Issue	Revision
4	3

The Statement of the Use of System Charging Methodology

Effective from 1 November 2004

National Grid

About this Document

This document describes the methodology that National Grid Company plc (National Grid) employs to levy charges for use of its transmission system. This document is one of a suite of three documents that describe National Grid's charges and the methodologies behind them. The other documents that are available are:

- **The Statement of the Connection Charging Methodology**
- **The Statement of Use of System Charges**

These are available on our Charging website at:

www.nationalgrid.com/uk/indinfo/charging

This Statement of the Use of System Charging Methodology Issue 4, Revision 3 is effective from 1 November 2004.

This document has been published by National Grid in accordance with Standard Condition C5A of National Grid's Transmission Licence and is approved by the Gas and Electricity Markets Authority (the Authority).

This document is in three parts:

- A General Introduction
- The Statement of the Transmission Network Use of System Charging Methodology
- The Statement of the Balancing Services use of System Charging Methodology

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General Introduction

Licence Condition Objectives

1 The Use of System Charging Methodology has the following objectives as set out in Licence Standard Condition C5A 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 shallow basis as described by National Grid in its CCM-M-07 Connection Charging Methodology Modification document of 12 September 2003. 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 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;
- sign on to the Balancing and Settlement Code (BSC);
- 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 Amount.

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.

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 From April 2004, following an extensive review of the charging methodologies conducted by National Grid in consultation with Users, a number of further proposed changes were implemented:

i.) The introduction of a DC Loadflow (DCLF) ICRP 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.

1.8 These changes have not, however, 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.

1.9 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.

1.10 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' Transmission Entry Capacities (TECs) accommodated. The derivation of the incremental investment costs at different points on the system is 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.

1.11 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.

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

2.1 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. The combination of both these elements forms the TNUoS tariff. The process for calculating the 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
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The ratio of each of 132kV overhead line, 132kV cable, 275kV overhead line, 275kV cable and 400kV cable to 400kV overhead line costs to give circuit expansion factors
- Circuits 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 contracted Transmission Entry Capacity (TEC), at each node (based on the Applicable Value for year "t" in the April Seven Year Statement in year "t-1" plus updates to the October of year "t-1"). The contracted TECs in the Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with National Grid. For example for 2004/05 charges, the nodal generation data is based on the forecast for 2004/05 in the April 2003 Seven Year Statement plus any data included in the quarterly updates to October 2003).

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

2.7 The circuit lengths included in the transport model are solely those which relate to assets defined as 'use of system' assets.

2.8 The circuit expansion factors reflect the difference in cost between (i) cabled routes and overhead line routes, (ii) 132kV routes and 400kV routes, (iii) 275kV routes and 400kV routes, and (iv) 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 (specifically 400kV cable, 275kV overhead line, 275kV cable, 132kV overhead line and 132kV cable) is more expensive than for 400kV overhead line. This is done by effectively 'lengthening' these more expensive circuits by the relevant circuit expansion factor. This makes them more expensive within the model and hence reflects the additional costs of investing in these circuits compared to 400kV overhead line.

2.9 Circuits that 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 to these circuits.

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 DCLF ICRP, the reference node is currently at Pelham GSP.

Model Outputs

2.11 The transport model takes the inputs described above and firstly scales the nodal generation capacity uniformly such that total national generation (sum of contracted TECs) 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 network MWkm, using the relevant circuit expansion factors as appropriate.

2.12 Using this baseline network, 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 then 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 km.

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

Calculation of zonal marginal km

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 reviewed during the 1996 Price Control Review in line with the connections terms review. There were 16 generation zones, as required by the Director in his October 1996 Price Control proposals, and 12 demand zones relating to the 12 Public Electricity Supply areas.

2.15 Typically, generation zones will be 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. Following the 2002/03 Charging Review, the generation zones were reviewed to consider the impact of the changes to the methodology outlined in paragraph 1.7 of this statement. As a result of this review, there were changes to the overall geographical definition of the zones, although the total number of zones did not change. The 12 demand zones also remain intact due to practical constraints imposed by metering.

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

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

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

Where

nj	=	Number of nodes in generation zone Gi

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

2.19 A number of criteria are used to determine the definition of the generation zones. The main principles used since 1992, when the ICRP charging methodology was introduced, 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, the relevant expansion constant and the locational security factor, see below) are all within +/-£1/kW (2004/05 prices) across the zone. This means a maximum spread of £2/kW in 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.

2.20 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.

2.21 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence.

Deriving the Final £/kW Tariff

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 1 MW over 1 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, to provide 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 manufacturers' budgetary prices, contracts let and lead tenders. A range of overhead line types is used and the types are weighted by recent usage on the transmission system.

ii.) At the beginning of a price control period, an expansion constant figure using a 5 year average is calculated

iii.) This average figure sets the expansion constant for the first year of the price control period and this value is increased by RPI (May–October average increase, as defined in National Grid's Transmission Licence) for each subsequent year within the price control period

iv.) Allowances for engineering and interest costs are added

v.) The capital cost figures are converted into annuities

iv.) An addition is made for the cost of maintenance.

2.24 As an illustration the expansion constant calculated for 2004/05 is £9.51/MWkm. The circuit expansion factors calculated for 2004/05 (and rounded to 2 decimal places) are:

400kV cable factor:	26.40
275kV cable factor:	26.21
132kV cable factor:	36.75
400kV line factor:	1.00
275kV line factor:	1.74
132kV line factor:	2.61

2.25 These expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant.

In calculating the cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed.

The Locational Security Factor

2.26 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 can be met despite N-1 and N-2 contingencies (simulating single and double circuit faults) 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.

2.27 The maximum nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor.

2.28 The locational security factor derived for 2004/05 is 1.9.

Initial Transport Tariff

2.29 First an Initial Transport Tariff (ITT) must be calculated. For Generation the zonal marginal km (ZMkm) are simply multiplied by the expansion constant and the locational security factor 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

2.30 Similarly, for demand the zonal marginal km (ZMkm) are simply multiplied by the expansion constant and the locational security factor 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

2.31 The next step is to multiply these initial transport tariffs by the expected metered triad demand and generation capacity to gain an estimate of the initial revenue recovery. 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)

2.32 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)

2.33 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 Residual Tariff

2.34 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. Hence in any given year t, a target revenue figure for TNUoS charges (TRR_t) is set as follows:

$$TRR_{t}=R_{t}-PVC_{t}$$

Where
TRR_t = TNUoS Revenue Recovery target for year t
R_t = Forecast Revenue allowed under National Grid’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 AA5A of National Grid’s Transmission Licence.
PVC_t = Forecast Revenue from Pre-Vesting connection charges for year t

2.35 In normal circumstances, the revenue forecast to be recovered from the corrected 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.

2.36 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. 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

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

Final £/kW Tariff

2.37 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 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

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

2.39 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.

2.40 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.

2.41 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**.

2.42 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**.

2.43 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.

Chapter 3: Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Transmission Entry Capacity Tariff

TNUoS Energy Consumption Tariff

3.1 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.

3.2 Following calculation of the Transmission Network Use of System £/kW Demand Tariff (as outlined in **Chapter 2: Derivation of the Transmission Network Use of System Tariff**) the p/kWh energy consumption tariff for each GSP Group is calculated as follows:

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

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.

Short Term Transmission Entry Capacity

3.3 The Short Term Transmission Entry Capacity tariff for positive zones is derived from the relevant annual generation TNUoS £/kW tariff. The premium associated with the flexible product is based on 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

3.4 For the avoidance of doubt, the charge calculated under 3.3 above will represent each single period application for Short Term Transmission Entry Capacity. Requests for multiple STTEC periods will result in each STTEC period being calculated and invoiced separately.

3.5 The STTEC tariff for negative zones 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.

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

Chapter 4: Demand Charges

Parties Liable for Demand Charges

4.1 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 **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 The values of Triad demand (kW) and energy consumption (kWh) to be multiplied by the relevant demand or energy consumption tariff, for the calculation of demand charges, are set out below.

Supplier BM Unit

4.4 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 p/kWh tariff).

Licensable Power Station

4.5 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.

Exempt Export BM Unit & Derogated Distribution Interconnector BM Unit

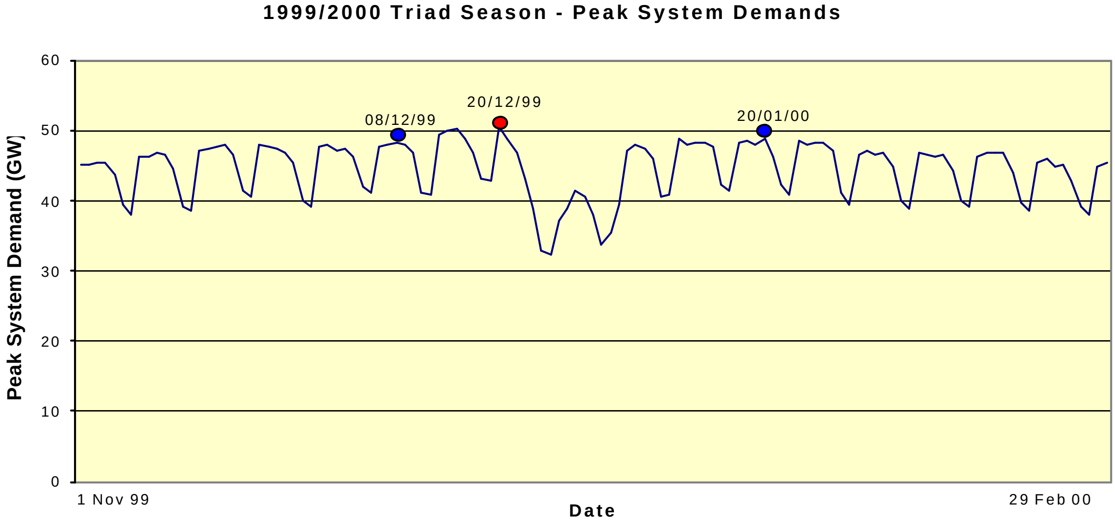
4.6 The demand charges for an Exempt Export BM Unit or Derogated Distribution Interconnector BM Unit will be based on the average of the metered volume of the Exempt Export BM Unit or Derogated Distribution Interconnector BM Unit during the Triad.

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

4.7 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 Triad

4.8 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 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

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 The output of generators and Distribution Interconnectors registered 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 Throughout the year Users' monthly demand charges will 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

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. 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.

4.12 Users should submit reasonable demand forecasts in accordance with the CUSC. National Grid 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. National Grid will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad demand for the preceding Financial Year will be used where User settlement data is available and where National Grid calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) demand in the Financial Year to date is compared to the equivalent average demand for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH demand at Triad in the preceding Financial Year to derive a forecast of the User's HH demand 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) demand over the last complete month for which National Grid has settlement data is calculated. Total system average HH demand for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH demand at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH demand for weekday settlement period 35 over the last month to derive a forecast of the User's HH demand 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 National Grid 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.

4.13 **Appendix TN-7: Example: Determination of National Grid's Forecast for Demand Charge Purposes** illustrates how the demand forecast will be calculated by National Grid.

Reconciliation of Demand Charges

4.14 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.

Initial Reconciliation of demand charges

4.15 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 Part 1– Half-hourly metered demand

4.16 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.

4.17 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 Part 2 – Non half-hourly metered demand

4.18 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 (p/kWh) 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

4.19 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).

4.20 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

4.21 **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.

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

4.23 **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.

Chapter 5: Generation charges

Parties Liable for Generation Charges

5.1 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 **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 Generation Charges

5.3 The value of generation to be multiplied by the relevant generation tariff, for the calculation of 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 The basis of the generation charge for Power Stations and Interconnectors is the Chargeable Capacity and the short term chargeable capacity (as defined below for positive and negative charging zones).

Positive Charging Zones

5.5 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. 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).

5.6 The short term chargeable capacity for Power Stations situated in positive charging zones is any approved STTEC applicable to that Power Station during a valid STTEC Period.

5.7 The Chargeable Capacity for an Interconnector connected to a positive charging zone is the highest TEC applicable to that Interconnector for that Financial Year. An Interconnector 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).

5.8 The short term chargeable capacity for an Interconnector connected to a positive charging zone is any approved STTEC applicable to that Interconnector during a valid STTEC Period.

Negative Charging Zones

5.9 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 5.10 below, for the Power Station (i.e. the sum of the metered volume of each BM Unit associated with Power Station) or Interconnector. A Power Station or Interconnector 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). If TEC is exceeded, the metered volumes would each be capped by the TEC for the Power Station or Interconnector applicable for that Financial Year.

5.10 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 do 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:

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

Note that in the example above, the Generator has exceeded its TEC on 13 December 2002 and 6 February 2003 and would therefore be in breach of the CUSC.

5.11 The short term chargeable capacity for Power Stations situated in negative charging zones is any approved STTEC applicable to that Power Station during a valid STTEC Period.

Monthly Charges

5.12 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 taking the forecast Chargeable Capacity and multiplying it by the zonal £/kW tariff. This annual TNUoS generation charge is split evenly over the 12 months and charged on a monthly basis over the year. 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. As a result, if TEC increases, monthly payments to the generator will increase accordingly, and if TEC decreases, monthly payments will fall accordingly.

