# MODELLING REQUIREMENTS SPECIFICATION for Modification Proposal P198

# 'Introduction of a Zonal Transmission Losses Scheme'

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**Proposed Modification P198** seeks to allocate the costs of variable transmission losses to BSC Parties on a 'zonal' basis, according to the extent to which each Party gives rise to them.

## BACKGROUND AND PURPOSE OF DOCUMENT

The BSC Panel considered P198 at its meeting on 12 January 2006 and submitted the proposal to a 4-month Assessment Procedure to be conducted by the P198 Modification Group ('the Group'). The Group agreed that modelling of the likely impact on allocation of Transmission Losses under P198 should be performed to support its development and assessment of P198. This document is a requirement specification for the load flow modelling service necessary to support the P198 Assessment Procedure.

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# 1 BACKGROUND

### 1.1.1 Types of Transmission Losses

The total metered energy which can be drawn from the Transmission System to meet demand will always be less than that delivered onto the Transmission System by generation, since some energy is used up in the process of transporting electricity. This 'lost' energy is commonly referred to as 'transmission losses'. Transmission losses can be considered to comprise two main elements: 'fixed' losses and 'variable' losses.

**Fixed losses** are those which do not vary significantly with the power flow. In transformers, the losses arise from magnetising the iron core. In overhead lines, they include losses dependent on the voltage levels, length of line and climatic conditions.

**Variable losses** arise through the heat caused by current flowing through the transformers and lines. Variable losses increase with the current (and associated power flow) and the length of line in which it flows.

References to 'fixed' and 'variable' losses throughout this document have the meaning given above, whilst the term **'total' transmission losses** is used to represent the sum of fixed and variable losses (i.e. the total energy lost from the Transmission System at any given point in time, calculated as the difference between total generation and demand).

## 1.2 Existing Allocation Mechanism for Transmission Losses

The rules and calculations for allocating transmission losses to Parties are set out in Section T2 of the Balancing and Settlement Code ('the Code'). These involve the adjustment of Metered Volumes in Settlement to take account of losses (i.e. the adjustment ensures that total generation and total demand match in any given Settlement Period). Each Party's share of transmission losses is therefore taken account of as part of its Trading Charges.

Under the existing Code provisions, both fixed and variable transmission losses in each Settlement Period are allocated to Parties on a 'uniform' basis in proportion to each Party's metered energy. The current allocation of transmission losses therefore does not take account of the extent to which individual Parties give rise to losses. Although a parameter for a non-uniform, 'differential' allocation of some or all transmission losses is included in the Code, this is currently set to zero so has no practical effect. In the Section T calculation, this parameter is represented by the **Transmission Loss Factor** (TLF=0). This value can only be amended through a modification to the Code.

The formula below represents a simplified version of the Section T calculation for each BM Unit's share of total transmission losses in any given Settlement Period:

$$TLM=1+TLF+TLMO$$

A **Transmission Loss Multiplier** (TLM) is generated for each individual BM Unit, and represents a factor used to scale the BM Unit's Metered Volumes in Settlement. The purpose of the **Transmission Losses Adjustment** (TLMO) is to allocate the proportion of transmission losses which has not already been allocated through the TLF. Metered Volumes for BM Units in 'delivering' (production) Trading Units are scaled down (multiplied by $1+TLF+TLMO^{+}$), whilst Metered Volumes for BM Units in 'offtaking' (consumption) Trading Units are scaled up (multiplied by $1+TLF+TLMO^{-}$).

The value of $TLMO^{+/-}$ is produced by a separate calculation in Section T. This includes the application of an '$\alpha$ factor' of 0.45, which adjusts the total transmission losses for the Settlement Period such that 45% of losses are allocated across all delivering Trading Units whilst 55% are allocated across all offtaking Trading Units.[1]

The formulae below represent simplified versions of the $TLMO^{+}$ and $TLMO^{-}$ calculations:

> *$TLMO^{+}$ = (0.45*(generators' share of total transmission losses in Settlement Period) – generators' share of transmission losses already allocated through TLF in Settlement Period) / total volume of generation in Settlement Period*
>
> *$TLMO^{-}$ = (0.55*(Suppliers' share of total transmission losses in Settlement Period) – Suppliers' share of transmission losses already allocated through TLF in Settlement Period) / total volume of demand in Settlement Period*

The values of $TLMO^{+}$ and $TLMO^{-}$ are therefore identical for each BM Unit to which they apply.

Since under the existing Code baseline the value of TLF is set to zero, the TLMO is currently the only determining factor in the calculation of each BM Unit's TLM. Two uniform TLM values are therefore currently applied: one to all BM Units in delivering Trading Units, and one to all BM Units in offtaking Trading Units. Each Party's overall allocation of transmission losses is dependent on the Metered Volumes of the BM Units to which this TLM is applied.

## 1.3 Modification Proposal P198

P198 was raised on 16 December 2005 by RWE Npower ('the Proposer').[2] The Proposer argues that the existing locational split between northern generation and southern demand is not economic, efficient or good for the environment, since it results in the transportation of electricity over large distances – increasing the amount of energy lost through variable (heating) losses, and thereby the amount of carbon emissions. The Proposer argues that the Code's current uniform allocation of variable losses does not provide the appropriate economic signals to site new generation closer to existing demand (and vice versa), since it fails to target the costs of such losses on those Parties who give rise to them (i.e. those Parties who cause electricity to be transported the furthest distance). The Proposer considers that this results in a cross-subsidy, whereby southern generators and northern consumers have to pay part of the costs of transmitting electricity to the south.

P198 seeks to allocate the costs of variable losses to Parties on a 'zonal' basis, according to the extent to which each Party gives rise to them. In the short-term, the Proposer believes that this would remove existing cross-subsidies and lead to more efficient despatch (i.e. more efficient use of existing generation closer to demand). In the longer-term, the Proposer believes that cost-reflective zonal charging would encourage more efficient siting of new plant and load in areas where generation or demand is respectively limited – ultimately reducing the distance travelled by electricity, and thereby the overall amount of losses and carbon emissions.

The solution proposed by P198 is based closely on Proposed Modification P82, and involves the following methodology for calculating non-zero TLFs:

- An electrical model of the Transmission System (a '**Load Flow Model**') would be developed, containing 'nodes' to represent points where energy flows on or off the system. Each node would be allocated to a specific zone on the network. These **TLF zones** would be set by the Panel, based on the geographical areas covered by existing GSP Groups.

