~~7~~8: Applications

~~7.1~~**8.1** Application fees are payable in respect of applications for new use of system agreements and modifications to existing agreements based on the reasonable costs National Grid incurs in processing these applications. Users can opt to pay a fixed price application fee (derived from analysis of the historical costs of similar applications) 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**.

~~7.2~~**8.2** If a User chooses not to pay the fixed fee, an application fee will be designed as an advance of National Grid Engineering and out-of pocket expenses and will vary according to the size of the scheme and the amount of work involved. Where actual expenses exceed the advance, National Grid will issue an invoice for the excess. Conversely, where National Grid does not use the whole of the advance, the balance will be refunded.

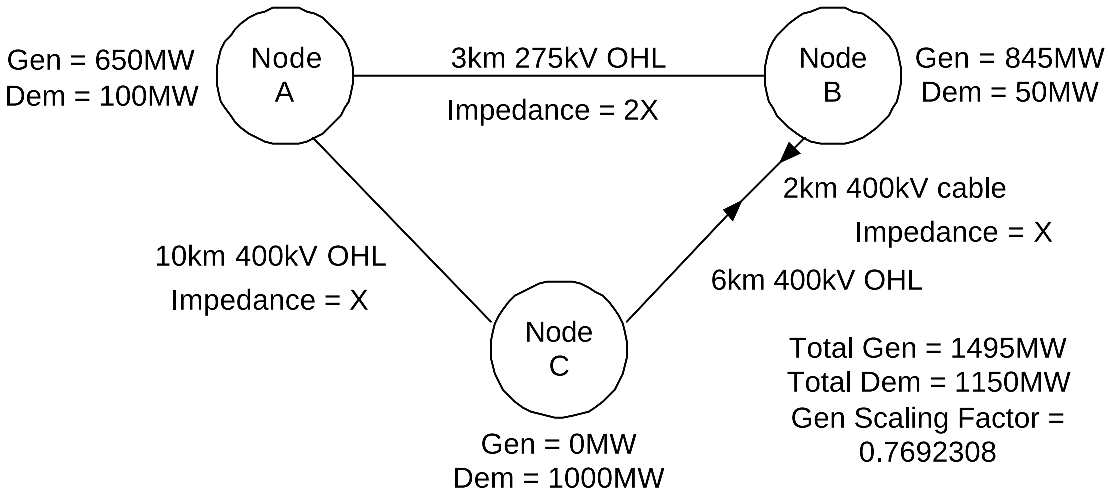
~~7.3~~**8.3** National Grid will refund application fees and consent payments made under the Construction Agreement either on commissioning or against the charges payable in the first three years of the new or modified agreement. The following conditions apply:

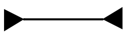
- The refund will be net of external costs;
- Where a new or modified agreement is signed and subsequently modified at the User's request before any charges become payable, National Grid will refund the original application fee. National Grid will not refund the fees in respect of the subsequent modification(s).

Appendix 9 – Proposed Changes to Appendix TN-1: Transport Model Example

Appendix TN-1: Transport Model Example

Consider the following 3 node network:

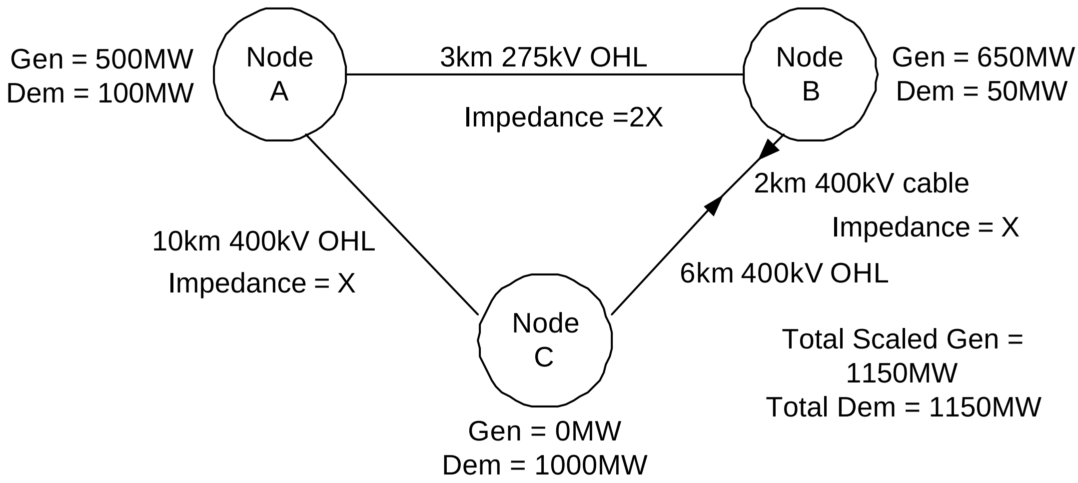



Denotes cable

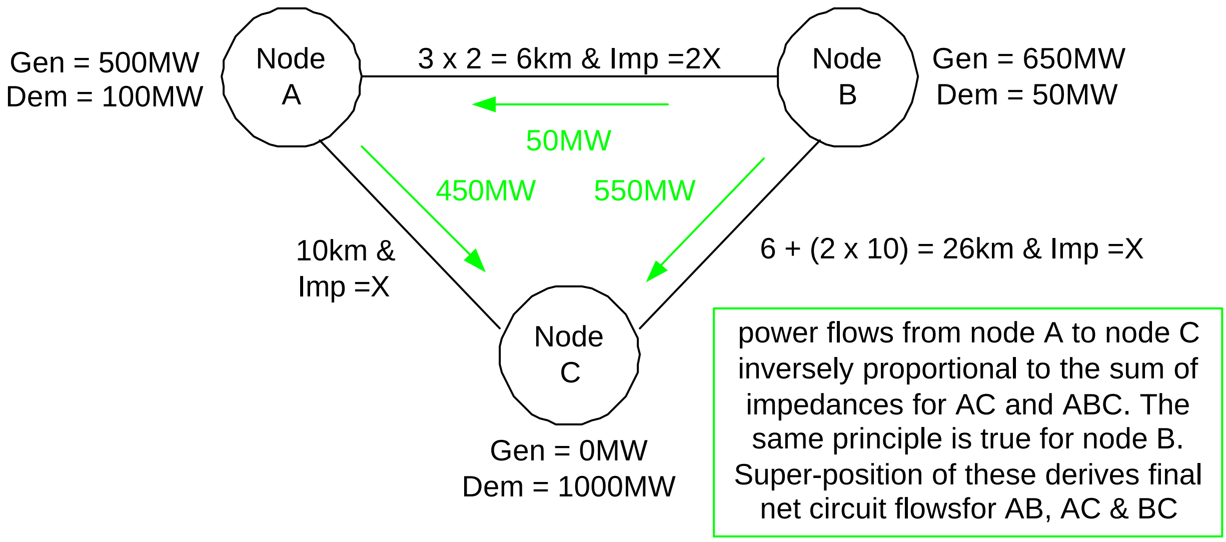
The first step is to match total demand and total generation by scaling uniformly the nodal generation down such that total system generation equals total system demand.

Node A Generation = 1150/1495 * 650MW = 500MW
Node B Generation = 1150/1495 * 845MW = 650MW

This gives the following balanced system:



Assuming Node A is the reference node**, each circuit has impedance X** ~~and~~ the **400kV** cable **circuit expansion** factor is 10 **and the 275kV overhead line circuit expansion factor is 2**, the **DCLF transport algorithm** ~~linear optimisation program reduces the network and~~ calculates the base case power flows ~~(to the minimum MWkm cost)~~ as follows:



Nodes A & 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 400MW; route AC has impedance X and route ABC has impedance 3X; hence 300MW would flow down AC and 100MW along ABC**

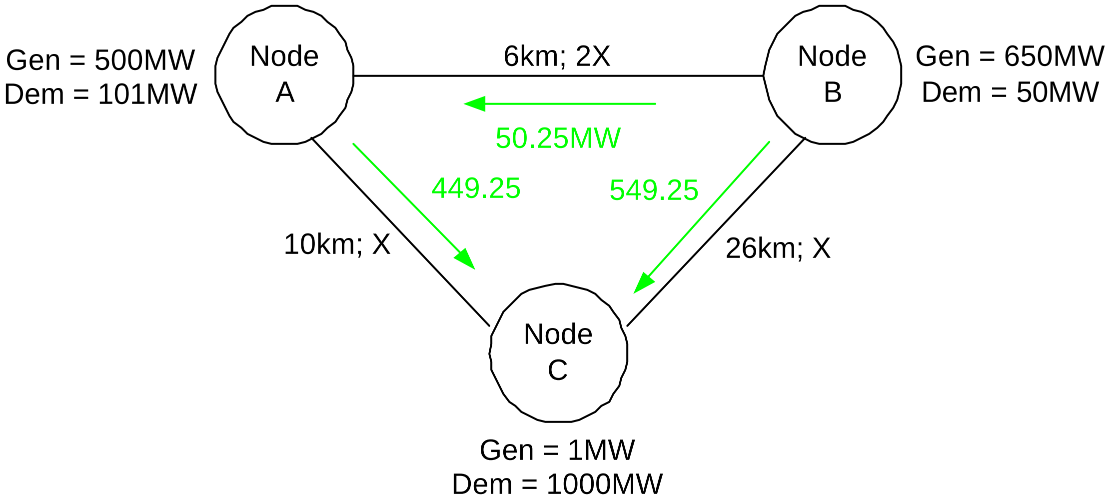
Step 2: **Net export from Node B is 600MW; route BC has impedance X and route BAC has impedance 3X; hence 450MW would flow down BC and 150MW along BAC**

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

FlowAC	**= 300MW + 150MW**	**=**	**450MW**
Flow AB	**= 100MW – 150MW**	**=**	**-50MW**
Flow BC	**= 100MW + 450MW**	**=**	**550MW**

Total cost = (~~600~~**450** x ~~3~~**10**) + (~~1,000~~**50** x ~~10~~**6**) **+ (550 x 26)** = 19~~1~~,~~8~~100 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 MWkm cost. The difference in cost from the base case is the marginal km or shadow cost. This is demonstrated as follows:



To calculate the marginal km at node C:

Total Cost = (**449.25**~~600~~ x ~~3~~**10**) + (**50.25**~~999~~ x ~~10~~**6**) **+ (549.25 x 26)** = 1**9**~~1~~,~~790~~**074.5** MWkm

Thus the overall cost has reduced by ~~10~~ **25.5** (i.e. the marginal km = -**25.5**~~10~~).