Ad hoc Charges

5.13 For each STTEC period successfully applied for, a charge will be calculated by multiplying the Short Term Transmission Entry Capacity by the tariff calculated in accordance with Paragraph 3.3. National Grid will invoice Users for the STTEC charge once the application for STTEC is approved in accordance with the CUSC.

Reconciliation of Generation Charges

5.14 The reconciliation process is set out in the CUSC.

Further Information

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

Chapter 6: Data Requirements

Data Required for Charge Setting

6.1 Users who are Generators or Interconnector Asset Owners 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 TNUoS tariffs. National Grid may request these forecasts in the November prior to the Financial Year to which they relate, in accordance with the CUSC.

6.2 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 For the following Financial Year, National Grid 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 **Chapter 2: Derivation of the Transmission Network Use of System Tariff**.

6.4 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 In order for National Grid to calculate Users' 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 and 4.12 and in accordance with the CUSC.

Chapter 7: Applications

7.1 Application fees are payable in respect of applications for new use of system agreements, modifications to existing agreements and applications for STTEC 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 For the avoidance of doubt, the STTEC Request Fee is fixed and is non-refundable in accordance with the CUSC.

7.3 If a User chooses not to pay the fixed fee, the application fee will be based on 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.

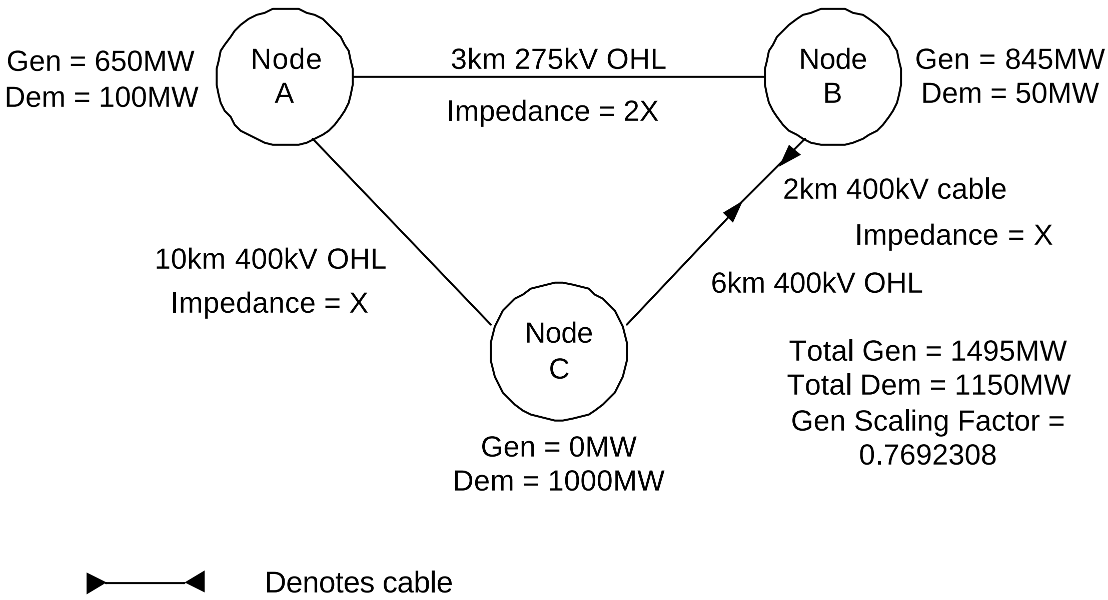
7.4 With the exception of the STTEC Request Fee, National Grid will refund application fees and consent payments made under the Construction Agreement either on commissioning or against the charges payable in the first three years of the new or modified agreement. The following conditions apply:

- 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 TN-1: 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.

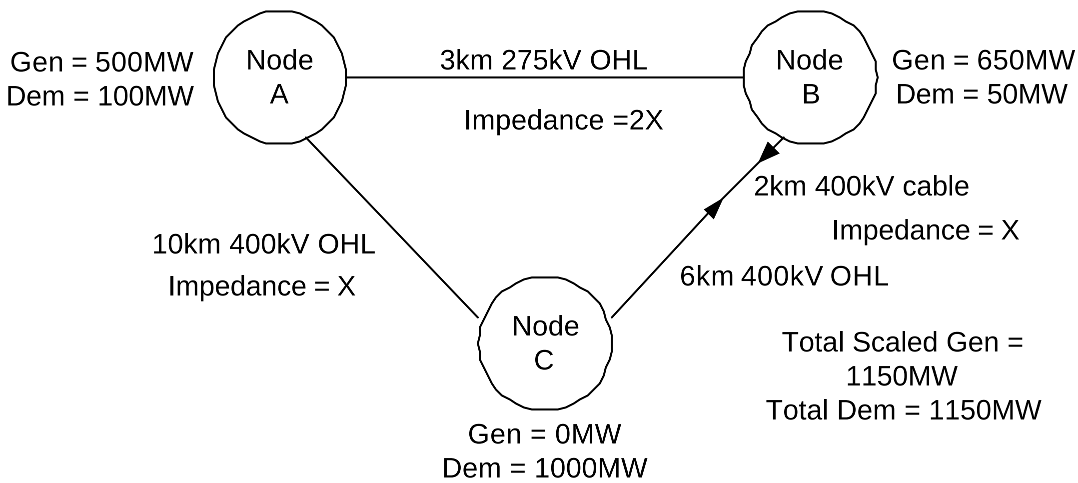
Consider the following 3 node network:



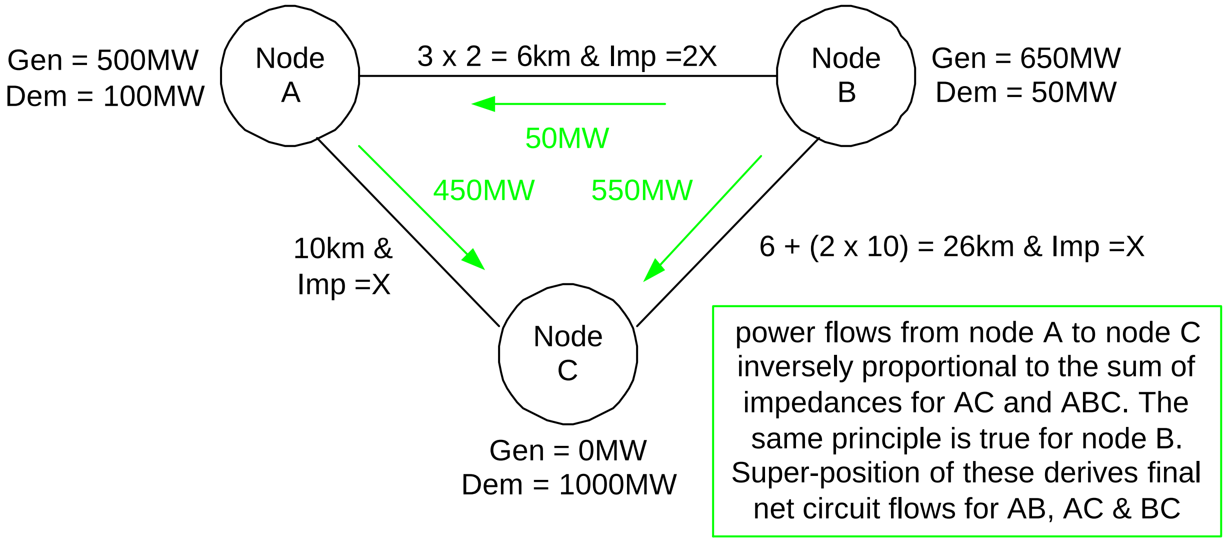
The first step is to match total demand and total generation by scaling uniformly the nodal generation down such that total system generation equals total system demand.

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 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 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 400MW; route AC has impedance X and route AB-BC has impedance 3X; hence 300MW would flow down AC and 100MW along AB-BC

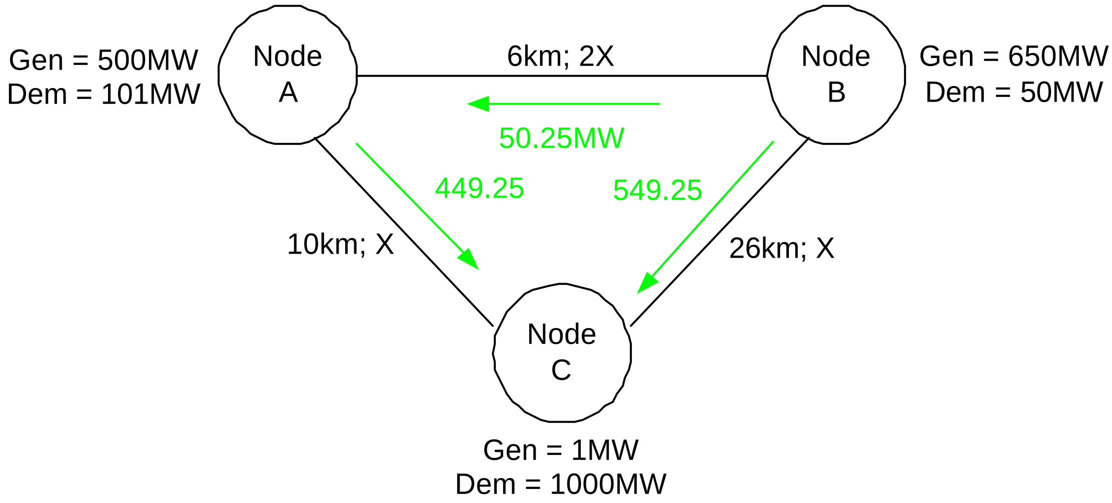
Step 2: Net export from Node B is 600MW; route BC has impedance X and route BA-AC has impedance 3X; hence 450MW would flow down BC and 150MW along BA-AC

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

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

Total cost = (450 x 10) + (50 x 6) + (550 x 26) = 19,100 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 x 10) + (50.25 x 6) + (549.25 x 26) = 19,074.5 MWkm

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

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

Let us consider all nodes in generation zone 7: Rest of Mids & 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.

Genzone	Node	Nodal Marginal km	Scaled Generation
7	BRAI4A	105.37	0
7	BRFO40	118.89	0
7	BURW40	110.86	0
7	EASO40	112.99	552.02
7	GREN40_EME	79.56	321.55
7	GREN40_EPN	79.56	0
7	NORW40	108.96	332.64
7	SIZE40	157.43	1338.48
7	SPLN40	186.18	0
7	SUND40	35.14	0
7	WALP40_EME	164.24	0
7	WALP40_EPN	164.24	1257.70
7	WYMO40	74.74	0
		Totals	3802.39

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 this would be as follows:

Genzone	Node	Nodal Marginal km	Scaled Generation (MW)	Gen Weighted Nodal Marginal km
7	EASO40	112.99	552.02	16.40
7	GREN40_EME	79.56	321.55	6.73
7	NORW40	108.96	332.64	9.53
7	SIZE40	157.43	1338.48	55.42
7	WALP40_EPN	164.24	1257.70	54.32
		Totals	3802.39	

i.e. $\dfrac{157.43 \times 1338.48}{3802.39}$

(ii) sum the generation weighted nodal shadow cost to give a zonal figure. For zone 7 this would be:

(16.40 + 6.73 + 9.53 + 55.42 + 54.32) km = **142.40 km**

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

For zone 7 this would be say:

142.40km + (-127.61km) = **14.79 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 £9.51/MWkm and a locational security factor of 1.9:

$$\frac{14.79\text{km} * £9.51/\text{MWkm} * 1.9}{1000} = \underline{\mathbf{£0.27/kW}}$$

(v) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from generation (calculated as c.27% 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 £785m, the total recovery from generation would be (27% x £785m) = £211.95m. Assuming the total recovery from generation transport tariffs is £45m and total forecast chargeable generation capacity is 62000MW, the Generation residual tariff would be as follows:

$$\frac{£211.95m - £45m}{62000MW} = \underline{£2.69/kW}$$

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

For zone 7:

-£0.27/kW + £2.69/kW = **£2.96/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, multiply by the security factor, then we add a constant (termed the residual cost) to give the overall 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	ABHA4A	-412.07	137
12	ABHA4B	-412.45	137
12	ALVE4A	-362.07	112
12	ALVE4B	-373.75	112
12	AXMI40_SWEB	-368.40	107
12	BRWA2A	-340.96	96.5
12	BRWA2B	-341.09	96.5
12	EXET40	-355.14	320
12	HINP20	-289.76	26
12	HINP40	-289.76	0
12	INDQ40	-429.94	384
12	IROA20_SWEB	-292.13	561
12	LAND40	-454.07	270
12	MELK40_SWEB	-225.68	84
12	SEAB40	-130.89	275
12	TAUN4A	-315.11	0
12	TAUN4B	-317.3	98
		Totals	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	ABHA4A	-412.07	137	20.05
12	ABHA4B	-412.45	137	20.07
12	ALVE4A	-362.07	112	14.41
12	ALVE4B	-373.75	112	14.87
12	AXMI40_SWEB	-368.40	107	14.00
12	BRWA2A	-340.96	96.5	11.68
12	BRWA2B	-341.09	96.5	11.69
12	EXET40	-355.14	320	40.36
12	HINP20	-289.76	26	2.68
12	INDQ40	-424.94	384	57.95
12	IROA20_SWEB	-292.13	561	58.20
12	LAND40	-454.07	270	43.54
12	MELK40_SWEB	-225.68	84	6.73
12	SEAB40	-130.89	275	12.78

12	TAUN4B	-317.30	98	11.04
		Totals	2816	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 340.05km.

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

For zone 12 this would be say:

340.05km - (-127.41km) = **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 £9.51/MWkm and a locational security factor of 1.9:

$$\frac{467.46\text{km} * £9.51/\text{MWkm} * 1.9}{1000} = \underline{\mathbf{£8.45/kW}}$$

(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 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 £785m, the total recovery from demand would be (73% x £785m) = £573.05m. Assuming the total recovery from demand transport tariffs is £120m and total forecast chargeable demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£573.05m - £120m}{50000MW} = \underline{£9.06/kW}$$

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

For zone 12:

£8.45 / kW + £9.06 / kW = **£17.51/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 residual cost) to give the overall tariff.