[1] In practice, this is designed to be equivalent to a 50:50 allocation, since metering for generation connections is on the high voltage side of the supergrid transformer, whereas that for demand is on the low voltage side. The 45:55 allocation of transmission losses therefore includes supergrid transformer losses for demand connections but excludes them for generation.
[2] A copy of the Modification Proposal can be found in Annex 1.

- Prior to the start of each BSC Year (1 April – 31 March), the Load Flow Model would be run by a TLF agent/service provider to calculate how a variation in generation or demand at each individual node would affect the total transmission losses from the Transmission System. This 'marginal' methodology would be applied using Metered Volumes and network data for sample Settlement Periods from a preceding 'reference' year. The output of the Load Flow Model would be a TLF value for each node in each of the sample Settlement Periods. Positive TLF values would be produced for nodes where an increase in generation (or reduction in demand) had the effect of decreasing total transmission losses. Negative TLF values would be produced for nodes where an increase in generation (or reduction in demand) had the effect of increasing total losses.
- These raw **nodal TLFs** would be averaged across all the nodes in each TLF zone by 'volume-weighted' averaging, to give a **zonal TLF** for each sample Settlement Period. These would then be converted to **annual zonal TLFs** by 'time-weighted' averaging.
- The annual zonal TLFs would be adjusted through a 'scaled marginal' methodology, using an appropriate scaling factor such that they represented only the variable element of transmission losses. These **adjusted annual zonal TLFs** would be endorsed by the Panel before being used in the TLM cost-recovery calculation for the applicable BSC Year. A positive TLF value would increase the value of TLM used to scale a BM Unit's Metered Volumes (a benefit to generators and disadvantage to Suppliers), whilst a negative TLF value would decrease the value of TLM (a benefit to Suppliers and disadvantage to generators).
- The remaining 'fixed' element of transmission losses would continue to be recovered under the Code's existing uniform calculation of $TLMO^{+/-}$. The existing overall 45% production / 55% consumption allocation of total transmission losses would also be retained within the TLMO calculation.

## 2 PROCESS

The Panel, the body that oversees the management, development and implementation of the BSC, has submitted P198 to the 'Assessment Procedure'. The purpose of this procedure is the evaluation of the proposal.

The Panel has charged the P198 Modification Group (the 'Group') with undertaking the Assessment Procedure. This involves appraising and developing the proposals in consultation with the industry and other interested stakeholders, and, finally, making recommendations to the Panel to reject or approve the proposal.

To support assessment of P198, ELEXON, on behalf of the Group is seeking to procure a modelling service to consider, amongst other things, the magnitude and variability of TLFs under the proposed scheme. The modelling objectives, input data requirements, the anticipated modelling process and the outputs required from this exercise are set out in sections 3, 4 5 and 6 of this document. Actual metered data, and network configuration information will be provided to enable the modeller to run various modelling scenarios and estimate various sensitivities.

The work will require grouping and post-processing of data from the system load flow model in a form specified by the Group. For example, information to enable geographical zones to be mapped to nodes will be provided for this purpose. The post processing of data will also require the processing and presentation of data in terms of TLFs.

This document specifies the requirements for the load flow modelling service necessary to support the P198 Assessment Procedure. The following sections set out the objectives of the modelling, the input data that will be provided by ELEXON, modelling process to be followed and output required from the Service Provider.

# 3 MODELLING OBJECTIVES

## 3.1 Overall Objectives

This section sets out the high-level objectives of the modelling service required. A set of detailed tasks are contained in Annex 3. These objectives will need to be applied to a range of generation and demand scenarios that will replicate typical conditions of the transmission system during different seasons, days and Settlement Periods. The inputs, processing and outputs that are required to facilitate achievement of these objectives are described in sections 4, 5 and 6, respectively.

## 3.2 Objective A - Calculation of TLFs

The Service Provider will generate TLFs; factors representing the change in transmission losses arising from marginal changes in demand or generation at nodes on the transmission network. TLFs will need to be generated under a range of specified scenarios.

Using the TLFs calculated by the Service Provider, TLMs will be calculated by ELEXON.

## 3.3 Objective B – Estimation of Predictability & Stability of TLFs

The Service Provider will establish the sensitivity of TLFs to changes in demand and generation by both time and location. In addition, the variability of TLFs will need to be estimated for several time frames. The changes to be modelled will be specified under the scenarios made available to the Service Provider.

## 3.4 Objective C - Credible & Accurate Model

To ensure that the TLFs generated by the model are as accurate as possible, the model should accurately represent the physical characteristics of the GB transmission network. In addition, the input data should reflect the conditions prevailing on that network at the time in question.

To ensure that the TLFs generated are credible, all assumptions used in the modelling should be credible, accurate and clearly described.

## 3.5 Objective D – Transparent Model

To ensure maximum transparency of the modelling undertaken, the operation of the model and all input data must be objectively derived from public sources (or provided by ELEXON) and all assumptions must be clearly stated. Output data should be in a readily usable format. Finally, the model should be flexible and capable of quick turn around.

# 4 INPUT DATA

## 4.1 Model Data Handling Capabilities

The model operated by the Service Provider must possess the capability to model a set of specified scenarios, detailed below, using input data provided by ELEXON.

The Service Provider will offer a model that captures 'Delivery' (i.e. injections onto the network) and 'Off-take' (i.e. withdrawals from the network) for a large number of 'nodes' (i.e. points on the network) and Settlement Periods, scattered throughout a year. For guidance, ELEXON expects the model to contain at least 100 nodes and to be capable of estimating TLFs for at least 600 representative Settlement Periods over a year.

## 4.2 Input Data Provided

ELEXON will provide the following input data, for the period 1 April 2005 to 31 January 2006:

- **Generation and Demand Metered Volumes expressed in MWh for each Settlement Period under consideration (for Grid Supply Points (GSPs), directly connected BM Units and Interconnectors)**
- **Mapping information relating BM Units, GSPs and Interconnectors to Nodes on the transmission network**
- **Mapping information relating Nodes to Zones**
- **Network Configuration Data (in PSSE format) for the following interpretation of the GB transmission network:**

  (a) 'Intact Network': the complete transmission network, assuming no circuits de-energised or disconnected (i.e. all lines in operation); and

  (b) 'Indicative Network': an approximation of the transmission network in existence at a specific point in time (i.e. Settlement Period specific). Such an approximation will be based on subtraction of known outages at that time from the intact network.