Appendix 10 – Proposed Changes to Appendix TN-2: Example: Calculation of Zonal Generation Tariff

Appendix TN-2: Example: Calculation of Zonal Generation Tariff

Let us consider all nodes in generation zone ~~7~~**8**: ~~Rest of Mids &~~ **East** Anglia.

The table below shows a sample output of the transport model comprising the node, the marginal km of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand and the demand sited at the node.

Genzone	Node	Nodal Marginal km	Scaled Generation
8	**BRAI4A**	**105.37**	**0**
~~7~~**8**	BRFO**40**	~~51.8~~**118.89**	0
~~7~~**8**	BURW**40**	~~23.7~~**110.86**	0
~~7~~**8**	EASO**40**	~~40.02~~**112.99**	~~523.07~~**0**
8	**ECLA40_AQUL**	**-6.49**	**0**
8	**ECLA40_EME**	**-6.49**	**0**
~~7~~**8**	GREN**40**_EM**E**	~~10.82~~**79.56**	~~312.3~~**321.38**
~~7~~**8**	GREN**40-**E**P**N	~~10.82~~**79.56**	0
~~7~~	~~KINL~~	~~78~~	~~292.3~~
8	**LEIB4A**	**19.03**	**0**
8	**LEIB4B**	**13.95**	**0**
8	**LITB40**	**180.20**	**551.73**
~~7~~**8**	NORW**40**	~~10.9~~**108.96**	~~315.38~~**332.46**
8	**PAFB4A**	**38.66**	**0**
8	**PAFB4B**	**38.67**	**0**
8	**PELH40**	**76.97**	**0**
~~7~~**8**	SIZE**40**	~~57.21~~**157.43**	~~1269.2~~**1337.77**
~~7~~**8**	SP**LN40**~~AL~~	~~84.32~~**186.18**	0
8	**SUND40**	**35.14**	**0**
~~7~~**8**	WALP**40**_EM**E**	~~62.1~~**164.24**	~~616.14~~**0**
~~7~~**8**	WALP**40**_E**P**N	~~62.1~~**164.24**	~~311.53~~**1257.03**
8	**WYMO40**	**74.74**	**0**
		Totals	~~3639.92~~**3800.38**

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

(i) calculate the generation weighted nodal shadow costs.

For zone ~~7~~**8** this would be as follows:

Genzone	Node	Nodal Marginal km	Scaled Generation (MW)	Gen Weighted Nodal Marginal km
~~7~~	~~EASO~~	~~40.02~~	~~523.07~~	~~5.75~~
~~7~~**8**	GREN**40**_EM**E**	~~10.82~~**79.56**	~~312.3~~**321.38**	~~0.93~~**6.73**

~~7~~**8**	~~KINL~~**LITB40**	~~78~~**180.20**	~~292.3~~**551.73**	~~6.26~~**26.16**
~~7~~**8**	NORW**40**	~~10.9~~**108.96**	~~315.38~~**332.46**	~~0.94~~**9.53**
~~7~~**8**	SIZE**40**	~~57.2~~**157.43**	~~1269.2~~**1337.77**	~~19.95~~**55.42**
~~7~~	~~WALPEM~~	~~62.1~~	~~616.14~~	~~10.51~~
~~7~~**8**	WALP**40**_E**P**N	~~62.1~~**164.24**	~~311.53~~**1257.03**	~~5.31~~**54.32**
		Totals	~~3639.92~~**3800.38**	

i.e. $\dfrac{\cancel{62.1}\,\mathbf{164.24} \times \cancel{616.14}\,\mathbf{1257.03}}{\cancel{3639.92}\,\mathbf{3800.38}}$

(ii) sum the generation weighted nodal shadow cost to give a zonal figure.

For zone ~~7~~**8** this would be:

(~~5.75 + 0.93 + 6.26 + 0.94 + 19.95 + 10.51 + 5.31~~**16.73 + 26.16 + 49.53 + 55.42 + 54.32**) km = ~~49.65~~ **152.16km**

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the ~~27:73~~**28:72** (approx) split of revenue recovery between generation and demand is retained.

For zone ~~7~~**8** this would be **say**:

~~49.65~~**152.16**km + (-~~64.08~~**127.41**km) = ~~-14.43~~**24.75 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

(iv) calculate the transport tariff by multiplying the figure in (iii) above by the expansion constant (& dividing by 1000 to put into units of £/kW).

For zone 7 and assuming an expansion constant of £**9.29**~~27.03~~/MWkm **and a locational security factor of 1.9**:

$$\frac{\cancel{-14.43}\,\mathbf{24.75}\text{km} * \pounds\cancel{27.03}\,\mathbf{9.29}/\text{MWkm} \mathbf{\ * 1.9}}{1000} = \cancel{-}\pounds\mathbf{0.}\cancel{39}\mathbf{44}/\text{kW}$$

(v) We now need to calculate the~~ security &~~ residual tariff. This is calculated by taking the total revenue to be recovered from generation (calculated as c.2**8**~~7~~% of total National Grid TNUoS target revenue for the year) less the revenue which would be recovered through the generation transport tariffs divided by total expected generation.

Assuming the total revenue to be recovered from TNUoS is £650m, the total recovery from generation would be (2~~7~~**8**% x £~~650~~**785**m) = £~~175.5~~**219.8**m.