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 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 <u>initial</u> 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) x £10.00/kW
= 1,800kW x £10.00/kW
= £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

$$= \frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$$

$$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$$

$$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$$

= -£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).

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.

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

Final NHH Reconciliation Charge

$$= \frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$$

= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,400.

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.

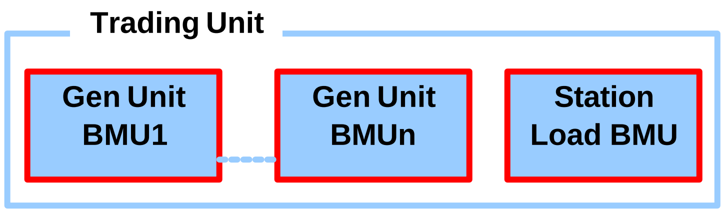
p/kWh Tariff = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

Appendix 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.

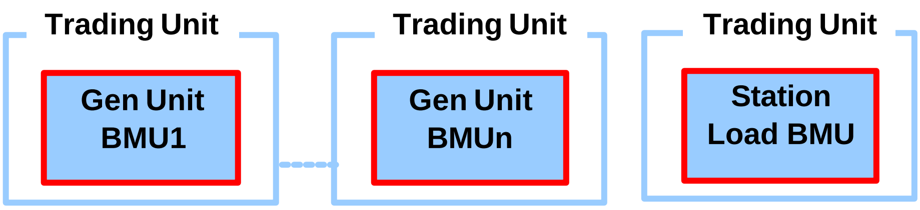
In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

LICENSABLE POWER STATION – SAME TRADING UNIT



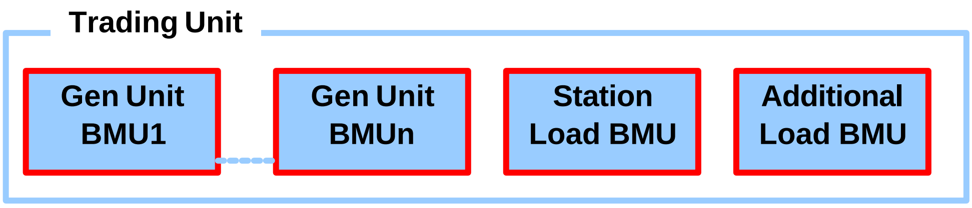
Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Licensable Power Stations, see **4.5.**	See **5.1 i)** and **ii).** For generators in positive zones, see **5.3 to 5.5.** For generators in negative zones, see **5.3 to 5.4 and 5.7 to 5.8.**

LICENSABLE POWER STATION – SEPARATE TRADING UNITS



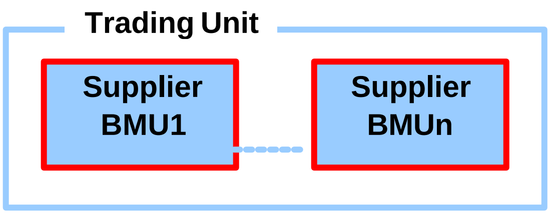
Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Licensable Power Stations, see **4.5.**	See **5.1 i)** and **ii).** For generators in positive zones, see **5.3 to 5.5.** For generators in negative zones, see **5.3 to 5.4 and 5.7 to 5.8.**

LICENSABLE POWER STATION WITH ADDITIONAL LOAD



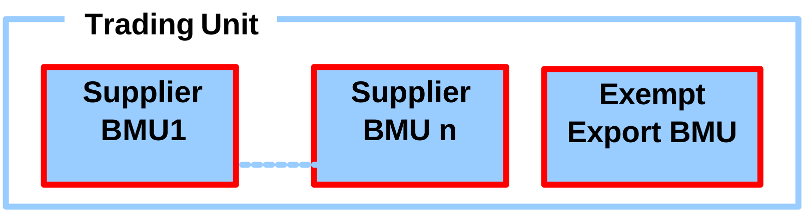
Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Licensable Power Stations, see **4.5.**	See **5.1 i)** and **ii).** For generators in positive zones, see **5.3 to 5.5.** For generators in negative zones, see **5.3 to 5.4 and 5.7 to 5.8.**

SUPPLIER BMU



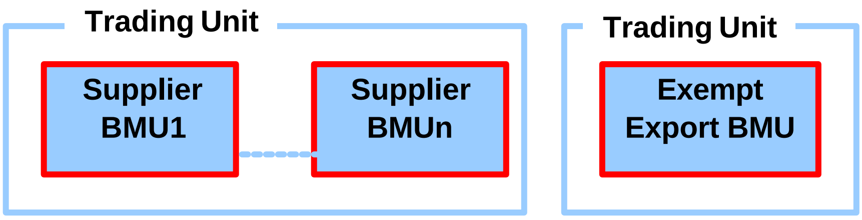
Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Supplier BMUs, see **4.4.**	None.

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 **4.4.** For Lead Parties of Exempt Export or Derogated Distribution Interconnector BMUs, see **4.6.**	None.

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

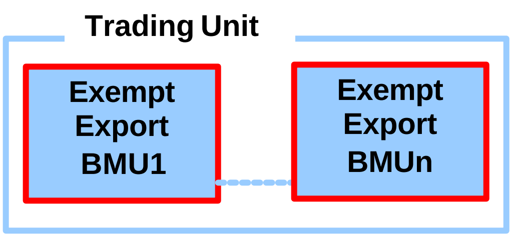


Demand Charges	Generation Charges
All Lead Parties of BMUs shall be liable for Demand TNUoS charges. For Lead Parties of Supplier BMUs, see **4.4.** For Lead Parties of Exempt Export or Derogated Distribution Interconnector BMUs, see **4.6.**	None.

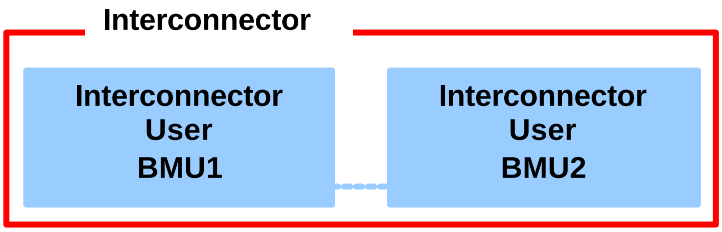
SOLE EXEMPT EXPORT or DEROGATED DISTRIBUTION INTERCONNECTOR BMU

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 **4.6.**	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 **4.6.**	None.

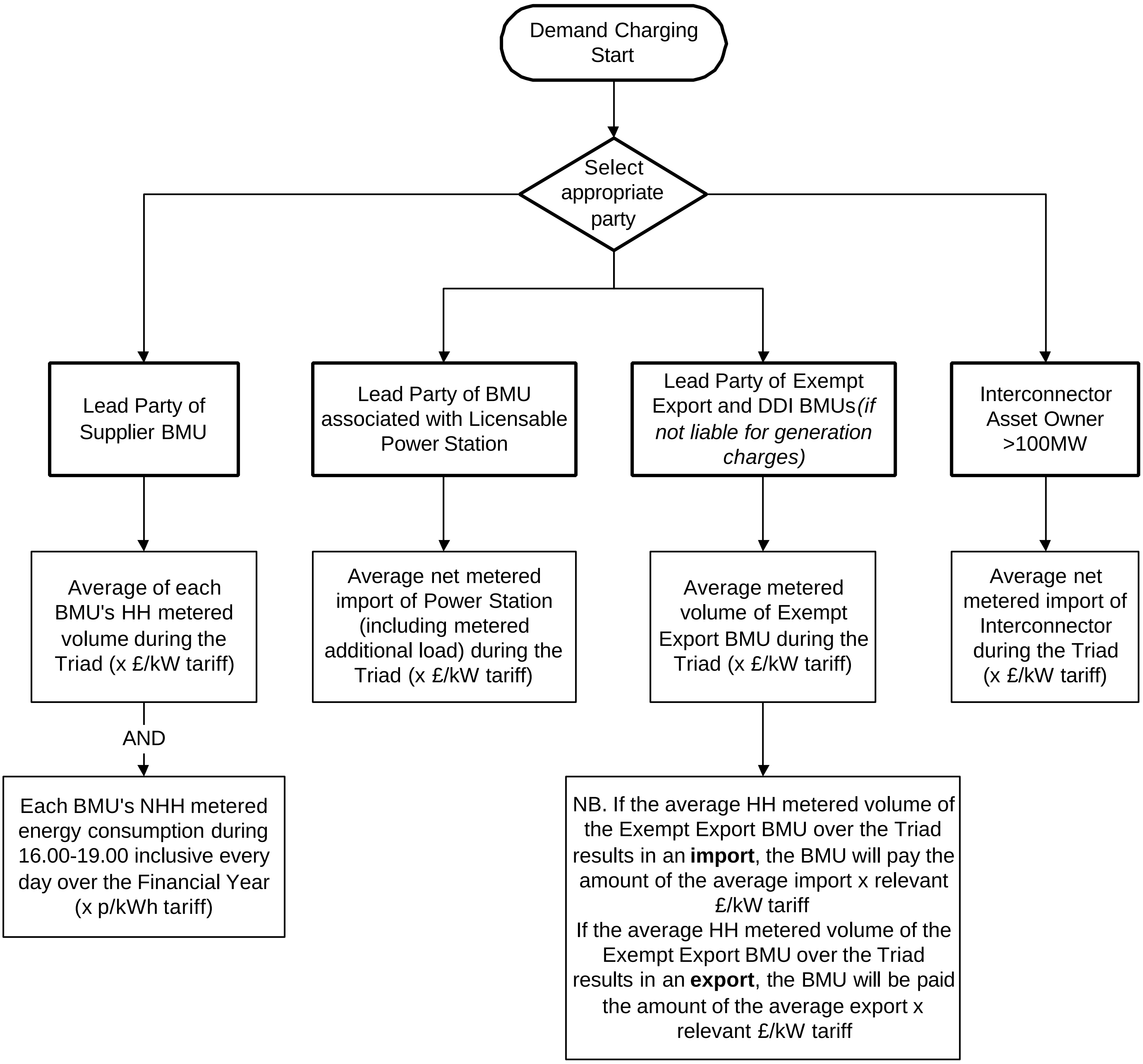
INTERCONNECTOR ASSET OWNER	
	
Demand Charges For Directly Connected Interconnectors see **4.7.**	Generation Charges See **5.1 iii)** and **5.4**. For Interconnectors in positive zones, see **5.6.** For Interconnectors in negative zones, see **5.7 to 5.8.**

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.