The Service Provider should note that, due to the combination of actual metered data with various approximations of the network at the corresponding times, manipulation of the data sets will be required. The scaling of demand to match generation and losses on the system, given a particular network configuration, will be necessary.

In addition, it should also be noted that the data to be supplied to the Service Provider is sufficient to run a DC load flow model. The scope of the analysis to be performed does not require the operation of an AC load flow model.

## 4.3 Input Data Sets

ELEXON will provide the following data sets, combining various sets of Metered Volumes and network configurations, to the Service Provider:

### 4.3.1 Data Set 1

The following data will be provided for the 600 'base-case' Settlement Periods to support Task 1:

- HH Metered Volumes for each directly connected BM Unit, Grid Supply Point and Interconnector
- Network ('intact' i.e. one Network for all Settlement Periods considered)

- Weighting factor for each Settlement Period (for purpose of determining annual average values)

### 4.3.2 Data Set 2

In order to consider the variability of TLFs with time under Task 2, the following data will be provided:

- Specified groupings of Settlement Periods and weightings to derive Seasonal (4), Monthly (10) and Daily Average TLFs (16)

### 4.3.3 Data Set 3

No additional input data will be required for Task 3.

### 4.3.4 Data Set 4

No additional input data will be required for Task 4.

### 4.3.5 Data Set 5

To support consideration of the sensitivity to the use of an Intact Network the following data will be provided:

- 4 Indicative Networks (Summer, Autumn, Winter, Spring)
- Details of the range of Settlement Periods to which each Indicative Network is relevant

### 4.3.6 Data Set 6

To support consideration of the impact of constraints on TLFs under P198, the following data will be provided:

- 1 Indicative Network (indicating a typical constrained network)
- HH Metered Volumes for each directly connected BM Unit, Grid Supply Point and Interconnector for a constrained Settlement Period

### 4.3.7 Data Set 7

To support consideration of sensitivity to Interconnector flows the following data will be provided:

- HH Metered Volumes for similar Settlement Periods where:
    - Both French and Moyle Interconnectors importing
    - French Interconnector importing and Moyle Interconnector exporting
    - French Interconnector exporting and Moyle Interconnector importing
    - Both French and Moyle Interconnectors exporting

### 4.3.8 Data Set 8

To assess the sensitivity of TLFs to the re-location of generation and demand, the following data will be provided:

- Data Set 1 (described above) with a generator removed from the North and replaced by an identical generator in the South (i.e. remove 500MW from a specified node in the North and add to a specified node in the South)

- Data Set 1 (described above) with a generator removed from the North and replaced by an identical generator in the South (i.e. remove 1000MW from a specified node in the North and add to a specified node in the South)
- Data Set 1 (described above) with a generator removed from the North and replaced by an identical generator in the South (i.e. remove 1500MW from a specified node in the North and add to a specified node in the South)
- Data Set 1 (described above) with a generator removed from the North and replaced by an identical generator in the South (i.e. remove 2000MW from a specified node in the North and add to a specified node in the South)

#### 4.3.9 Data Set 9

No additional input data will be required for Task 9 (Data Set 8 will be utilised).

#### 4.3.10 Data Sets 10

To simulate breakdown/closure of plant the following data will be provided:

- Data for the Winter peak Settlement Period from Data Set 1 (described above) with a generator removed from the North (i.e. 1,500MW removed from a specified node and the shortfall in generation smeared uniformly across all other generators).
- Data for the Winter peak Settlement Period from Data Set 1 (described above) with a generator removed from the South (i.e. 1,500MW removed from a specified node and the shortfall in generation smeared uniformly across all other generators).
- Data for the Summer peak Settlement Period from Data Set 1 (described above) with a generator removed from the North (i.e. 1,500MW removed from a specified node and the shortfall in generation smeared uniformly across all other generators).
- Data for the Summer peak Settlement Period from Data Set 1 (described above) with a generator removed from the South (i.e. 1,500MW removed from a specified node and the shortfall in generation smeared uniformly across all other generators).
- Data for the Autumn peak Settlement Period from Data Set 1 (described above)with a generator removed from the North (i.e. 1,500MW removed from a specified node and the shortfall in generation smeared uniformly across all other generators). Elexon will indicate which plants will be affected.
- Data for the Autumn peak Settlement Period from Data Set 1 (described above) with a generator removed from the South (i.e. 1,500MW removed from a specified node and the shortfall in generation smeared uniformly across all other generators).
- Data for the Spring peak Settlement Period from Data Set 1 (described above)with a generator removed from the North (i.e. 1,500MW removed from a specified node and the shortfall in generation smeared uniformly across all other generators).
- Data for the Spring peak Settlement Period from Data Set 1 (described above) with a generator removed from the South (i.e. 1,500MW removed from a specified node and the shortfall in generation smeared uniformly across all other generators).

#### 4.3.11 Data Set 11

For the baseline Settlement Periods from Task 1 (i.e. 600 Settlement Periods); a number of scenarios will be considered whereby intermittent generation is introduced at various locations on the Transmission System.

The impact on TLFs will then be considered. Alternative Scenarios will be generated by ELEXON based on the following approach:

1- An existing intermittent source of generation will be identified;

2- Using Metered Data, a representative output pattern for an intermittent generator across the 600 sample Settlement Periods will be established;

3- This output pattern across the sample Settlement Periods will then be applied to a fabricated plant of capacity equivalent to that of an intermittent source of generation likely to be introduced in the future (e.g. to 1GW capacity unit); and

4- This intermittent source of generation will be introduced into various locations in the country and the impact on Annual Average Zonal TLFs considered

To assess the sensitivity to increased intermittent generation, the following data will be provided:

- Data Set 1 (described above) with metered volumes adjusted to introduce the output of 1GW of intermittent generation to a node in Cornwall
- Data Set 1 (described above) with metered volumes adjusted to introduce the output of 1GW of intermittent generation to a node in the Scottish Boarders
- Data Set 1 (described above) with metered volumes adjusted to introduce the output of 1GW of intermittent generation to a node in the Scottish Highlands
- Data Set 1 (described above) with metered volumes adjusted to introduce the output of 1GW of intermittent generation to a node in Wales
- Data Set 1 (described above) with metered volumes adjusted to introduce the output of 1GW of intermittent generation to a node in Humberside
- Data Set 1 (described above) with metered volumes adjusted to introduce the output of 1GW of intermittent generation to a node at Grain
- Data Set 1 (described above) with metered volumes adjusted to introduce the output of 1GW of intermittent generation to a node in at Hersham

#### 4.3.12 Data Set 12

To support consideration of the impact of excluding 132KV circuits from the definition of Transmission System, Data Set 1 will be utilised and losses over 132KV circuits ignored for the purpose of calculating Zonal TLFS.  No further data will be provided for this task.