Assuming the total recovery from generation transport tariffs is £~~50~~**45**m and total forecast chargeable generation capacity is 62000MW, the Generation~~ security &~~ residual tariff would be as follows:

$$\frac{£219.8m - £45m}{62000MW} = \underline{£2.82/kW}$$

(vi) to get to the final tariff, we simply add on the generation~~ security &~~ residual tariff calculated in (v) to the zonal transport tariff calculated in (iv).

For zone ~~7~~**8**:

-£**0.44**~~0.39~~/kW + £2.~~02~~**82**/kW = **£~~1.63~~3.24/kW**

To summarise, in order to calculate the generation tariffs, we evaluate a generation weighted zonal marginal km cost, modify by a re-referencing quantity to ensure that our revenue recovery split between generation and demand is correct, then we add a constant (termed the security + residual cost) to give the overall tariff.

Appendix 11 – Proposed Changes to Appendix TN-3: Example: Calculation of Zonal Demand Tariff

Appendix TN-3: Example: Calculation of Zonal Demand Tariff

Let us consider all nodes in demand zone 12: South Western.

The table below shows a sample output of the transport model comprising the node, the marginal km of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation = total national demand and the demand sited at the node.

Demand Zone	Node	Nodal Marginal km	Demand (MW)
12	ABHA**4A**	~~-320.7~~ **-412.07**	~~267~~**137**
12	**ABHA4B**	**-412.45**	**137**
12	ALVE**4A**	~~-318.7~~ **-362.07**	~~179~~**112**
12	**ALVE4B**	**-373.75**	**112**
12	AXMI**40**_SW**EB**	~~-282.3~~ **-368.40**	~~100~~**107**
12	BRWA**2A**	~~-248.2~~ **-340.96**	~~181~~**96.5**
12	**BRWA2B**	**-341.09**	**96.5**
12	EXET**40**	~~-284~~ **-355.14**	~~317~~**320**
12	HINP**20**	~~-219.1~~ **-289.76**	26
12	**HINP40**	**-289.76**	**0**
12	INDQ**40**	~~-391.9~~ **-429.94**	~~400~~**384**
12	IROA**20**_SW**EB**	~~-166.9~~ **-292.13**	~~463~~**561**
12	LAND**40**	~~-355.3~~ **-454.07**	~~271~~**270**
12	MELK**40**_SW**EB**	~~-132.5~~ **-225.68**	~~82~~**84**
12	SEAB**40**	~~-92.38~~ **-130.89**	~~315~~**275**
12	**TAUN4A**	**-315.11**	**0**
12	TAUN**4B**	~~-245.8~~ **-317.3**	~~123~~**98**
		Totals	~~2724~~**2816**

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

(i) calculate the demand weighted nodal shadow costs

For zone 12 this would be as follows:

Demand zone	Node	Nodal Marginal km	Demand (MW)	Demand Weighted Nodal Marginal km
12	ABHA**4A**	-~~320.7~~**412.07**	~~267~~**137**	~~31.43~~**20.05**
12	**ABHA4B**	**-412.45**	**137**	**20.07**
12	ALVE**4A**	-~~318.7~~**362.07**	~~179~~**112**	~~20.94~~**14.41**
12	**ALVE4B**	**-373.75**	**112**	**14.87**
12	AXMI**40**_SW**EB**	-~~282.3~~**368.40**	~~100~~**107**	~~10.36~~**14.00**
12	BRWA**2A**	-~~248.2~~**340.96**	~~181~~**96.5**	~~16.49~~**11.68**
12	**BRWA2B**	**-341.09**	**96.5**	**11.69**
12	EXET**40**	-~~284~~**355.14**	~~317~~**320**	~~33.05~~**40.36**
12	HINP**20**	-~~219.1~~**289.76**	26	~~2.09~~**2.68**
12	INDQ**40**	-~~391.9~~**424.94**	~~400~~**384**	~~57.54~~**57.95**
12	IROA**20**_SW**EB**	-~~166.9~~**292.13**	~~463~~**561**	~~28.37~~**58.20**
12	LAND**40**	-~~355.3~~**454.07**	~~271~~**270**	~~35.35~~**43.54**
12	MELK**40**_SW**EB**	-~~132.5~~**225.68**	~~82~~**84**	~~3.99~~**6.73**
12	SEAB**40**	-~~92.38~~**130.89**	~~315~~**275**	~~10.68~~**12.78**
12	TAUN**4B**	-~~245.8~~**317.30**	~~123~~**98**	~~11.10~~**11.04**
		Totals	~~2724~~**2816**	~~261.39~~**340.05**

(ii) sum the demand weighted nodal shadow cost to give a zonal figure. For zone 12 this is shown in the above table and is ~~261.39~~**340.05**km.

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the ~~27:73~~**28:72** (approx) split of revenue recovery between generation and demand is retained.

For zone 12 this would be **say**:

~~261.39~~**340.05**km - (-~~64.08~~**127.41**km) = ~~325.47~~**467.46km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

(iv) calculate the transport tariff by multiplying the figure in (iii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For zone 12, assuming an expansion constant of £~~27.03~~**9.29**/MWkm **and a locational security factor of 1.9**:

$$\frac{\sout{325.47}\mathbf{467.46}\text{km} \times £\sout{27.03}\mathbf{9.29}/\text{MWkm} \times \mathbf{1.9}}{1000} = £\sout{8.80}\mathbf{8.25}/\text{kW}$$

(v) We now need to calculate the~~ security &~~ residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.7**2**~~3~~% of total National Grid TNUoS target revenue for the year) less the revenue which would be recovered through the demand transport tariffs divided by total expected demand.