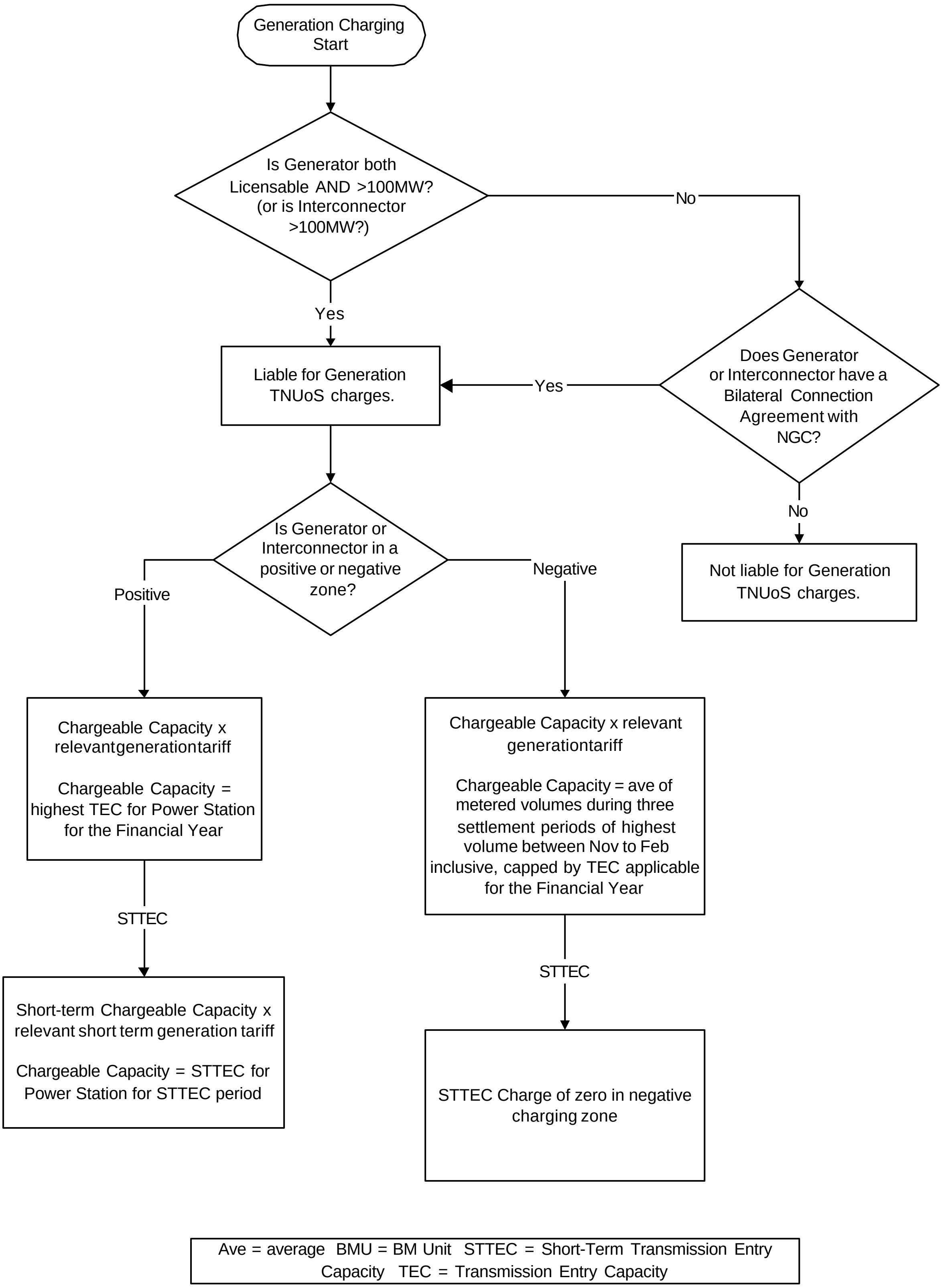
In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

Demand Charges



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

Generation Charges



Appendix TN-7: Example: Determination of National Grid's Forecast for Demand Charge Purposes

National Grid will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2004 to March 2005 is used.

Where the preceding year's settlement data is not available at the time that National Grid needs to calculate its forecast, National Grid will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), National Grid will be aware at a system level which dates will be used for the determination of Triad. However, National Grid may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, National Grid will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

$F = T$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH demand at Triad in Financial Year minus one

Where National Grid determines its forecast within a Financial Year:

$F = T * D/P$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH demand at Triad in the preceding Financial Year

D = User's average half hourly metered demand in settlement period 35 in the Financial Year to date

P = User's average half hourly metered demand in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where National Grid determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, National Grid shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH demand at Triad in the Financial Year minus two

D = User's average half hourly metered demand in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered demand in settlement period 35 for the period corresponding to D in the Financial Year minus two

Example (where User settlement data is not yet available for the Triad period):

National Grid calculates a HH demand forecast on the above methodology at 10th March 2004 for the period 1st April 2004 to 31st March 2005.

F = 10,000 * 13,200 / 12,000

F = 11,000 kWh

where:

T = 10,000 kWh (period November 2002 to February 2003)

D = 13,200 kWh (period 1st April 2003 to 15th February 2004#)

P = 12,000 kWh (period 1st April 2002 to 15th February 2003)

Latest date for which settlement data is available.

ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

Example:

National Grid calculates a NHH energy consumption forecast on the above methodology at 10th June 2004 for the period 1st April 2004 to 31st March 2005.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2003 to 31st March 2004)

D = 4,400,000 kWh (period 1st April 2004 to 15th May 2004#)

P = 4,000,000 kWh (period 1st April 2003 to 15th May 2003)

Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, National Grid would in the above example use values for E and P from Financial Year 2002/03 and D from Financial Year 2003/04.

iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered demand at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH demand at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

Example:

National Grid calculates a HH demand forecast on the above methodology at 10th September 2004 for a new User registered from 10th June 2004 for the period 10th June 2004 to 31st March 2005.

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kWh

where:

M = 1,000 kWh (period 1st July 2004 to 31st July 2004)

T = 17,000,000 kWh (period November 2003 to February 2004)

W = 18,888,888 kWh (period 1st July 2003 to 31st July 2003)

iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

Example:

National Grid calculates a NHH energy consumption forecast on the above methodology at 10th September 2004 for a new User registered from 10th June 2004 for the period 10th June 2004 to 31st March 2005.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2004 to 30th June 2004)

M = 1,000 kWh (period 1st July 2004 to 31st July 2004)

R = 20,000,000,000 kWh (period 1st July 2003 to 31st March 2004)

W = 2,000,000,000 kWh (period 1st July 2003 to 31st July 2003)

The Statement of the Balancing Services Use of System Charging Methodology

Chapter 8: Principles

8.1 The Transmission Licence allows National Grid to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

8.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by National Grid as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

8.3 National Grid in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). National Grid is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

8.4 All CUSC Parties are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period.

8.5 BSUoS charges comprise the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to National Grid associated with Manifest Errors and Special Provisions.

Chapter 9: Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

9.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}$$

Where:

i	-	refers to the individual BM Unit
j	-	refers to an individual Settlement Period
$\sum_{i \in c} \sum_{j \in d}$	-	refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party summed over all Settlement Periods 'j' on a Settlement Day 'd'

9.2 A customer's charge is based on their proportion of BM Unit Metered Volume for each Settlement Period relative to the total BM Unit Metered Volume for each Settlement Period, adjusted for transmission losses by the application of the relevant Transmission Losses Multiplier.

For importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$BSUoSTOT_{ij} = \frac{BSUoSTOT_j * QM_{ij} * TLM_{ij}}{\left\{ \left| \sum^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QM_{ij} * TLM_{ij}) \right| \right\}}$$

For importing and exporting BM Units in offtaking Trading Units in a Settlement Period:

$$BSUoSTOT_{ij} = \frac{-1 * BSUoSTOT_j * QM_{ij} * TLM_{ij}}{\left\{ \left| \sum^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QM_{ij} * TLM_{ij}) \right| \right\}}$$

Where:

$\sum^{+}$	-	refers to the sum over all BM Units that are in delivering Trading Units in Settlement Period 'j'
$\sum^{-}$	-	refers to the sum over all BM Units that are in offtaking Trading Units in Settlement Period 'j'

'delivering' and 'offtaking' in relation to Trading Units have the meaning set out in the Balancing and Settlement Code

9.3 For the avoidance of doubt, BM Units that are registered in Trading Units will be charged on a net Trading Unit basis i.e. if a BM Unit is exporting to the system and is within a Trading Unit that is offtaking from the system then the BM Unit in essence would be paid the BSUoS charge. Conversely, if a BM Unit is importing from the system in a delivering Trading Unit then the BM Unit in essence would be paid the

BSUoS charge. Note this includes the Interconnector BM Units that belong to the Interconnector Error Administrator.

Interconnector BM Units

9.4 The Lead Party of an Interconnector BM Unit will be liable for BSUoS charges based on their proportion of the total BM Unit Metered Volume of each Settlement Period adjusted for Transmission Losses by the application of the relevant Transmission Losses Multiplier.

Total BSUoS Charge (Internal + External) for each Settlement Period ($BSUoSTOT_{jd}$)

9.5 The Total BSUoS charges for each Settlement Period ($BSUoSTOT_{jd}$) for a particular day are calculated by summing the external BSUoS charge ($BSUoSEXT_{jd}$) and internal BSUoS charge ($BSUoSINT_{jd}$) for each Settlement Period.

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

External BSUoS Charge for each Settlement Period ($BSUoSEXT_{jd}$)

9.6 The External BSUoS Charges for each Settlement Period ($BSUoSEXT_{jd}$) are calculated by taking each Settlement Period System Operator BM Cash Flow ($CSOBM_j$) and Balancing Service Variable Contract Cost ($BSCCV_j$) and allocating the daily elements on a MWh basis across each Settlement Period in a day.

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd} + \Big[\ (IncpayEXT_d + BSCCA_d + ET_d - OM_d)$$
$$*\Big\{ \Big|\sum^{+}(QM_{ijd} * TLM_{ijd})\Big| + \Big|\sum^{-}(QM_{ijd} * TLM_{ijd})\Big| \Big\} / \sum_{j\in d}\Big\{ \Big|\sum^{+}(QM_{ijd} * TLM_{ijd})\Big| + \Big|\sum^{-}(QM_{ijd} * TLM_{ijd})\Big| \Big\}\ \Big]$$

Calculation of the daily External Incentive Payment ($IncpayEXT_d$)

9.7 In respect of each Settlement Day d, $IncpayEXT_d$ is calculated as the difference between the new total incentive payment ($FKIncpayEXT_d$) and the incentive payment that has been made to date for the previous days from the commencement of the scheme ($\xi_{k=1\equiv d-1} IncpayEXT_k$):

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

9.8 The forecast incentive payment made to date (from the commencement of the scheme) ($FKIncpayEXT_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

9.9 The value PFT_d of each Settlement Day is the value in the column PFT_d which appears against a period of time during which Settlement Day_d falls. All PFT_d are assumed to be one for the duration of the incentive scheme.

9.10 The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External

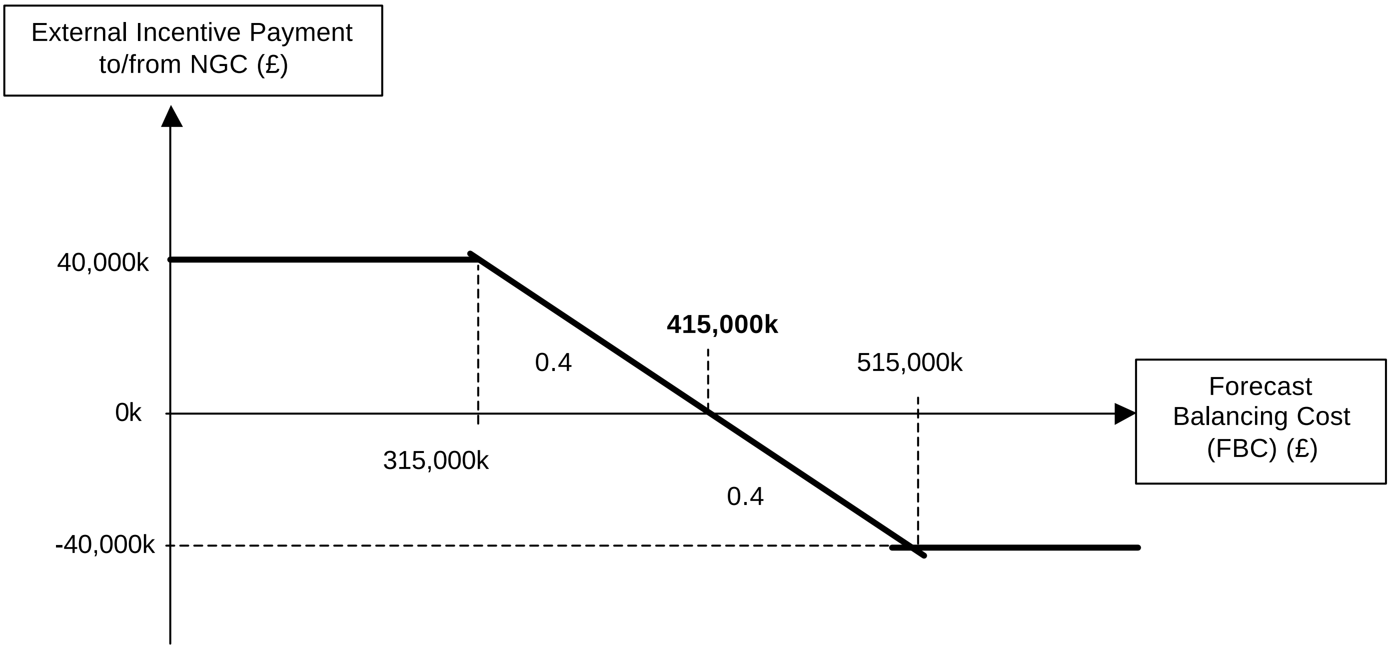
Scheme target (BPext) and the forecast Balancing cost (FBC) subject to sharing factors (SFext) and a cap/collar (OSext).

$$FYIncpayEXT_d = SFext * (BPext - FBC_d) + OSext$$

9.11 The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

Table 9.1

Forecast Balancing Cost (FBC)	BPext	SFext	OSext
< £315,000,000	£0	0	£40,000,000
£315,000,000 <=FBC < £415,000,000	£415,000,000	0.4	£0
£415,000,000 <= FBC < £515,000,000	£415,000,000	0.4	£0
>= £515,000,000	£0	0	-£40,000,000



9.12 In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS: Number of days in Scheme.

9.13 Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

$$IBC_d = \sum_{j \in d} (CSOBM_{jd} + BSCCV_{jd} + NI_{jd} + TL_{jd}) + BSCCA_d - OM_d - RT_d$$

Internal BSUoS Charge for each Settlement Period ($BSUoSINT_{jd}$)

9.14 The Internal BSUoS Charges ($BSUoSINT_{jd}$) for each Settlement Period j for a particular day are calculated by taking the incentivised and non-incentivised SO Internal Costs for each Settlement Day allocated on a MWh basis across each Settlement Period in a day.

$$BSUoSINT_{jd} = (CSOC_d + SOBR_d + NSOC_d + PSC_d + IncpayINT_d)$$
$$* \{ \left|\sum^{+}(QM_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QM_{ijd} * TLM_{ijd})\right| \} / \sum_{j \in d} \{ \left|\sum^{+}(QM_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QM_{ijd} * TLM_{ijd})\right| \}$$

9.15 Table 9.2 below summarises the annual SO Internal costs variables for Financial Year 2004/05. These are in 2001/2 forecast prices, as set out in the Transmission Licence.