## 4.4 Service Provider Data Requirements

The Service Provider should set out what additional data will be required to provide the modelling service specified in this document and calculate the resulting TLFs using the rules set out in P198. The Service Provider should also specify the proposed source of any data to be used that ELEXON cannot provide, including any assumptions.

# 5 MODELLING PROCESS

As indicated in previous sections of this document, a model is required for calculating marginal loss factors for the GB Transmission System. The precise methodology to be used for calculating these loss factors is not specified and the Service Provider is invited to propose an approach. However, the subsections below outline the high-level requirements of the two key stages in the process - power flow modelling and data analysis/presentation.

## 5.1 Power Flow Modelling

The first stage in the modelling process requires the calculation of TLFs at each node on the system. When proposing and justifying an approach to the calculation of nodal TLFs, the following items must be considered.

### 5.1.1 Load Flow Model

All modelling should be performed using a DC Load Flow model. It should be noted that although accuracy is important, a transparent model is also required. It is important that the judgements or assumptions on input data made by the modeller are kept to a minimum. Where these judgements are required, the sensitivity of results to the assumptions should be indicated.

### 5.1.2 Methodology for Calculating Nodal TLFs

There are a number of methods of calculating TLFs at an individual node, the Service Provider should specify in detail the approach they recommend.

### 5.1.3 Developing Alternative Scenarios

The majority of the modelling required from the Service Provider requires the use of actual historic data. However, there is a requirement to examine the sensitivity of TLFs to possible changes in the future, for example, withdrawal of plant, new build or reversal of the Interconnector. This analysis will require the development of new scenarios based on historic cases. The Service Provider should indicate whether they have the capability to aid in the development of these scenarios or will require the Group to provide the necessary data.

## 5.2 Data Analysis/Presentation

The second stage in the modelling process requires the manipulation of marginal nodal TLFs to create the actual data required. The manipulations required are set out below.

### 5.2.1 Grouping Nodes into Zones

The modelling process requires grouping individual nodes into zones to calculate Zonal TLFs. Mapping information, relating nodes to zones, will be provided by ELEXON. A demand weighted TLF for each zone is required.

### 5.2.2 Scaling Zonal TLFs

The proposal for introducing zonal losses requires the use of scaled zonal TLFs. The model should be capable of applying a specified scaling factor to the fully marginal zonal TLFs. Hence, for example, if the scaling factor was 0.5, a TLF of –5% should be scaled to give a TLF of –2.5%.

#### 5.2.3 Creating Average TLFs

The proposal for introducing zonal losses requires the calculation of an annual TLF by time-weighted averaging of a number of historic scenarios. The model should be capable of producing these time-weighted average TLFs for each zone. The weighting of each scenario will be provided as an input. The model should be capable of producing TLFs for a range of periods based on time weighted averaging of specified scenarios (for example seasonal TLFs).

#### 5.2.4 Calculation of TLMs

Once the zonal TLFs have been calculated they will be converted into TLMs. However, this processing will be performed by ELEXON.

#### 5.2.5 Data Processing and Presentation

It is recognised that this modelling exercise will produce large amounts of data. It is therefore important that the data presentation is considered carefully. The Service Provider will be required to perform statistical analysis and present results in a manner that supports easy consideration of the results. The Service Provider will attend meetings of the Group to discuss the modelling approach and present results. A written report detailing the modelling performed and highlighting the conclusions which can be drawn from the results will be required.

# 6 OUTPUTS REQUIRED

The Service Provider will generate the outputs specified under each objective subsection below. The outputs from the modelling process shall be presented in a standard format. The outputs shall comprise

- Data in raw format in a standard electronic format (e.g. as CSV files);
- Summary tables where appropriate in a standard format to aid comparison between outputs and scenarios;
- Graphical representations of data; and
- A formal report outlining the modelling approach and results.

The model shall produce outputs based on the approach for calculating losses identified under Proposed Modification P198 (scaled marginal losses).

## 6.1 Proposed Modification P198

### 6.1.1 Output 1: Baseline TLFs

The Service Provider will generate TLFs for Data Set 1 outlined in Section 4.3.1 of this document. The data shall be presented in the following formats:

TLFs by Settlement Period for:

- individual nodes
- for nodes grouped by Zones

Heating losses in each line by Settlement Period

NB: Data provided at a Settlement Period level will be provided for a sample of 16 Settlement Periods selected by ELEXON (i.e. for defined subset of the 600 baseline periods).

Annual Average TLFs for:

- individual nodes
- nodes grouped into Zones

### 6.1.2 Output 2: Variability of TLFs

The Service Provider will generate:

- Seasonally Average Zonal TLFs, for 4 seasons;
- Monthly Average Zonal TLFs, for 10 months; and
- Daily Average Zonal TLFs, for 16 sample Settlement Periods.

Analysis considering the extent to which TLFs based on Seasonal, Monthly or Daily average TLFs vary from the Annual Average values proposed by P198.

### 6.1.3 Output 3: Compare Annual Average Nodal TLFs to Annual Average Zonal TLFs

Using the data generated under Task 1, a comparison should be made of the:

- Annual Average Nodal TLFs with Annual Average Zonal TLFs for Demand and Generation

This output should consider the extent to which any nodes are particularly advantaged or disadvantaged by the proposed zones.

### 6.1.4 Output 4: Establish the degree to which a scaling factor of 0.5 recovers heating losses

Using the data generated under Task 1, give consideration to different fixed values of the scaling factor and compare:

- Heating losses calculated by the model; and
- Total heating losses calculated from the Annual Average Zonal TLFs (i.e. the heating losses allocated in Settlement) for different values of the scaling factor.