Assuming the total revenue to be recovered from TNUoS is £~~650~~**785**m, the total recovery from demand would be (7**2**~~3~~% x £~~650~~**785**m) = £**565.2**~~474.5~~m. Assuming the total recovery from demand transport tariffs is £1**2**0~~0~~m and total forecast chargeable demand capacity is 50000MW, the demand~~ security &~~ residual tariff would be as follows:

$$\frac{£556.2m - £120m}{50000MW} = \underline{£8.72/kW}$$

(vi) to get to the final tariff, we simply add on the demand~~ security &~~ residual tariff calculated in (v) to the zonal transport tariff calculated in (iv)

For zone 12:

£8.**25**~~8~~ / kW + £~~7.49~~**8.72** / kW = **£16.97~~29~~/kW**

To summarise, in order to calculate the demand tariffs, we evaluate a demand weighted zonal marginal km cost, modify by a re-referencing quantity to ensure that our revenue recovery split between generation and demand is correct, then we add a constant (termed the~~ security +~~ residual cost) to give the overall tariff.

Appendix 12 - Proposed Changes to Appendix TN-4: Reconciliation of Demand Related Transmission Network Use of System Charges

Appendix TN-4: Reconciliation of Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by National Grid in the reconciliation of Transmission Network Use of System charges for demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

Monthly Peak Demand Charges

Suppliers provide half-hourly (HH) and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW and 1.20p/kWh, is as follows:

	Forecast HH Triad Demand HHD_F(kW)	HH Monthly Invoiced Amount (£)	Forecast NHH Energy Consumption $NHHC_F$(kWh)	NHH Monthly Invoiced Amount (£)	Net Monthly Invoiced Amount (£)
Apr	12,000	10,000	15,000,000	15,000	25,000
May	12,000	10,000	15,000,000	15,000	25,000
Jun	12,000	10,000	15,000,000	15,000	25,000
Jul	12,000	10,000	18,000,000	19,000	29,000
Aug	12,000	10,000	18,000,000	19,000	29,000
Sep	12,000	10,000	18,000,000	19,000	29,000
Oct	12,000	10,000	18,000,000	19,000	29,000
Nov	12,000	10,000	18,000,000	19,000	29,000
Dec	12,000	10,000	18,000,000	19,000	29,000
Jan	7,200	(6,000)	18,000,000	19,000	13,000
Feb	7,200	(6,000)	18,000,000	19,000	13,000
Mar	7,200	(6,000)	18,000,000	19,000	13,000
Total		72,000		216,000	288,000

As shown, for the first nine months the Supplier provided a 12,000kW HH triad demand forecast, and hence paid HH monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

Initial Reconciliation (Part 1)

The Supplier's outturn HH triad demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge

$$= (HHD_A - HHD_F) \times £/kW\ Tariff$$
$$= (9{,}000kW - 7{,}200kW) \times £10.00/kW$$
$$= 1{,}800kW \times £10.00/kW$$
$$\mathbf{= £18{,}000}$$

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12 month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.

As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge

$$= \frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$$
$$= \frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$$
$$= \frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$$
$$\mathbf{= -£12{,}000}$$

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,000 (£18,000 - £12,000).

Monthly Year Round Charges

This is a relatively straight forward process since charges are applied to outturn metered data the table below illustrates the process consistent with the data from the above example, assuming;

(i) the HH demand is a 12MW baseload which triad manages 4.8MW for 10 hours in each of December and January;

(ii) the NHH energy consumption for peak charges (16:00-19:00) accounts for 15% of total NHH energy consumption in summer months and 10% in winter months

	Outturn HH Metered Demand (MWh)	Outturn NHH Metered Demand (MWh)	Year Round Demand Charge (p/MWh)	Monthly Invoiced Amount for Relevant Year (£)	
April	8,640	100,000	18	-	
May	8,928	100,000	18	-	
June	8,640	100,000	18	19,555.20	
July	8,928	120,000	18	19,607.04	
August	8,928	120,000	18	19,555.20	
September	8,640	120,000	18	23,207.04	
October	8,928	180,000	18	23,207.04	
November	8,640	180,000	18	23,155.20	
December	8,880	180,000	18	34,007.04	
January	8,880	180,000	18	33,955.20	
February	8,064	180,000	18	33,998.40	
March	8,928	180,000	18	33,998.40	
April	-	-	-	33,851.52	
May	-	-	-	34,007.04	
TOTAL	105,024	1,740,000	-	332,084.32	

The table above illustrates the two month delay in invoicing for year round charges but that ultimately the user would see their full year round charge of £332,084.32 for the relevant year by May of the following year.

However due to the 2 month invoicing arrears, interest payments would be liable on each of the relevant monthly payments of the year round charge. These interest payments are calculated using the Barclays Base Rate applicable over the two month period between consumption and invoicing.

Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad demand and NHH energy consumption values were 9,500kW and 16,500,000kWh, respectively**, and that total annual metered consumption was 1,851,435MWh**.

Final HH Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final NHH Reconciliation Charge = $\frac{\text{(16,700,000kWh – 17,000,000kWh) x 1.20p/kWh}}{100}$
= -£3,600

Final YR reconciliation charge **= $\frac{\text{(1,851,435MWh – 1,845,035MWh) x 18p/MWh}}{100}$**

= £1,152

Consequently, the net final TNUoS demand reconciliation charge will be £~~1,400~~**2,552**.