Table 9.2

Internal SO Cost Variable	Annual Cost (£)
CSOC	57,567,216
SOBR	1,000,000
NSOC	20,120,580
PSC	0

Calculation of the daily Internal Incentive Payment ($IncpayINT_d$)

9.16 In respect of each Settlement Day d, $IncpayINT_d$ is calculated as the difference between the overall total incentive payment ($FKIncpayINT_d$) due to that date and the overall incentive payment made up to the previous day ($\xi_{k=0\equiv d-1} IncpayINT_k$) plus the daily cost of Manifest Errors and Special Provisions:

$$IncpayINT_d = \left(FKIncpayINT_d - \sum_{k=0}^{d-1} IncpayINT_k \right) + MESP_d$$

9.17 The forecast incentive payment made to date (from the commencement of the scheme) ($FKIncpayINT_d$) is calculated as the ratio of total forecast internal incentive payment across the duration of the scheme (FYIncpayINT): the number of days in the scheme, multiplied by the sum of the profiling factors to date.

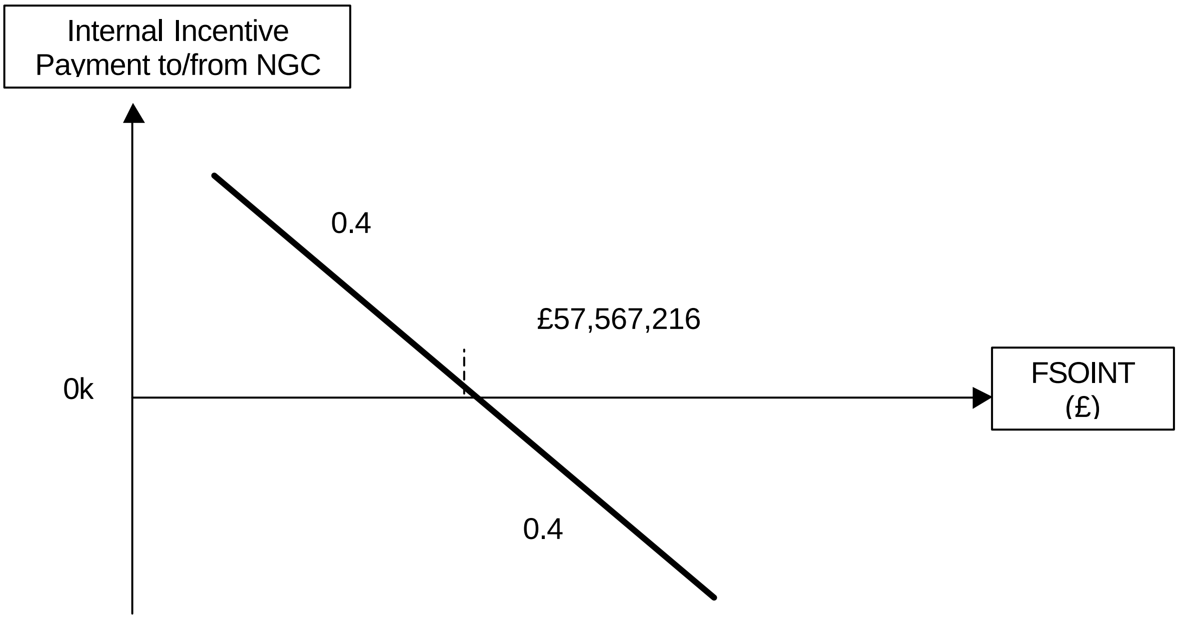
$$FKIncpayINT_d = \frac{FYIncpayINT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

9.18 National Grid daily Internal incentive payments ($IncPayINT_d$) are calculated by comparing the Daily Incentivised internal Costs ($FSOINT_d$) against the Daily Internal Scheme Target (PTint) to set the Sharing Factor (SFint). Table 9.3 shows the respective values of these variables.

$$FYIncPayINT_d = (PT\text{int} - FSOINT_d) * SF\text{int}$$

Table 9.3

$FSOINT_d$	**PTint**	**SFint**
$FSOINT_d$ < £57,567,216	£57,567,216	0.4
$FSOINT_d$ => £57,567,216	£57,567,216	0.4



9.19 In respect of each Settlement Day d, the forecast incentivised internal controllable System Operator cost ($FSOINT_d$) will be calculated as follows:

$$FSOINT_d = \frac{\sum_{k=1}^{d} CSOC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS: Number of days in Scheme.

Inclusion of Profiling Factors

9.20 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from National Grid according to the time of year. For the initial schemes, the profiling factors will be set to one.

Manifest Errors and Special Provisions for IT system failures

9.21 National Grid may, in certain circumstances, be required to pay compensation to BSC Parties as a result either of Manifest Errors or Special Provisions (collectively referred to as Contingency Provisions). For the avoidance of doubt charges for calling a manifest error are excluded.

9.22 An incentivised cost-recovery mechanism for such costs has been included within the internal System Operator BSUoS charge element. This cost-recovery mechanism operates on a monthly basis and provides that National Grid is exposed to 40% of any Contingency Provision costs invoiced to it in any month, subject to an overall monthly cap on its exposure of £250,000*.

9.23 Thus, if the Contingency Provision costs incurred exceed £625,000* (£250,000*/0.4) in any month, National Grid will be allowed to recover 60% of the costs it incurs up to £625,000*, and all the costs in excess of £625,000*. If costs are less than £625,000* then National Grid will recover 60% of these costs.

9.24 National Grid will calculate any allowable revenue associated with Contingency Provisions based on the invoices received in any particular month. The monthly revenue will then be recovered equally over the days in the following month. An invoice for the final month of the incentive scheme will be recovered in via the following incentive scheme in the next Financial Year.

9.25 The monthly cost associated with Manifest Errors and Special Provisions (CP_m) are subject to a monthly incentivised cost recovery mechanism based on a monthly Contingency Provision sharing factor (CSF_m) and an offset for Contingency Provisions (OS_m). The daily cost ($MESP_d$) is calculated as follows:

$$MESP_d = \frac{(1 - CSF_m)(CP_m - OS_m)}{NDM}$$

NDM = Number of Settlement Days in the calendar month over which these costs are recovered.

The values for the 2004/05 scheme, in 2001/02 forecast prices as given in the Transmission Licence, are shown in the table below.

Table 9.4

CP_m	CSF_m	OS_m
0 Ω CP_m < £625,000	0.4	£0
CP_m Δ £625,000	0	£250,000

* Subject to the indexation provisions given in the Transmission Licence

Chapter 10: Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

10.1 There are three stages of the reconciliation of BSUoS charges described below:

- Initial Settlement
- End of Scheme Year Reconciliation
- Final Reconciliation

Initial Settlement of BSUoS

10.2 National Grid will calculate initial settlement BSUoS charges in accordance with the methodology set out in Chapter 9 using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

10.3 The End of Scheme Year Reconciliation will be performed after the completion of Initial Settlement for all days in the scheme year, and prior to the commencement of Final Reconciliation. Charges for each settlement day will be recalculated in accordance with the methodology set out in Chapter 9, using the latest information available to National Grid at the time (with the inclusion of interest as defined in the CUSC). These revised daily charges will form the basis of a single reconciled charge aggregated over all settlement days in the scheme year.

10.3

10.4 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. National Grid will calculate Final Reconciliation BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in Chapter 9 using the latest available data, including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

10.5 If any of the elements required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to National Grid in time for it to do the calculations then National Grid will use data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to National Grid then National Grid will substitute such variables as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual data becomes available a reconciliation run will be undertaken.

Disputes

10.6 If National Grid or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then National Grid will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between The Statement of the Use of System Charging Methodology and the Transmission Licence

10.7 BSUoS charges are made on a daily basis and as such of this Statement sets out the details of the calculation of such charges on a daily basis. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that National Grid may recover in respect of the Balancing Services Activity.

10.8 National Grid has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
Balancing service contract costs – non-Settlement Period specific	$BSCCA_d$	£	Non Settlement Period specific Balancing Contract Costs for settlement day d
Balancing Service Contract Cost	$BSCC_j$	£	Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j
Balancing service contract costs – Settlement Period specific	$BSCCV_{jd}$	£	Settlement Period j specific Balancing Contract Costs for settlement day d
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
Total Balancing Services Use of System charge	$BSUoSTOT_j$	£	Total Balancing Services Use of System Charge applicable for Settlement Period j
System Operator BM Cash Flow	$CSOBM_j$	£	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001
Forecast incentivised internal controllable System Operator cost	CSOC	£	As defined in the Transmission Licence
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part 2 of Condition 4F of the Transmission Licence

EXPRESSION	**ACRONYM**	**Unit**	**Definition**
Forecast incentivised Balancing Cost	FBC_d	£	Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d
External Incentive payment to date	$FKIncpayEXT_d$	£	Total External Incentive Payment to date up to and including settlement day d
Internal Incentive payment to date	$FKIncpayINT_d$	£	Total Internal Incentive Payment to date up to and including settlement day d
Forecast incentivised internal controllable System Operator cost	$FSOint_d$	£	Forecast incentivised internal controllable System Operator cost for the duration of the incentive scheme as at settlement day d
Total Forecast External incentive payment	$FYIncpayEXT_d$	£	Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d
Total Forecast Internal incentive payment	$FYIncpayINT_d$	£	Total forecast Internal incentive payment for the entire duration of the incentive scheme as at settlement day d
Daily Incentivised Balancing Cost	IBC_d	£	Is equal to that value calculated in accordance with paragraph 9.13 of Part 2 of this Statement
Daily External incentive payment	$IncpayEXT_d$	£	External Incentive payment for Settlement Day d
Daily Internal incentive payment	$IncpayINT_d$	£	Internal Incentive payment for Settlement Day d
Net Imbalance Volume Cost	NI_j	£	Total Net Energy Imbalance Volume ($TQEI_j$)*Net Imbalance Reference Price ($NIRP_j$)
Net Imbalance Reference Price	$NIRP_j$		As defined in the Transmission Licence
Non-controllable System Operator cost	NSOC	£	As defined in the Transmission Licence
Cost associated with the Provision of Balancing Services to others	OM_d	£	Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition 4F of the Transmission Licence
Incentivised Balancing Cost daily profiling factor	PFT_d		The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d
Costs associated with preparing participants systems for the	PSC	£	As defined in the Transmission Licence

EXPRESSION	ACRONYM	Unit	Definition
introduction of NETA			
Daily Internal Scheme Target	PTint	£	Target for the Internal Incentive scheme as agreed with Ofgem
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition 4F of the Transmission Licence
Internal Scheme sharing factor	SFint		Sharing Factor for the internal incentive scheme as agreed with Ofgem
Costs associated with the System Operator business rates	SOBR	£	As defined in the Transmission Licence
Transmission Losses Cost	TL_j	£	Total Volume of Transmission Losses (TLV_j)*Transmission Losses Reference Price ($TLRP_j$)
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Transmission Losses Reference Price	$TLRP_j$		As defined in the Transmission Licence
Transmission Losses Volume	TLV_j	MWh	$\xi_i QM_{ij}$ – Sum of BM Unit Metered Volume (QM_{ij}) over all BM units
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC

Appendix BS-1

Examples of Balancing Services Use of System (BSUoS) Daily Charge Calculations

This example illustrates the operation of the Balancing Services Use of System Daily charge formula. The parameters used are for illustrative purposes only and have been chosen for ease of calculation. They do not relate to the agreed scheme for any particular year. The actual scheme parameters are shown in the main text.

The example is divided into the calculation of the External System Operator cost and Internal System Operator cost elements. All daily profiling factors (PFT_d) have been assumed to be one for this example.