Provide an analysis of whether a scaling factor of 0.5 over or under recovers heating losses. Provide a recommendation on an appropriate value should a fixed scaling factor be utilised. Provide a view on whether the scaling factor should be fixed or variable.

### 6.1.5 Output 5: Consider the Impact of utilising an Intact Network

Input data from Task 1 will be utilised; however, rather than using a single intact Network, seasonal indicative Networks will be utilised as follows:

- Spring Network
- Summer Network
- Autumn Network
- Winter Network

Utilising this data, Annual Average TLFs will be calculated for each Zone and compared to the baseline values from Task 1.

Provide analysis of the extent to which the use of Indicative Network data affects the calculation of Annual Average TLFs as compared to the use of an Intact Network.

### 6.1.6 Output 6: Sensitivity of TLFs to constraints

Using the data provided to represent a constrained Settlement Period, the Service Provider will generate:

TLFs by Settlement Period for:

- individual nodes
- for nodes grouped by Zone - both demand and generation

A comparison to the results obtained for a similar Settlement Period under Task 1 will be performed to consider the extent to which constraints affect TLFs.

### 6.1.7 Output 7: Examine Sensitivity to Flows on French and Moyle Interconnectors

Analysis is required of the impact of flows on the French and Moyle Interconnectors. The following should be calculated for Data Set 7.

- Average Zonal TLFs calculated for demand and generation in each of the 4 Settlement Periods for which Interconnector flows are being considered.

A comparison should be made between values for different Interconnector conditions to illustrate the extent to which TLFs are sensitive to Interconnector flows. Any significant differences should be highlighted and any reasons should be identified.

#### 6.1.8 Output 8: Sensitivity to Participants Responding to Signals

Analysis is required of the impact of participants responding to signals. For each scenario, Annual Average Zonal TLFs should be calculated. These should be compared to the corresponding TLFs obtained under Task 1. Any significant differences should be highlighted and any reasons should be identified.

#### 6.1.9 Output 9: Investigate the extent of demand or generation relocation produces a reduction in overall heating losses

Analysis is required of the impact on losses of participants responding to signals. For each scenario, an indication on the overall impact on total system losses should be provided.

#### 6.1.10 Output 10: Sensitivity to Breakdown/Withdrawal of Plant

Analysis is required of the impact of plant breakdown and withdrawals. For each scenario, Settlement Period Zonal Average TLFs should be calculated for data set 9. These should be compared to the corresponding TLFs obtained under Task 1. Any significant differences should be highlighted and any reasons should be identified.

#### 6.1.11 Output 11: Sensitivity to an Increase in Intermittent Generation

Analysis is required of the impact of a significant increase in intermittent generation on the system. For each scenario, Annual Average Zonal TLFs should be calculated. These should be compared to the corresponding TLFs obtained under Task 1. Any significant differences should be highlighted and any reasons should be identified.

#### 6.1.12 Output 12: Separate consideration of 132 KV

Having excluding 132KV circuits from the calculation of TLFs, revised Annual Average Zonal TLFs should be provided. These should be compared to the corresponding TLFs obtained under Task 1. Any significant differences should be highlighted and any reasons should be identified.

### 6.2 Documentation

In order that any assumptions, limitations, issues and risks associated with the use of the model and its output can be assessed, appropriate documentation should be provided.

## 7 TERMS USED IN THIS DOCUMENT

Other acronyms and defined terms take the meanings defined in Section X of the Code.

| Acronym/Term | Definition |
|---|---|
| Balancing Mechanism Unit (BM Unit) | BM Units are an accounting unit for energy flows in the Settlement process. A BM Unit is the smallest possible aggregation of plant and/or apparatus used for the determination of imports from and exports onto the system. Examples of BM Units include generating units, directly connected demand sites and demand (both half-hourly and non half-hourly) located within a GSP Group, supplied by a single supplier. |
| Trading Unit | A Trading Unit is a group of Balancing Mechanism Units (BM Units) that are close to each other on the transmission system. Because of this proximity, they are afforded "net" treatment, meaning that the overall commercial effect is the same as if |

| | |
|---|---|
| | demand occurring within the group were satisfied directly by generation within the group (or vice versa), with only the net of the two being traded over the system. |
| Transmission Loss Factor (TLF) | Transmission Loss Factors are factors allocated to BM Units in the Settlement process to reflect the transmission losses incurred by the activities of the BM Unit in question. (NB: The role of TLFs in the allocation of losses for the purpose of Settlement is detailed in Section T2 of the Balancing and Settlement Code, which is reproduced in Annex 6 of this document.) |
| Transmission Loss Adjustment (TLMO⁺ & TLMO⁻) | Transmission Loss Adjustments are factors used in the Settlement Process to ensure that each side of the market picks up the correct volume. (NB: The derivation of TLMOs is detailed in Section T2 of the Balancing and Settlement Code, which is reproduced in Annex 6 of this document.) |
| Transmission Loss Multiplier (TLM) | Transmission Loss Multipliers are multipliers, applied to BM Unit metered volumes, to modify energy flows to take into account transmission losses. (NB: The derivation of TLMs is detailed in Section T2 of the Balancing and Settlement Code, which is reproduced in Annex 6 of this document.) |
| Node | A points where energy flows on or off the Transmission System |
| Zone | A geographic area over which Nodal TLF values would be averaged. |

# 8 DOCUMENT CONTROL

## 8.1 Authorities

| Version | Date | Author | Reviewer | Reason for Review |
|---|---|---|---|---|
| 0.1 | 23/01/06 | Tom Bowcutt | John Lucas, Sarah Jones, Kathryn Coffin, Martin Thompson | For Technical Review |
| 0.2 | 24/01/06 | ELEXON Change Delivery | P198 Modification Group | For Modification Group review |
| 1.0 | 31/01/06 | ELEXON Change Delivery | Service Provider | For Use |

## 8.2 References

P198 documentation is available on the ELEXON website:

http://www.elexon.co.uk/changeimplementation/ModificationProcess/modificationdocumentation/modProposalView.aspx?propID=216

## 8.3 Intellectual Property Rights, Copyright and Disclaimer

## ANNEX 1 – MODIFICATION PROPOSAL P198

| **Modification Proposal – BSCP40/06** | **MP No: 198** *(mandatory by BSCCo)* |
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**Title of Modification Proposal** *(mandatory by originator)***:**

Introduction of a Zonal Transmission Losses scheme

**Submission Date** *(mandatory by originator)***:** 16th December 2005

**Description of Proposed Modification** *(mandatory by originator)*

It is proposed that a zonal transmission losses scheme is introduced to the GB BSC. This scheme would be based on the principles established under modification P82. A single Transmission Loss Factor (TLF) (the "applicable TLF") would be derived *ex ante* for application to generation and demand BMUs within a zone (the "applicable zone") for a relevant period (the "applicable period"). The proposed scheme would retain the current process for allocating transmission losses to generation and demand (45% of transmission losses to production accounts and 55% to consumption accounts).