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

Terminology:

HHD_A = The Supplier's outturn half-hourly metered Triad Demand (kW) for the demand zone concerned.

HHD_F = The Supplier's forecast half-hourly metered Triad Demand (kW) for the demand zone concerned.

$NHHC_A$ = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1^{st} to March 31^{st}, for the demand zone concerned.

$NHHC_F$ = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1^{st} to March 31^{st}, for the demand zone concerned.

£/kW Tariff = The £/kW Demand Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

p/kWh Tariff = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

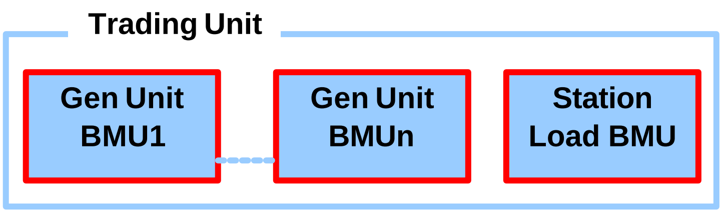
Appendix 13 – Proposed Changes to Appendix TN-5: Classification of parties for charging purposes

Appendix TN-5: Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

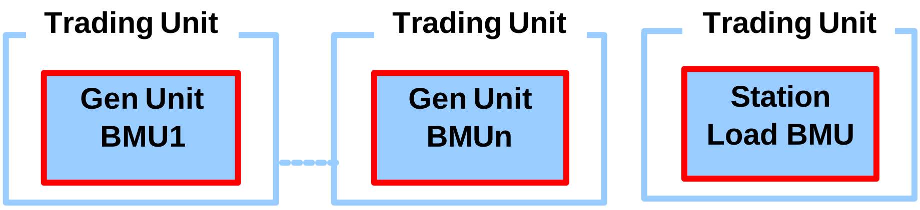
In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

LICENSABLE POWER STATION – SAME TRADING UNIT



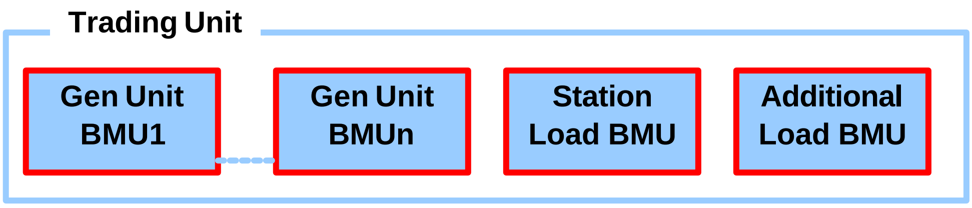
Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Licensable Power Stations, see **~~4~~5.5.**	See **~~5~~6.1 i)** and **ii).** For generators in positive zones, see **~~5~~6.4 to ~~5~~6.5.** For generators in negative zones, see **~~5~~6.4 and ~~5~~6.7.**

LICENSABLE POWER STATION – SEPARATE TRADING UNITS



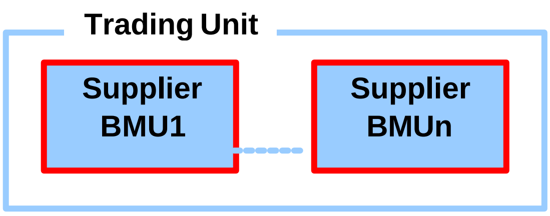
Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Licensable Power Stations, see **~~4~~5.5.**	See **~~5~~6.1 i)** and **ii).** For generators in positive zones, see **~~5~~6.4 to ~~5~~6.5.** For generators in negative zones, see **~~5~~6.4 and ~~5~~6.7.**

LICENSABLE POWER STATION WITH ADDITIONAL LOAD



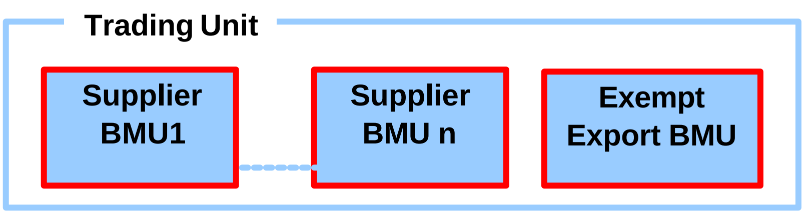
Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Licensable Power Stations, see **~~4~~5.5.**	See **~~5~~6.1 i)** and **ii).** For generators in positive zones, see **~~5~~6.4 to ~~5~~6.5.** For generators in negative zones, see **~~5~~6.4 and ~~5~~6.7.**

SUPPLIER BMU



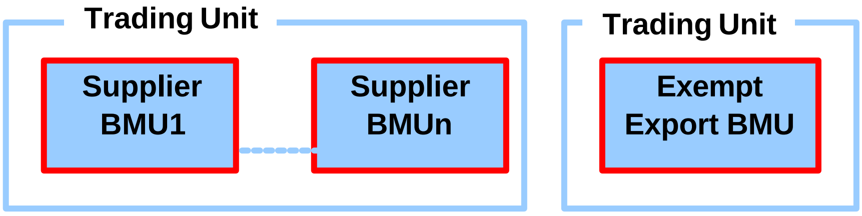
Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Supplier BMUs, see **~~4~~5.4.**	None.