Day 1

Calculation of the Daily External SO Incentive Scheme Payment

The first step is to calculate the Daily Incentivised Balancing Cost (IBC_1 for day one) for that day using the following formula. These are the daily incentivised cost elements used to calculate the external SO incentive payment.

$$IBC_1 = CSOBM_1 + BSCCA_1 + BSCCV_1 + TL_1 + NI_1 - OM_1 - RT_1$$

$$= £800k + £300k + £200k + £300k - £50k - £0k - £0k$$

$$= £1550k$$

Assuming that	$CSOBM_1$	=	£800k
	$BSCCA_1$	=	£300k
	$BSCCV_1$	=	£200k
	TL_1	=	£300k
	NI_1	=	-£50k
	OM_1	=	£0k
	RT_1	=	£0k

Now that we know IBC_1, it is possible to calculate Forecast Balancing Services Cost (FBC_1) from that day's outturn as follows:

$$FBC_1 = \frac{\sum_{k=1}^{d=1} IBC_k}{\sum_{k=1}^{d=1} PFT_k} * NDS$$

$$= \frac{£1550k}{1} * 365$$

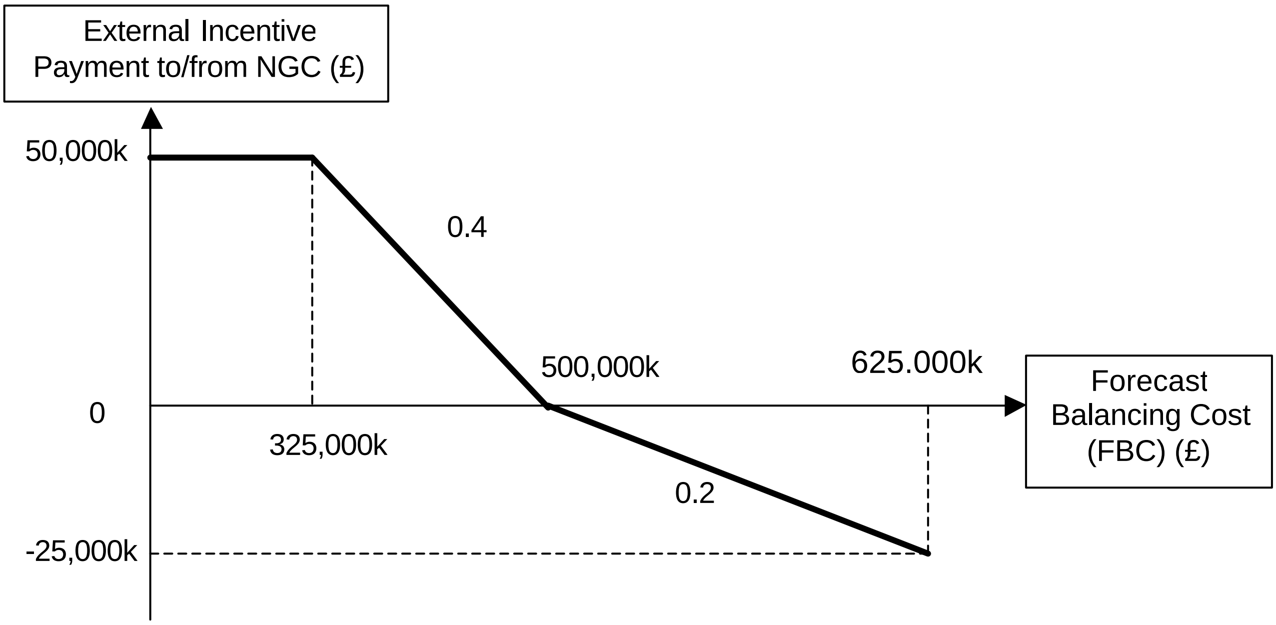
$$= £565,750k$$

The values of SFext and OSext can now be read off table BS1 below. (These values are used purely for illustrative purposes). As FBC_1 is £565,750k, SFext is 0.2, OSext is £0 and BPext is £500,000k.

Table BS1

Forecast Balancing Cost (FBC_d)	**BPext**	**SFext**	**OSext**
£325,000,000 ∆ FBC	£325,000,000	0	£50,000,000
£500,000,000 ∆ FBC > £325,000,000	£500,000,000	0.4	£0
£625,000,000 ∆ FBC > £500,000,000	£500,000,000	0.2	£0
FBC > £625,000,000	£625,000,000	0	£25,000,000

The table describes the external incentive scheme, which can also be illustrated by the graph below.



Using the values set out in the table above, the external SO incentive payment for the duration of the scheme (FYIncpayEXT) can be calculated as follows:

$$\begin{aligned} FYIncpayEXT_1 &= SFext * (BPext - FBC_1) + OSext \\ &= 0.2 * (£500{,}000k - £565{,}750k) + £0 \\ &= -£13{,}150k \end{aligned}$$

In this case the incentive payment is negative (-£13,150k) i.e. a payment from National Grid.

The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:

$$FKIncpayEXT_1 = \frac{FYIncpayEXT_1}{NDS} * \sum_{k=1}^{d=1} PFT_k$$
$$= \frac{-£13{,}150\,K}{365} * 1$$
$$= -£36{,}027$$

Where:

NDS = Number of days in the external incentive scheme

The final step is to calculate today's external incentive payment ($IncpayEXT_1$ for day one), shown as follows:

$$IncpayEXT_1 = FKIncpayEXT_1 - \sum_{k=0}^{d-1=0} IncpayEXT_k$$
$$= -£36{,}027 - £0$$
$$= -£36{,}027$$

Calculation of the Daily Internal SO Incentive Scheme Payment

To carry this out, National Grid will forecast monthly incentivised SO costs (CSOC) and profile them to a daily basis. For this illustration, monthly costs for the first month of the scheme (April in our example) are assumed to be **£4,500k,** profiled down to a daily forecast of **£150k** (£450,000k divided by 30).

The calculation of the forecast SO internal cost for day one ($FSOINT_1$) is shown as follows:

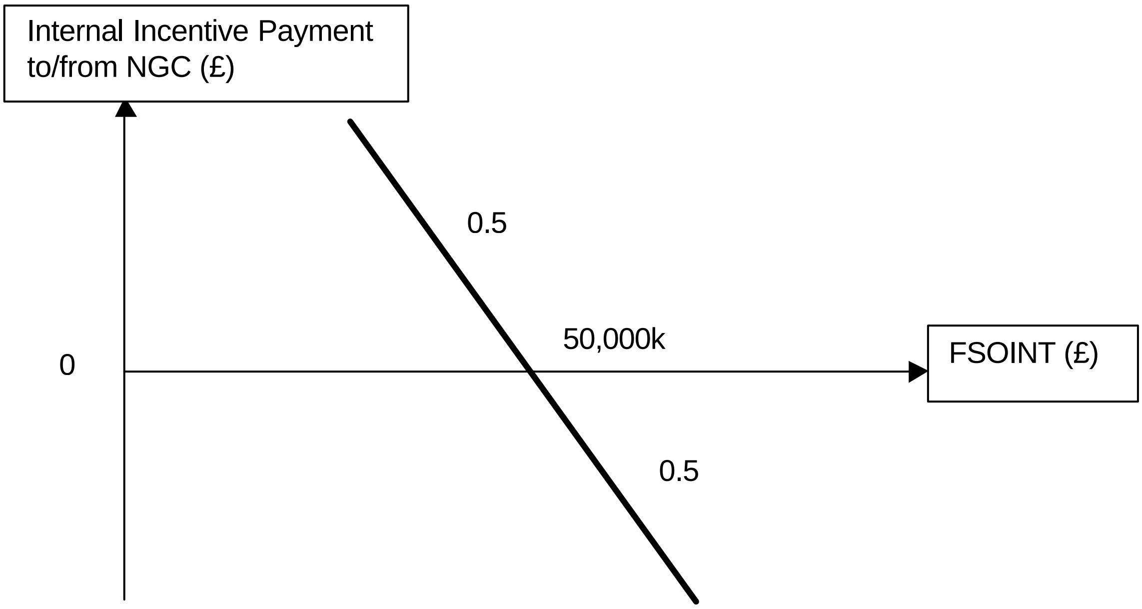
$$FSOINT_1 = \frac{\sum_{k=1}^{d=1} CSOC_k}{\sum_{k=1}^{d=1} PFT_k} * NDS$$
$$= \frac{£150\,k}{1} * 365$$
$$= £54{,}750\,k$$

The relevant value of the External incentive payment ($FYIncpayINT_1$) can then be calculated by reference to Table BS2 (figures shown for illustration only) and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast incentivised internal SO cost (FSOINT).

Table BS2

FSOINT	Ptint	SFint
FSOINT < £50,000k	£50,000k	0.5
FSOINT = £50,000k	£50,000k	0
FSOINT > £50,000k	£50,000k	0.5

The table describes the internal incentive scheme which can also be illustrated by the graph below.



Using the forecast internal cost for day one ($FSOINT_1$), the internal incentive payment for the duration of the scheme ($FYIncpayINT_1$) is calculated as follows:

$$FYIncPayINT_1 = (PT\text{int} - FSOINT_1) * SF\text{int}$$
$$= (£50{,}000k - £54{,}750k) * 0.5$$
$$= -£2{,}375k$$

The forecast internal SO incentive payment for the duration of the scheme ($FYIncpayINT_1$) can then be used to calculate the forecast incentive payment to date ($FKIncpayINT_1$), shown as follows:

$$FKIncpayINT_1 = \frac{FYIncpayINT_1}{NDS} * \sum_{k=1}^{d=1} PFT_k$$
$$= \frac{-£2{,}375k}{365} * 1$$
$$= -£6{,}507$$

The final step is to calculate the Internal incentive payment ($IncpayINT_1$ for day one):

$$IncpayINT_1 = (FKIncpayINT_1 - \sum_{k=0}^{d-1=0} IncpayINT_k) + MESP_1$$
$$= (£6{,}507 - £0) + £0$$
$$= -£6{,}507$$

The costs associated with Manifest Errors and Special Provisions for day 1 ($MESP_1$) are assumed to be zero.

Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j

The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 on this Settlement Day 1 can now be calculated using the following formula:

$$BSUoSEXT_{11} = CSOBM_{11} + BSCCV_{11} + [\ (IncpayEXT_1 + BSCCA_1 + ET_1 - OM_1) * \{ \left|\sum^{+}(QM_{i11} * TLM_{i11})\right| + \left|\sum^{-}(QM_{i11} * TLM_{i11})\right| \} / \sum_{j \in 1} \{ \left|\sum^{+}(QM_{ij1} * TLM_{ij1})\right| + \left|\sum^{-}(QM_{ij1} * TLM_{ij1})\right| \}\ ]$$

For simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48) i.e. the multiplier at the end of the equation.

The illustration below shows the external BSUoS charge ($BSUoSEXT_{11}$) for Settlement Period one of Settlement Day 1.

The costs of the external SO Settlement Period variables are as follows (these are the daily values included in the IBC_1 equation divided by 48 Settlement Periods).

CSOBM = £16,667
BSCCV = £4,167

The costs of the external SO Settlement Day variables are as follows:

IncpayEXT = £-36,027
BSCCA = £300k
ET = £0k
OM = £0k

$$\begin{aligned} BSUoSEXT_{11} &= £16{,}667 + £4{,}167 + [\ (-£36{,}027 + £300k + £0k - £0k)/48\ ] \\ &= £16{,}667 + £4{,}167 + £5{,}499 \\ &= £26{,}333 \end{aligned}$$

Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j

The Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period 1 of Settlement Day 1 can now be calculated using the following formula:

$$BSUoSINT_{11} = (CSOC_1 + SOBR_1 + NSOC_1 + PSC_1 + IncpayINT_1) * \{ \left|\sum^{+}(QM_{i11} * TLM_{i11})\right| + \left|\sum^{-}(QM_{i11} * TLM_{i11})\right| \} / \sum_{j \in 1} \{ \left|\sum^{+}(QM_{ij1} * TLM_{ij1})\right| + \left|\sum^{-}(QM_{ij1} * TLM_{ij1})\right| \}$$

As with the external BSUoS charge, for simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48).

Table BS3 below shows the annual Internal SO costs assumed for this example:

Table BS3

Internal SO Cost Variable	Annual Cost (£m)
CSOC	50
SOBR	5
NSOC	30
PSC	1

If we assume that the incentivised internal SO costs (CSOC) are £150k for day 1 and the other cost pass through and non-incentivised elements are recovered uniformly across the year (i.e. 1/365) then:

- CSOC (incentivised Internal SO costs) = £150k
- SOBR (Pass Through costs) = £13,699
- NSOC (Non incentivised costs) = £82,192
- PSC (Pass Through costs) = £2,740

$$BSUoSINT_{11} = (£150k + £13{,}699 + £82{,}192 + £2{,}740 + -£6{,}507)/48$$
$$= £5{,}044$$

<u>Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period 1</u>

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{11}$) for a Settlement Period 1 on Settlement Day 1.

$$BSUoSTOT_{11} = BSUoSEXT_{11} + BSUoSINT_{11}$$
$$= £26{,}333 + £5{,}044$$
$$= £31{,}377$$

Day 2

Calculation of the Daily External SO Incentive Scheme Payment

Again, the first step is to calculate the Daily Incentivised Balancing Cost for day 2 (IBC_2) using the following formula:

$$IBC_2 = CSOBM_2 + BSCCA_2 + BSCCV_2 + TL_2 + NI_2 - OM_2 - RT_2$$

$$= £600k + £150k + £100k + £200k - £100k - £0 - £0$$

$$= £950k$$

Assuming that	$CSOBM_2$	=	£600k
	$BSCCA_2$	=	£150k
	$BSCCV_2$	=	£100k
	TL_2	=	£200k
	NI_2	=	-£100k
	OM_2	=	£0k
	RT_2	=	£0k

With IBC_d known for day one, it is possible to calculate Forecast Balancing Services Cost (FBC_2) from the outturn to date as follows:

$$FBC_2 = \frac{\sum_{k=1}^{d=2} IBC_k}{\sum_{k=1}^{d=2} PFT_k} * NDS$$

$$= \frac{(£1550k + £950k)}{2} * 365$$

$$= £456,250k$$

The values of SFext, BPext and OSext can now be read off table BS1 given previously. As FBC_2 is £456,250k, SFext is now 0.4, BPext is £500,000k and OSext is 0, calculated as follows:

$$FYIncpayEXT_2 = SFext * (BPext - FBC_2) + OSext$$

$$= 0.4 * (£500,000k - £456,250k) + £0$$

$$= £17,500k$$

The external SO incentive payment for the entire duration of the incentive scheme ($FYincpayEXT_2$) is then used to calculate the total incentive payment to date ($FKIncpayEXT_2$), shown as follows:

$$FKIncpayEXT_2 = \frac{FYIncpayEXT_2}{NDS} * \sum_{k=1}^{d=2} PFT_k$$
$$= \frac{£17,500k}{365} * 2$$
$$= £95,890$$

Where:

NDS = Number of days in the external incentive scheme

In this case the incentive payment is £95,890.