Nodal marginal TLFs would be derived for each BMU from a representative collection of historic power system conditions using an intact network simulation (the "load flow model") during a previous period that provided a representation of the applicable period (the "reference year"). The transmission company would provide appropriate data for the network simulation. BSCCo would provide a load flow specification for the load flow model. The calculation of the annual TLFs would be under the governance of the BSC. A TLF Agent or a service provider would undertake the load flow modelling. The modelling process and load flow model will be subject to independent review by the Panel and BSCCo. The BSC Panel would endorse the TLFs prior to their application.

The applicable period for the zonal marginal TLFs under this proposal would be the BSC year (from April to March). Zonal marginal TLFs would be derived from nodal figures by volume-weighted averaging and time-weighted averaging for applicable zones. The applicable zones would be the geographical area in which a GSP Group lies, determined by the Panel (applying such criteria as it shall decide in its discretion). The zonal TLFs would be adjusted by an appropriate scaling factor (the "applicable scaling factor", which was set at 0.5 under P82). The value of this scaling factor would be fixed under the governance of the BSC at a level that, to a first approximation, (a) allocated the heating element of the transmission system losses on an average basis, with little under or over recovery (heating variable losses), and (b) resulted in other transmission losses being allocated on a uniform basis (fixed losses) through the parameters TLM0. Any inaccuracy in (a) would be compensated for in (b). Separate Zonal TLFs will be calculated for both generation and demand.

The zonal TLFs would be published on the Elexon website at least one month prior to the applicable period. BSCCo will map BMUs to the applicable zones. This mapping would be published at least one month prior to the application of TLFs, made available to BSC parties in electronic format and be revised from time to time. The volume of transmission losses in each Settlement Period for the applicable period would be allocated amongst individual BMUs in settlement by applying the relevant zonal TLFs, TLMO+j and TLMO-j.

In order to provide an opportunity for parties to prepare for the introduction of a zonal losses

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scheme, we propose an implementation date of April 2007. The scheme should be cost effective, not introduce unnecessary or untoward risks on parties and be simple to audit.

**Description of Issue or Defect that Modification Proposal Seeks to Address** *(mandatory by originator)*

Under the current BSC arrangements all transmission system losses are allocated to BSC parties in proportion to metered energy, whether production or consumption on a uniform allocation basis (45% to production accounts, 55% to consumption accounts). Therefore, the cost of heating (variable) transmission losses is allocated amongst BSC Parties regardless of the extent to which they give rise to them. This means that customers in the north of GB and generators in the south of England have to pay some of the costs of transmitting electricity to locations miles away from the source of generation.

The proposed scheme will enable the variable costs of transmission losses to be allocated on a cost-reflective basis and reflected on parties that cause them. The modification would remove the current cross subsidies and associated discrimination that is inherent in the uniform allocation of transmission losses.

The current allocation of transmission losses fails to provide potential connectees to the transmission system with appropriate signals regarding the implications of siting in different parts of the country. This may give rise to inefficient decisions regarding the development of new power stations or connection of new industrial loads. This results in the inefficient use of energy and unnecessary carbon emissions. A zonal transmission losses scheme would enable long-term locational signals for losses to be introduced into the GB electricity market.

It is anticipated that to the extent that the zonal charging of losses influences the use of existing generation and the location of future investment, it will reduce the total amount of electricity transmitted and therefore increase the efficient use of energy.

Earlier studies of a similar proposal have indicated that such a scheme could reduce carbon emissions in the short term by between 2000 tonnes p/a and 6000 tonnes p/a. These savings could increase to between 48,000 tonnes p/a and 127,000 tonnes p/a in the longer term.

**Impact on Code** *(optional by originator)*

**Impact on Core Industry Documents or System Operator-Transmission Owner Code** *(optional by originator)*

**Impact on BSC Systems and Other Relevant Systems and Processes Used by Parties** (*optional by originator)*

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**Impact on other Configurable Items** (*optional by originator)*

**Justification for Proposed Modification with Reference to Applicable BSC Objectives** *(mandatory by originator)*

The proposal will better facilitate BSC Objective A relating to the efficient discharge by the licensee (NGC) of the obligations imposed upon it by its licence. A zonal transmission losses scheme will remove market distortions and the discrimination that exist in the present arrangements.

The proposal will better facilitate BSC Objective B by enhancing the efficient, economic and co-ordinated operation by the licensee (NGC) of the licensees transmission system. Adoption of a zonal transmission losses scheme will remove cross subsidies which the present uniform charging for transmission losses create. A zonal transmission losses scheme will therefore enhance efficiency through more cost reflective charging which could be expected to influence both short term plant despatch and long term business decisions influencing investment in both generation and demand.

This proposal will also contribute to better achieving the BSC objective C relating to the promotion of effective competition in the generation and supply of electricity, and (so far as consistent therewith) and the promotion of such competition in the sale and purchase of electricity. In particular:

- The proposal will introduce a cost reflective allocation of transmission losses according to the degree to which BMUs in an applicable zone give rise to losses;
- The proposal removes the current cross subsidies between customers (north to south) and generators (south to north) that occur through the uniform allocation of transmission losses;
- The allocation of losses to zones will enable the costs to be reflected on generation and demand in a manner that does not unduly penalise individual BMUs;
- A scheme based on the ex ante calculation of zonal loss factors will enable users of the transmission system to estimate the impact and appropriately reflect the costs;
- A zonal scheme would provide better information to users of the transmission system regarding the implications of siting generation and new load in different parts of the country; and
- In the longer term zonal allocation of transmission losses would encourage appropriate investment in generation or new load in areas which currently have limited capacity relative either to generation or demand. This will ultimately bring down the overall costs of losses with benefits for customers and the environment.