SUPPLIER WITH EXEMPT EXPORT or DISTRIBUTION INTERCONNECTOR BMU – SAME TRADING UNIT



Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Supplier BMUs, see **~~4~~5.4.** For Lead Parties of Exempt Export or Derogated Distribution Interconnector BMUs, see **~~4~~5.6.**	None.

SUPPLIER WITH EXEMPT EXPORT or DISTRIBUTION INTERCONNECTOR BMU – SEPARATE TRADING UNITS

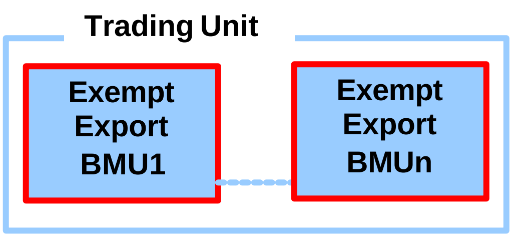


Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Supplier BMUs, see **45.4.** For Lead Parties of Exempt Export or Derogated Distribution Interconnector BMUs, see **45.6.**	None.

SOLE EXEMPT EXPORT or DEROGATED DISTRIBUTION INTERCONNECTOR BMU

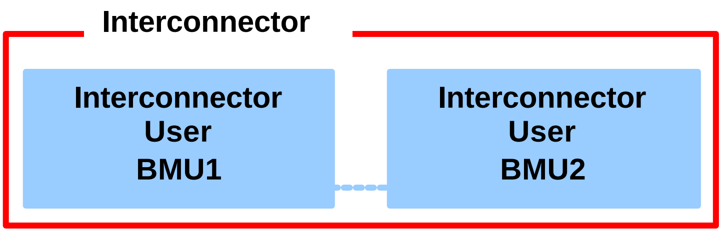
Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Exempt Export or Derogated Distribution Interconnector BMUs, see **45.6.**	None.

MULTIPLE EXEMPT EXPORT or DEROGATED DISTRIBUTION INTERCONNECTOR BMUs



Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Exempt Export or Derogated Distribution Interconnector BMUs, see **45.6.**	None.

INTERCONNECTOR ASSET OWNER



Demand Charges	Generation Charges
For Directly Connected Interconnectors see ~~4~~**5.7.**	See ~~5~~**6.1 iii)** and ~~5~~**6.4**. For Interconnectors in positive zones, see ~~5~~**6.6.** For Interconnectors in negative zones, see ~~5~~**6.7.**

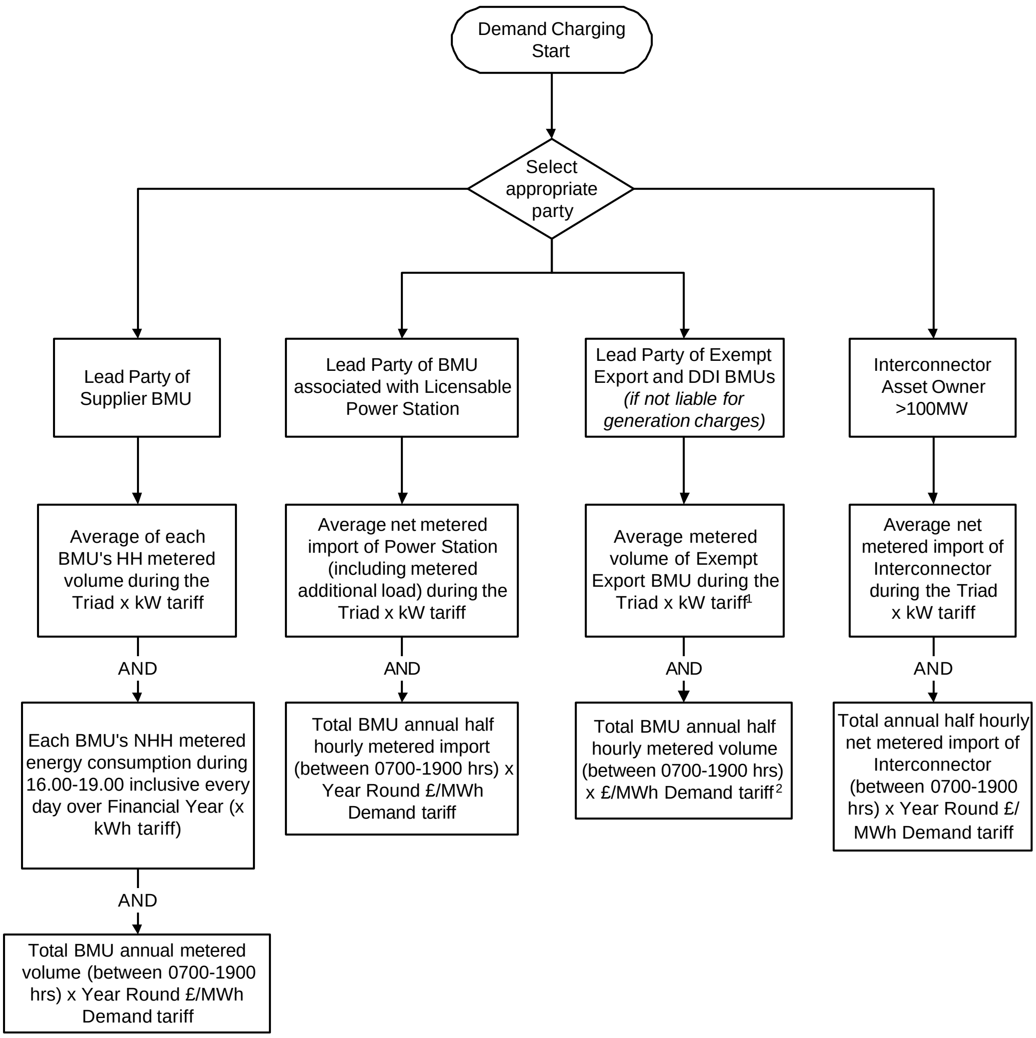
Appendix 14 – Proposed Changes to Appendix TN-6: Transmission Network Use of System Charging Flowcharts