Again, the final step is to calculate today's external incentive payment ($IncpayEXT_2$ for day two), shown as follows:

$$IncpayEXT_2 = FKIncpayEXT_2 - \sum_{k=0}^{d-1=1} IncpayEXT_k$$
$$= £95,890 - -£36,027$$
$$= £131,917$$

Calculation of the Daily Internal SO Incentive Scheme Payment

The first step is to calculate the forecast SO internal cost for day two ($FSOINT_2$). The same forecast of **£150k** for daily incentivised SO costs (CSOC) used for day one is used for day two.

The calculation of the forecast SO internal cost ($FSOINT_2$) is shown as follows:

$$FSOINT_2 = \frac{\sum_{k=1}^{d=2} CSOC_k}{\sum_{k=1}^{d=2} PFT_k} * NDS$$
$$= \frac{(£150,000 + £150,000)}{2} * 365$$
$$= £54,750k$$

Using the forecast SO internal cost ($FSOINT_2$), the forecast internal SO incentive payment for the duration of the scheme ($FYIncpayINT_2$) can be calculated as follows (with reference to the values in Table BS2).

$$FYIncPayINT_2 = (PT\text{int} - FSOINT_2) * SF\text{int}$$
$$= (£50,000k - £54,750k) * 0.5$$
$$= -£2,375k$$

The forecast internal SO incentive payment for the duration of the scheme ($FYIncpayINT_2$) can then be used to calculate the forecast incentive payment to date ($FKIncpayINT_2$), shown as follows:

$$FKIncpayINT_2 = \frac{FYIncpayINT_2}{NDS} * \sum_{k=1}^{d=2} PFT_k$$
$$= \frac{-£2{,}375k}{365} * 2$$
$$= -£13{,}014$$

The final step is to calculate the Internal incentive payment ($IncpayINT_2$ for day two).

$$IncpayINT_2 = (FKIncpayINT_2 - \sum_{k=0}^{d-1=1} IncpayINT_k) + MESP_2$$
$$= (-£13{,}014 - -£6{,}507) + £0$$
$$= -£6{,}507$$

The costs associated with Manifest Errors and Special Provisions for day 2 ($MESP_2$) are assumed to be zero.

As all of the internal cost variables are the same on day 1 as on day 2 the incentive payments for each of these days are identical.

<u>Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j</u>

The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 of Settlement Day 2 can now be calculated using the following formula:

$$BSUoSEXT_{12} = CSOBM_{12} + BSCCV_{12} + [\ (IncpayEXT_2 + BSCCA_2 + ET_2 - OM_2)$$
$$* \{\ \left|\sum{}^{+}(QM_{i12} * TLM_{i12})\right| + \left|\sum{}^{-}(QM_{i12} * TLM_{i12})\right|\ \} / \sum_{j\in 2} \{\ \left|\sum{}^{+}(QM_{ij2} * TLM_{ij2})\right| + \left|\sum{}^{-}(QM_{ij2} * TLM_{ij2})\right|\ \}\ ]$$

As with day one, for simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48).

The costs of the external SO Settlement Period variables are as follows:

CSOBM = £12,500
BSCCV = £2,083

The costs of the external SO Settlement Day variables are as follows:

IncpayEXT = £131,917
BSCCA = £150k
ET = £0k
OM = £0k

$$BSUoSEXT_{12} = £12{,}500 + £2{,}083 + [\ (£131{,}917 + £150k + £0k - £0k)/48\ ]$$
$$= £12{,}500 + £2{,}083 + £5{,}873$$
$$= £20{,}456$$

Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j

The Internal Balancing Services Use of System (BSUoS) charge for Settlement Period 1 on Settlement Day 2 can now be calculated using the following formula:

$$BSUoSINT_{12} = (CSOC_2 + SOBR_2 + NSOC_2 + PSC_2 + IncpayINT_2)$$
$$*\{ \left|\sum{}^{+}(QM_{i12} * TLM_{i12})\right| + \left|\sum{}^{-}(QM_{i12} * TLM_{i12})\right| \} / \sum_{j\in 2} \{ \left|\sum{}^{+}(QM_{ij2} * TLM_{ij2})\right| + \left|\sum{}^{-}(QM_{ij2} * TLM_{ij2})\right| \}$$

As with the external BSUoS charge, for simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day (1/48).

The Settlement Day 2 costs of the internal SO cost variables assigned to Settlement period 1 (based on values from Table BS3) are as follows:

$$BSUoSINT_{12} = (£150k + £13{,}699 + £82{,}192 + £2{,}740 + -£6{,}507)/48$$
$$= £5{,}044$$

Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period j

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{12}$) for Settlement Period 1 on Settlement Day 2.

$$BSUoSTOT_{12} = BSUoSEXT_{12} + BSUoSINT_{12}$$
$$= £20{,}456 + £5{,}044$$
$$= £25{,}500$$

Day 365

If we now move to the end of the year, then once again the first step is to calculate the Daily Incentivised Balancing Cost for the final day (IBC_{365}) using the formula below:

Calculation of the Daily External SO Incentive Scheme Payment

$$IBC_{365} = CSOBM_{365} + BSCCA_{365} + BSCCV_{365} + TL_{365} + NI_{365} - OM_{365} - RT_{365}$$

$$= £700k + £\ 200k + £150k + £200k - £50k - £0 - £0$$

$$= £1{,}200k$$

Assuming that	$CSOBM_{365}$	=	£700k
	$BSCCA_{365}$	=	£200k
	$BSCCV_{365}$	=	£150k
	TL_{365}	=	£200k
	NI_{365}	=	-£50k
	OM_{365}	=	£0k
	RT_{365}	=	£0k

With ? $_{364}IBC_d$ assumed to be £432,000k for the previous 364 days, it is possible to calculate Forecast Balancing Services Cost (FBC_{365}) from the outturn to date as follows:

$$FBC_{365} = \frac{\sum_{k=1}^{d=365} IBC_k}{\sum_{k=1}^{d=365} PFT_k} * NDS$$

$$= \frac{£432{,}000k + £1{,}200k}{365} * 365$$

$$= £433{,}200k$$

The values of SFext, BPext and OSext can now be read off table BS1. As FBC_{365} is £433,200k, SFext is now 0.4, BPext is £500,000k and OSext is 0. Therefore $FYIncpayEXT_{365}$ is calculated as follows:

$$FYIncpayEXT_{365} = SFext * (BPext - FBC_{365}) + OSext$$

$$= 0.4 * (£500{,}000k - £433{,}200k) + £0$$

$$= £26{,}720k$$

The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculated the total incentive payment to date (FKIncpayEXT), shown as follows:

$$FKIncpayEXT_{365} = \frac{FYIncpayEXT_{365}}{NDS} * \sum_{k=1}^{d=365} PFT_k$$
$$= \frac{£26{,}720k}{365} * 365$$
$$= £26{,}720k$$

Where:

NDS = Number of days in the external incentive scheme

In this case the incentive payment is positive (£26,720k) i.e. a payment to National Grid. As this is the last day of the scheme this represents the overall incentive payment due to National Grid i.e. with reference to the graph with Table BS1 40% of the difference between £500,000k and £433,200k.

Again, the final step is to calculate today's external incentive payment ($IncpayEXT_{365}$ for day 365), shown as follows:

It has been assumed that the total incentive payments for the previous 364 days ($\xi_{k=0\equiv364}IncpayEXT_k$) is £26,237,400.

$$IncpayEXT_{365} = FKIncpayEXT_{365} - \sum_{k=0}^{d-1=364} IncpayEXT_k$$
$$= £26{,}720{,}000 - £26{,}237{,}400$$
$$= £482{,}600$$

Calculation of the Daily Internal BSUoS Charge

Again, the first step is to calculate the forecast SO internal cost for day 365 ($FSOINT_{365}$).

To carry this out, National Grid will forecast monthly incentivised SO costs (CSOC) and profile them to a daily basis. For this illustration, monthly costs for the final month of the scheme (March in our example) are assumed to be **£4,000k,** profiled down to a daily forecast of **£129,032** (£4,000k divided by 31).

If $FSOINT_{364}$ is assumed to be £52,000k, the calculation of the forecast SO internal cost ($FSOINT_{365}$) is shown as follows:

$$FSOINT_{365} = \frac{\sum_{k=1}^{d=365} CSOC_k}{\sum_{k=1}^{d=365} PFT_k} * NDS$$
$$= \frac{£52{,}000k + £129{,}032}{365} * 365$$
$$= £52{,}129{,}032$$

Using the forecast SO internal cost ($FSOINT_{365}$), the forecast internal SO incentive payment for the duration of the scheme ($FYIncpayINT_{365}$) can be calculated as follows:

$$FYIncPayINT_{365} = (PT\text{int} - FSOINT_{365}) * SF\text{int}$$
$$= (£50{,}000{,}000 - £52{,}129{,}032) * 0.5$$
$$= -£1{,}064{,}516$$

The forecast internal SO incentive payment for the duration of the scheme ($FYIncpayINT_{365}$) can then be used to calculate the forecast incentive payment to date ($FKIncpayINT_{365}$), shown as follows:

$$FKIncpayINT_{365} = \frac{FYIncpayINT_{365}}{NDS} * \sum_{k=1}^{d=365} PFT_k$$
$$= \frac{-£1{,}064{,}516}{365} * 365$$
$$= -£1{,}064{,}516$$

In this case the incentive payment is negative (-£1,065k) i.e. a payment from National Grid. As this is the last day of the scheme this represents the overall incentive payment due from National Grid i.e. with reference to the graph with Table BS2 50% of the difference between £50,000k and £52,129k.

The final step is to calculate the Internal incentive payment ($IncpayINT_{365}$ for day 365). It has been assumed that the total incentive payments for the previous 364 days ($\xi_{k=0\equiv 364} IncpayINT_k$) is £1,056,145.

$$IncpayINT_{365} = (FKIncpayINT_{365} - \sum_{k=1}^{d-1=364} IncpayINT_k) + MESP_{365}$$
$$= (-£1{,}064{,}516 - -£1{,}056{,}145) + £0$$
$$= -£8{,}371$$

The costs associated with Manifest Errors and Special Provisions for day 365 ($MESP_{365}$) are assumed to be zero.

<u>Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j</u>

The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 of Settlement Day 365 can now be calculated using the following formula:

$$BSUoSEXT_{1365} = CSOBM_{1365} + BSCCV_{1365} + [\,(IncpayEXT_{365} + BSCCA_{365} + ET_{365} - OM_{365})$$
$$* \{ \left|\sum{}^{+}(QM_{i1365} * TLM_{i1365})\right| + \left|\sum{}^{-}(QM_{i1365} * TLM_{i1365})\right| \} / \sum_{j\in 365} \{ \left|\sum{}^{+}(QM_{ij365} * TLM_{ij365})\right| + \left|\sum{}^{-}(QM_{ij365} * TLM_{ij365})\right| \}$$

As with day one, for simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day (1/48).

The costs of the external SO Settlement Period variables are as follows:

CSOBM = £14,583
BSCCV = £3,125

The costs of the external SO Settlement Day variables are as follows:

IncpayEXT = £482,600
BSCCA = £200k
ET = £0k
OM = £0k

$$\begin{aligned} BSUoSEXT_{365} &= £14{,}583 + £3{,}125 + [\ (£482{,}600 + £200k + £0k - £0k\ )/48\ ] \\ &= £14{,}583 + £3{,}125 + £14{,}221 \\ &= £31{,}929 \end{aligned}$$

<u>Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j</u>

The Internal Balancing Services Use of System (BSUoS) charge for Settlement Period 1 of Settlement Day 365 can now be calculated using the following formula:

$$\begin{aligned} &BSUoSINT_{1365} = (CSOC_{365} + SOBR_{365} + NSOC_{365} + PSC_{365} + IncpayINT_{365}) \\ &* \{ \left|\sum^{+}(QM_{i1365} * TLM_{i1365})\right| + \left|\sum^{-}(QM_{i1365} * TLM_{i1365})\right| \} / \sum_{j\in 365} \{ \left|\sum^{+}(QM_{ij365} * TLM_{ij365})\right| + \left|\sum^{-}(QM_{ij365} * TLM_{ij365})\right| \} \end{aligned}$$

As with the external BSUoS charge, for simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day (1/48).