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| **Details of Proposer:**<br><br>***Name: Terry Ballard***<br><br>***Organisation: RWE Npower***<br><br>***Telephone Number: 07989 493038***<br><br>***Email Address: terry.ballard@rwenpower.com*** | |
| **Details of Proposer's Representative:**<br><br>***Name: Bill Reed***<br><br>***Organisation: RWE Trading***<br><br>***Telephone Number: 01793 893835***<br><br>***Email address: bill.reed@rwe.com*** | |
| **Details of Representative's Alternate:**<br><br>***Name: Terry Ballard***<br><br>***Organisation: RWE Npower***<br><br>***Telephone Number: 07989 493038***<br><br>***Email Address: terry.ballard@rwenpower.com*** | |
| **Attachments: No** *(delete as appropriate) (mandatory by originator)*<br><br>**If Yes, Title and No. of Pages of Each Attachment:** | |

# ANNEX 2 – SECTION T2 OF THE BSC

The current allocation of transmission losses is detailed under section T2 of the BSC, the calculation involved are reproduced below.

## 2. ALLOCATION OF TRANSMISSION LOSSES

### 2.1 Delivering and Offtaking Trading Units

2.1.1 For the purpose of scaling for transmission losses, in respect of each Settlement Period,

(a) a Trading Unit is a "**delivering**" Trading Unit when $\Sigma_i QM_{ij} > 0$ and

(b) a Trading Unit is an "**offtaking**" Trading Unit when $\Sigma_i QM_{ij} \leq 0$

where $\Sigma_i$ represents the sum over all BM Units belonging to that Trading Unit.

### 2.2 Transmission Loss Factors

2.2.1 For the purposes of the Code, the Transmission Loss Factor for each BM Unit, and factor $\alpha$, shall be as follows:

(a) $TLF_{ij} = 0$ for all BM Units, and

(b) $\alpha = 0.45$.

### 2.3 Determination of the Transmission Loss Multipliers

2.3.1 In respect of each Settlement Period, for each BM Unit, the Transmission Loss Multiplier shall be calculated as follows:

(a) for all BM Units belonging to Trading Units which in the Settlement Period are delivering Trading Units:

$$TLM_{ij} = 1 + TLF_{ij} + TLMO^{+}_{j}$$

(b) for all BM Units belonging to Trading Units which in the Settlement Period are offtaking Trading Units:

$$TLM_{ij} = 1 + TLF_{ij} + TLMO^{-}_{j}$$

Where:

$$TLMO^{+}_{j} = -\{\alpha(\Sigma^{+}QM_{ij} + \Sigma^{-}QM_{ij}) + \Sigma^{+} (QM_{ij} * TLF_{ij})\}/ \Sigma^{+}QM_{ij} \text{ ; and}$$

$$TLMO^{-}_{j} = \{(\alpha-1)(\Sigma^{+}QM_{ij} + \Sigma^{-}QM_{ij}) - \Sigma^{-} (QM_{ij} * TLF_{ij})\}/ \Sigma^{-}QM_{ij} \text{ ; and}$$

$\Sigma^{+}$ represents the sum over all BM Units belonging to Trading Units that are delivering Trading Units in the Settlement Period;

$\Sigma^{-}$ represents the sum over all BM Units belonging to Trading Units that are offtaking Trading Units in the Settlement Period.

## ANNEX 3 – MODELLING TASKS

**Proposed Modification P198:**

| Task | Inputs | Output | Objective |
|---|---|---|---|
| **1. Establish baseline TLFs**<br>Use 600 Settlement Periods for calculating baseline TLFs | • Mapping of Nodes to Zones<br>• Mapping of directly connected BM Units, GSPs and Interconnectors to Nodes<br>• Intact Network<br>• For each Settlement Period, Half-hourly metered data for each directly connected BM Unit, GSP and Interconnector<br>• Weighting for each Settlement Period | For each Settlement Period:<br>TLFs for<br>• individual nodes<br>• each Zone<br>Heating losses in each line<br>NB: For the purpose of data provision information will only be required for 16 of the 600 Settlement Periods.<br>Annual Average Zonal TLFs | Provide a baseline against which sensitivities can be considered<br>Illustrate the likely patterns of loss allocation under P198 |
| **2. Consider temporal variability of TLFs**<br>Consider alternative averaging periods for TLFs, including:<br>• Seasonal (consider 4 seasons)<br>• Monthly (consider 10 months)<br>• Daily (consider 16 day types) | • Outputs from Task 1<br>• Specified groupings of Settlement Periods and weightings to derive Seasonal, Monthly and Daily Average TLFs | Seasonally Average Zonal TLFs<br>Monthly Average Zonal TLFs<br>Daily Average Zonal TLFs | Compare outputs to annual values for annual averaging under Task 1<br>Consider the extent to which a seasonal, monthly or daily average TLF deviates from an annual average value<br>Support consideration of potential alternatives |
| **3. Compare Annual Average Nodal TLFs to Annual Average Zonal TLFs** | Nodal and Zonal TLF results obtained under Task 1<br>Weighting for each Settlement Period (as Task 1) | Comparison of Average Annual Nodal TLFs to Average Annual Zonal TLFs | Supports consideration of whether the mapping of Nodes has a significant impact on annual TLF value |

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| **4. Establish the degree to which a scaling factor of 0.5 recovers the heating losses**<br><br>Consider different values for the Scaling Factor and identify value likely to give best recovery heating losses | Settlement Period Zonal TLF values and heating losses obtained under Task 1 | For different fixed values of the scaling factor:<br>• Actual heating losses<br>• Losses calculated from the Annual Average Zonal TLFs | Does the scaling factor systematically over or under recover the heating losses?<br><br>Provide a view on a suitable value for a fixed scaling factor<br><br>Provide a view on whether the scaling factor should be fixed or variability |
| **5. Consider impact of utilising an Intact Network**<br>Recalculate the Annual Average Zonal TLFs using the baseline Settlement Periods from Task 1 but using Indicative Network data rather than an Intact Network | • For each Settlement Period, Half-hourly metered data for each directly connected BM Unit, GSP and Interconnector (as utilised in Task 1)<br>• Indicative Networks for:<br>– Spring<br>– Summer<br>– Autumn<br>– Winter<br>• Weighting for each Settlement Period (as utilised in Task 1)<br>• Mapping of Nodes to Zones (as utilised in Task 1) | Annual Average Zonal TLFs | Consider the extent to which Annual Average TLFs calculated using Indicative Network data vary to those generated using an Intact Network<br><br>Provides information on validity of using a single intact network for calculation of TLFs |