Appendix TN-6: Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

Demand Charges

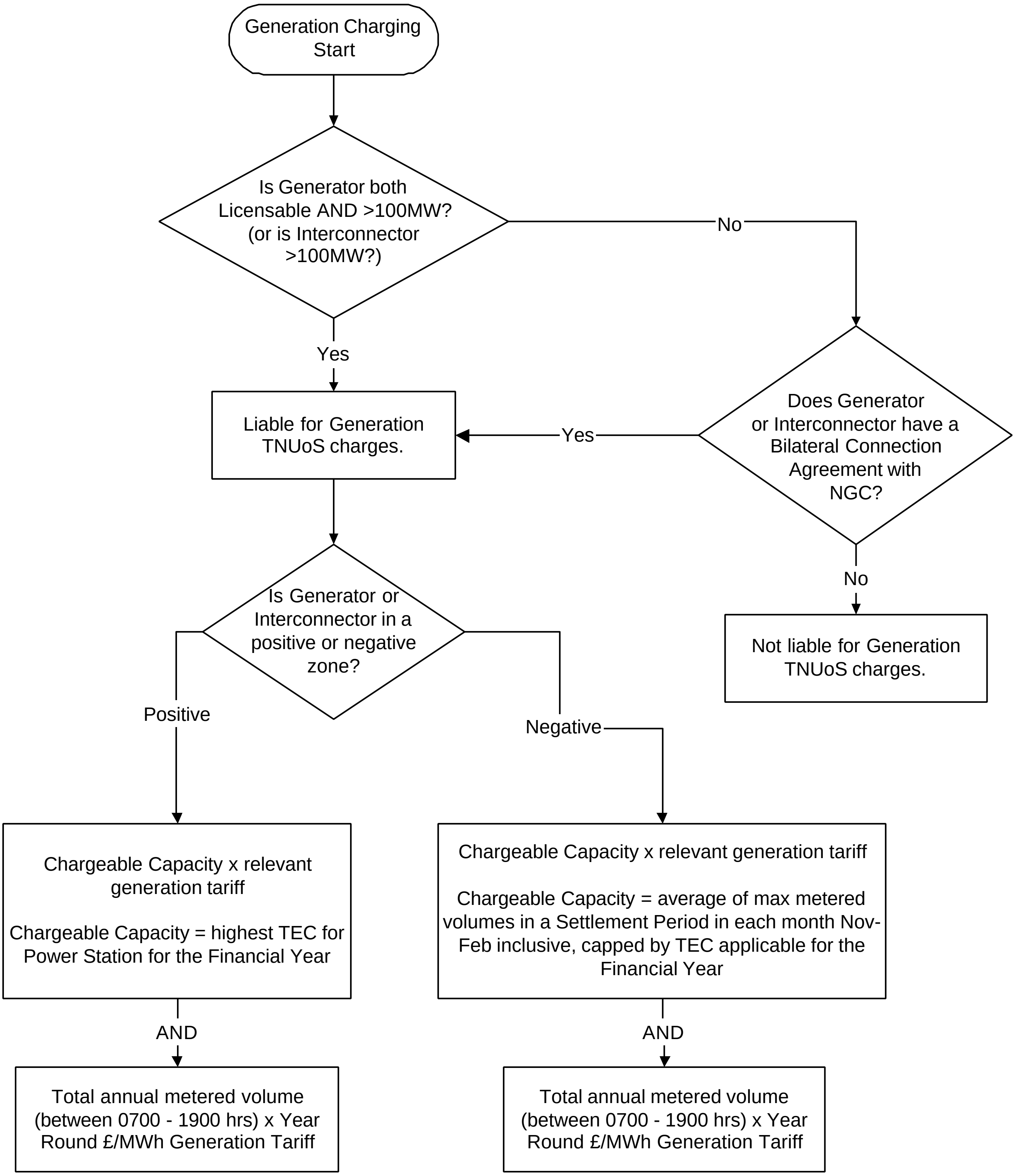


[1] If the average HH metered volume of the Exempt Export BMU over the Triad results in an import, the BMU will pay the amount of the average import x relevant kW tariff.
If the average HH metered volume of the Exempt Export BMU over the Triad results in an export, the BMU will be paid the amount of the average export x relevant kW tariff

[2] For any half hour period (between 0700-1900) where the Exempt Export BMU imports, the BMU will pay the relevant half hourly metered import volume x £/MWh demand tariff.
For any half hour period (between 0700-1900) where the Exempt Export BMU exports, the BMU will be paid the relevant half hourly metered export volume x £/MWh demand tariff.

BMU = BM Unit CVA = Central Volume Allocation DDI = Derogated Distribution Interconnector
HH = half hourly NHH = Non-half hourly

Generation Charges



BMU = BM Unit Max = maximum TEC = Transmission Entry Capacity