The Settlement Day 365 costs of the internal SO cost variables assigned to Settlement Period 1 (based on values from Table BS3) are as follows:

$$\begin{aligned} BSUoSINT_{1365} &= (£129{,}032 + £13{,}699 + £82{,}192 + £2{,}740 + -£8{,}371)/48 \\ &= £4{,}569 \end{aligned}$$

<u>Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period j</u>

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{1365}$) for Settlement Period 1 on Settlement Day 365

$$\begin{aligned} BSUoSTOT_{1365} &= BSUoSEXT_{1365} + BSUoSINT_{1365} \\ &= £31{,}929 + £4{,}569 \\ &= £36{,}498 \end{aligned}$$

Glossary

The following definitions are intended to assist the reader's understanding of this document. In the event of conflict with definitions given elsewhere, those used in the Electricity Act 1989 (as amended by the Utilities Act 2000), Transmission Licence, Grid Code, Balancing and Settlement Code and Connection and Use of System Code take precedence.

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

10 Clear Days	Defined as 10 complete periods of 24 hours from 00:00hrs to 24:00hrs
Act	the Electricity Act 1989
Additional Load	Site Load other than Station Load and importing Generating Units for processes other than the production of electricity
Ancillary Services	Has the meaning given to that expression in the Transmission Licence
Applicable Value	The highest contractual Transmission Entry Capacity figure for year "t" provided to National Grid in line with the process laid out in the CUSC up to and including 31 October in year "t-1" for publication in the October update of the Seven Year Statement
Authority	The Gas and Electricity Markets Authority (Ofgem)
Balancing and Settlement Code (BSC)	As defined in the Transmission Licence
Balancing Mechanism	As defined in the Transmission Licence
Bid	Defined in the BSC as: "The quantity (as provided in Section Q4.1.3(a)) in a Bid-Offer Pair if considered as a possible decrease in Export or increase in Import of the relevant BM Unit at given time"
Bilateral Agreement	Means, in relation to a User, a Bilateral Connection Agreement or a Bilateral Embedded Generation Agreement between National Grid and the User, as defined in Standard Condition 1 of the National Grid Transmission Licence
BM Unit	Defined in the BSC as: "a unit established and registered (or to be established and registered) by a Party in accordance with section K3 [of the BSC]"

BM Unit Metered Volume "QM_{ij}"	Defined in the BSC as: "In respect of a Settlement Period: (i) in relation to a BM Unit (other than an Interconnector BM Unit) comprising CVA Metering Systems, the Metered Volume (as determined in accordance with Section R [of the BSC]); (ii) in relation to an Interconnector BM Unit, the quantity determined in accordance with Section R7.4.2 [of the BSC]; (iii) in relation to an Interconnector Error Administrator BM Unit, the quantity determined in accordance with Section T4.1;and (iv) in relation to a Supplier BM Unit, the quantity determined in accordance with section T4.2.1 [of the BSC]."
Central Volume Allocation	Defined in the BSC as: "the determination of quantities of Active Energy to be taken into account for the purposes of Settlement in respect of Volume Allocation Units"
Consumption	Defined in the BSC in relation to a Consumption BM Unit as: "means a BM Unit which: i.) in the case of a BM Unit other than an Interconnector BM Unit, is classified as a Consumption BM Unit in accordance with the provisions of Section K 3.5.2 [of the BSC] or in the case of an Exempt Export BM Unit, the Lead Party has elected to treat as a Consumption BM Unit pursuant to Section K 3.5.5 [of the BSC] ii.) In the case of an Interconnector BM Unit, is designated by the CRA as a 'Consumption' BM Unit pursuant to Section K 5.5.5 [of the BSC]"
DCLF	Direct Current Loadflow
Delivering	As defined in the BSC
Demand	Electricity consumed at sites or by equipment not owned and operated by National Grid
Directly-connected User	A large, usually industrial, consumer of electricity who is directly connected to National Grid's transmission system
Distribution Interconnector	Defined in the BSC as: "An Interconnector whose connection to the Total System is only to a Distribution System"
Distribution System	As defined in the BSC:
Distribution voltage	A voltage of 132kV or below. Generally taken to be voltages lower than those defined as transmission voltages

Embedded	Direct connection to a distribution system or the system of any other User to which Users and /or Power Stations are connected
Exempt Export BM Unit	Defined in the BSC as: "A BM Unit which comprises Exemptable Generating Plant, for which the Lead Party is the Party responsible for Exports, subject to Section K3.3A;"
Exempt generator	Any generator who, under the terms of the Electricity (Class Exemptions from the Requirement for a Licence) Order 2001, is not obliged to hold a generation licence
Export	Defined in the BSC as: "in relation to a party, a flow of electricity from any Plant or apparatus (not comprising of the Total System) of that party to the Plant or apparatus (comprising part of the Total System) of a party."
Final Reconciliation Settlement Run	Defined in the BSC as: "the last required Timetabled Reconciliation Settlement Run"
Final Reconciliation Volume Allocation Run	Defined in the BSC as: "the last required Timetabled Reconciliation Volume Allocation Run"
Financial Year	The period of 12 months ending on 31st March in each calendar year
Generating Unit	As defined in the Grid Code
Generation Capacity	Defined in the BSC as: normal full load capacity of a Generating Unit as declared by the Generator, less the MW consumed by the Generating Unit through the Generating Unit's unit transformer when producing the same
Generator	A person who generates electricity under licence or exemption under the Act
Genset	Is used to have the same meaning as Generating Unit as defined by the Grid Code
Good industry practice	In relation to any undertaking and any circumstances, the exercise of that degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced operator in the same type of undertaking under the same or similar circumstances

Grid Code	A document prepared by National Grid in accordance with Condition 7 of the Transmission Licence setting out the technical parameters for the operation and use of the transmission system and of plant and apparatus connected to the transmission system
Grid Supply Point (GSP)	A point of delivery from the National Grid Transmission System to a distribution system or Non-Embedded User
GSP Group	Is used to have the same meaning as in the BSC
Import	Defined in the BSC as: "in relation to a party, a flow of electricity to any Plant or Apparatus (not comprising part of the Total System) of that Party from the Plant or Apparatus (comprising part of the Total System) of a Party."
Income Adjusting Event	Has the meaning given to that expression in the Transmission Licence
Initial Settlement Run	Is used to have the same meaning as in the BSC
Initial Volume Allocation Run	As defined in the BSC
Interconnector	As defined in the BSC
Interconnector Asset Owner	The owner of the Interconnector
ICRP	Investment Cost Related Pricing
Less than 100MW	Is defined as not having the capability to export 100MW to the Total System
Licence standards	Standards listed in Special Condition AA2 of the Transmission Licence or otherwise registered with the Authority in accordance with which National Grid is required to plan, develop, operate and maintain the transmission system
Licensable Generation	Generating plant where the party generating electricity at that generating plant is required to hold a Generation Licence
Natural Demand	The Demand (active power) which is necessary to meet the needs of customers excluding that Demand (active power) met by embedded generating units whose generation is not traded by trading parties through energy metering systems registered under the BSC
Net Demand	Sum of the BM Unit Metered Volumes (QM_{ij}) of the Trading Unit during the three Settlement Periods of the Triad expressed as a positive number (i.e. ?QM_{ij}.)

National Grid Transmission System	The system consisting (wholly or mainly) of high voltage electric lines owned or operated by National Grid and used for the transmission of electricity from one Power Station to a substation or to another Power Station or between substations or to or from any External Interconnection and includes any Plant and Apparatus and meters owned or operated by National Grid in connection with the transmission of electricity but does not include any Remote Transmission Assets
Non-embedded User	A User, except an Electricity Distributor, receiving electricity direct from the National Grid Transmission System irrespective of from whom it is supplied
Offer	Defined in the BSC as: "The quantity (as provided in Section Q4.1.3 (a)) in a Bid-Offer pair if considered as a possible increase in Export or decrease in Import of the relevant BM Unit at a given time"
Offtaking	As defined in the BSC
Ownership boundary	Shall be the boundary defined by Clause 2.12 of the Connection and Use of System Code
Power Station	Defined in the Grid Code as: "an installation comprising one or more Generating Units (even where sited separately) owned and/or controlled by the same Generator, which may be reasonably considered as being managed as one Power Station."
Production	Defined in the BSC in relation to a Production BM Unit as: "means a BM Unit which: i.) In the case of a BM Unit other than an interconnector BM Unit, is classified as a Production BM Unit in accordance with the provisions of Section K 3.5.2 [of the BSC] or in the case of an Exempt Export BM Unit, the Lead Party has elected to treat as a Production BM Unit pursuant to Section K 3.5.5 [of the BSC] ii.) In the case of an Interconnector BM Unit, is designated by the CRA as a 'Production' BM Unit pursuant to Section K 5.5.5 [of the BSC]"
Reconciliation Settlement Run	Defined in the BSC as: "A Timetabled Reconciliation Settlement Run or an Ad Hoc Settlement Run"
Registered Capacity	As defined in the Grid Code
Security Standard	National Grid Transmission System Security and Quality of Supply Standard

Settlement Administration Agent (SAA)	Defined in the BSC as: “the BSC Agent for Settlement Administration in accordance with Section E [of the BSC].”
Settlement Day	has the meaning given to that expression in the BSC
Settlement Period	Defined in the BSC as: “Settlement Period j starts at the spot time occurring at the beginning of the half hour and ends at the spot time occurring exactly 30 minutes later. The spot time at the beginning of one period therefore coincides with the spot time at the end of the previous period.”
Settlement Run	Defined in the BSC as: “a determination (in accordance with Section T), in relation to a Settlement Day, of amounts giving rise, on the part of Trading Parties and the Transmission Company, to a liability to pay or a right to be paid by the BSC Clearer amounts in respect of Trading Charges in each Settlement Period in that Settlement Day, and of the net credit or debit in respect of such amounts; and where the context requires a reference to a Settlement Run includes the data and information produced by the SAA following such a determination and delivered to the FAA in accordance with Section N”
Short Term Transmission Entry Capacity (STTEC)	As defined in the Connection and Use of System Code
STTEC Period	As defined in the Connection and Use of System Code
STTEC Charge	The product of the STTEC and the STTEC tariff calculated in accordance with Paragraph 3.3 and 3.5 of The Statement of Use of System Charging Methodology
Site Load	May comprise Station Load and Additional Load. The sum of the BM Unit Metered Volumes (QM_{ij}), expressed as a positive number, of BM Units within the Trading Unit with QM_{ij} less than zero during the three Settlement Periods of the Triad (i.e. ?QM_{ij} where QM_{ij}<0)
Small Power Station	Defined in the Grid Code as: “A Power Station with a Registered Capacity of less than 50MW.”
Sole Trading Unit	Defined in the BSC as: “a Trading Unit comprising a single BM Unit as described in Section K4.1.3 [of the BSC].”
Station Load	The Station Load is equal to the sum of the demand of BM Units solely comprising the Station Transformers within the Power Station. For the avoidance of doubt, Station Load excludes BM Units comprising Additional Load

Station Transformer
Defined in the Grid Code "as a transformer supplying electrical power to the auxiliaries of a power station which is not directly connected to the generating unit terminals."

Supplier
A holder of an electricity supply licence

Supplier Half Hourly Demand
Means BM Unit Metered Volumes (QM_{ij}) expressed as a positive number (i.e. ?QM_{ij}) of the Trading Unit during the three Settlement Periods of the Triad due to half-hourly metered imports

Supplier Non Half-Hourly Demand
Means BM Unit Metered Volumes (QM_{ij}) expressed as a positive number (i.e. ?QM_{ij}) of the Trading Unit over the charging year between Settlement Periods 33 to 38 due to Non-half-hourly metered imports

Supplier Volume Allocation
Defined in the BSC as:

"the determination of quantities of Active Energy to be taken into account for the purposes of Settlement in respect of Supplier BM Units"

Total System
Has the meaning given to that expression in the Transmission Licence i.e. "…the transmission and distribution systems of all authorised electricity operators which are located in England and/or Wales"

Trading Party
As defined in the BSC

Trading Unit
Defined in the BSC as:

"a BM Unit or a combination of BM Units established in accordance with and satisfying the requirements of Section K4 [of the BSC]"

Transmission Entry Capacity (TEC)
As defined in the Connection and Use of System Code

Transmission Licence
The licence granted to National Grid Company plc under Section 6(1)(b) of the Act

Transmission Network Use of System Demand Reconciliation Charges
Has the meaning given in the Connection and Use of System Code

Transmission Owner Activity
The function of National Grid's Transmission Business covered under the Transmission Owner Activity Price Control

Transmission system
The system which consists (wholly or mainly) of high voltage lines and electrical plant owned or operated by National Grid and used for the transmission of electricity from one generating station to a substation or to another generating station or between substations or to any Interconnector

Transmission voltage
Voltages above 132kV - usually 275kV and 400kV

Triad
Is used as a short hand way to describe the three settlement periods of highest transmission system demand, 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 to February inclusive

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Revision 1	Implementation of modification UoSCM-M-12: Proposed change to the TNUoS Demand Monthly Charges Rules	pp. 21-22, 26, 46-49
Revision 2	Amendment to Application Fee rules following implementation of UoSCM-M-13: Introducing a new charge for Short Term Transmission Access	pp. 27, 82
Revision 3	New STTEC charge following implementation of UoSCM-M-13: Introducing a new charge for Short Term Transmission Access	pp. 3-4, 18-19, 25-27, 47, 84