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| **6. Examine sensitivity to constraints**<br><br>Consider a Settlement Period impacted by a constraint on the Network and compare TLFs to values for a similar unaffected period established under Task 1. | • 1 Indicative Network (Indicating a typical constrained network)<br>• HH Metered Volumes for each directly connected BM Unit, Grid Supply Point and Interconnector for a constrained Settlement Period<br>• Mapping of Nodes to Zones (as Task 1)<br>• Mapping of BM Units, GSPs and Interconnectors to Nodes (as Task 1) | For the Settlement Period considered:<br><br>TLFs calculated for<br>• individual nodes<br>• each Zone<br><br>Compare these results to those for a similar Settlement Period used in Task 1 | To support consideration of whether it is necessary to consider constraints within the network model |
| **7. Examine sensitivity to flows on French and Moyle Interconnectors**<br>Compare Zonal TLFs for Settlement Periods which are similar but have:<br>1. Both French and Moyle Interconnectors importing<br>2. French importing and Moyle exporting<br>3. French exporting and Moyle importing<br>4. Both French and Moyle Interconnectors exporting | • For each Settlement Period, HH Metered Volumes for each directly connected BM Unit, Grid Supply Point and Interconnector<br>• Intact Network (as Task 1)<br>• Mapping of Nodes to Zones (as Task 1)<br>• Mapping of directly connected BM Units, GSPs and Interconnectors to Nodes (as Task 1) | Average Zonal TLFs calculated for each of the 4 Settlement Period for which Interconnector flows are being considered. | For each Settlement Period considered compare the Settlement Period Zonal TLF values to the Annual Average Zonal TLF values calculated under task 1.<br><br>Supports consideration of the extent to which TLFs on a day are likely to vary from Annual Average TLFs due to Interconnector flows. |

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| **8. Examine sensitivity of Annual TLFs to participants responding to signals**<br><br>For each of the baseline Settlement Periods from Task 1, create a new scenario where generation is relocated in response to TLF values established under Task 1:<br>- 0MW<br>- 500MW<br>- 1GW<br>- 1.5GW<br>- 2GW<br>Adjust other plant appropriately | • HH Metered Volumes for each directly connected BM Unit, Grid Supply Point and Interconnector, for each adjusted scenario<br>• Intact Network (as utilised in Task 1)<br>• Mapping of Nodes to Zones (as Task 1)<br>• Mapping of directly connected BM Units, GSPs and Interconnectors to Nodes (as Task 1) | For each new scenario:<br><br>Average Annual Zonal TLFs | Compare Annual Average TLFs to those generated in Task 1.<br><br>Supports consideration of the impact on TLFs of participants responding to signals. |
| **9. Investigate the extent of demand or generation relocation produces a reduction in overall heating losses**<br><br>For each of the Settlement Periods utilised in Task 1 , relocate a volume of generation from north to south:<br>- 0MW<br>- 500MW<br>- 1GW<br>- 1.5GW<br>- 2GW<br>Estimate reduction in total losses on the System for each case | Settlement Period Zonal TLF values and heating losses obtained under Task 8 | For each case, an estimate of the impact on the total heating loses on the system | Support consideration of the benefits of the proposal. |

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| **10. Examine sensitivity to breakdown / withdrawal of plant**<br><br>For four of the Baseline Settlement Periods (Summer Peak, Winter Peak, Spring Peak and Autumn Peak) from Task 1, create 2 new scenarios for:<br><br>Scenario 1 – 1,500 MW plant in north absent<br><br>Scenario 2 – 1,500 MW plant in south absent<br><br>Adjust other plant appropriately | • HH Metered Volumes for each directly connected BM Unit, Grid Supply Point and Interconnector, for each adjusted scenario<br>• Mapping of Nodes to Zones (as utilised in Task 1)<br>• Intact Network (as utilised in Task 1)<br>• Mapping of directly connected BM Units, GSPs and Interconnectors to Nodes (as Task 1) | For the Settlement Period considered in each scenario:<br><br>TLFs calculated for each Zone | Compare results from these scenarios with results obtained for task 1<br><br>Does removal of plant introduce more volatility to TLFs? |

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| **11. Modelling of intermittent generation**<br><br>For the baseline Settlement Periods from Task 1 (i.e. 600 Settlement Periods); a number of scenarios will be considered whereby intermittent generation is introduced at various locations on the Transmission System. The impact on TLFs will then be considered.<br><br>Alternative Scenarios will be generated by ELEXON based on the following approach:<br><br>1- An existing intermittent source of generation will be identified<br>2- Using Metered Data, a representative output pattern for an intermittent generator will be established<br>3- This output pattern will then be applied to an intermittent source of generation likely to be introduced in the future (e.g. to 1GW capacity unit).<br>4- This intermittent source of generation will be introduced into various locations in the country and the impact on annual average TLFs considered. | • HH Metered Volumes for each directly connected BM Unit, Grid Supply Point and Interconnector, for each adjusted scenario<br>• Mapping of Nodes to Zones (as utilised in Task 1)<br>• Intact Network (as utilised in Task 1)<br>• Mapping of directly connected BM Units, GSPs and Interconnectors to Nodes (as Task 1) | For each adjusted scenario<br><br>TLFs for<br>• individual nodes<br>• each Zone | How sensitive are TLFs to variable generation? |

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| **12. Separate consideration of 132 KV**<br><br>To support consideration of the impact of excluding 132KV circuits from the definition of Transmission System Data Set 1 will be utilised and losses over 132KV circuits ignored for the purpose of calculating Zonal TLFS. As a consequence of ignoring losses over 132KV circuits, TLFS at each node will be impacted. | • Mapping of Nodes to Zones (as task 1)<br>• Mapping of directly connected BM Units, GSPs and Interconnectors to Nodes (as task 1)<br>• Intact Network (as task 1)<br>• For each Settlement Period, Half-hourly metered data for each directly connected BM Unit, GSP and Interconnector (as task 1)<br>• Weighting for each Settlement Period (as task 1)<br>• Identification of 132KV circuits | Annual Average Zonal TLFs | Consider the impact of 132KV circuits being excluded from the calculation |