Methodology Options to be considered for the Implementation of Location Signals on the Island of Ireland

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TABLE OF CONTENTS

Executive Summary

Since 2006 there has been a number of consultations and publications regarding harmonization of tariffs and transmission locational signals on the island of Ireland. So far, no acceptable all-island tariff arrangement has been agreed which delivers transmission locational signals in line with the original SEM high level design[1]. Earlier this year the Commission for Energy Regulation ("CER") and the Northern Ireland Authority for Utility Regulation ("NIAUR"), collectively known as the Regulatory Authorities (RAs) asked that EirGrid and SONI, the System Operators (SOs) in the Republic of Ireland (ROI) and Northern Ireland (NI), respectively, organise a workshop and develop a paper examining the various options that are available. The workshop took place in March and was attended by a number of industry participants and interest groups. In order to get as many responses as possible, the SOs organised a questionnaire on the subject and made a call for industry papers. In early May a paper was published which summarised the responses to the questionnaire[2]. In addition to this paper, the submissions, which were received from the electricity industry, were also posted.

Using feedback from the industry and input from the RAs, the SOs recommended a number of objectives for the methodologies under investigation. These include cost reflectivity, transparency, predictability, non-volatility, the promotion of efficient future network planning, consistency between demand and generation and short run efficiency (mainly through a losses mechanism). It is unlikely that ideal methodologies will be found which respect all objectives and therefore trade offs between options will be necessary.

In order to identify possible options which would achieve the project and design objectives, research was carried out on tariff and losses

[1] SEM proposed High level Design paper, March 2005 (AIP/SEM/06/05) and High level Design decision paper, June 2005 (AIP/SEM/42/05) available on www.allislandproject.org

[2] Workshop, Questionnaire and Industry Paper, April 2009 (SEM-09-046) available on www.allislandproject.org

methodologies used abroad. A full listing of the various arrangements reviewed is included in the Appendix.

There are a number of economic and research considerations that are pertinent for the review. The first is the requirement to send signals to users of the network regarding the costs they impose on network development. Given that users pay shallow connection costs,it may be considered appropriate that they should pay locational Use of System charges so as to contribute to the cost of deep reinforcements which their connection has caused. It is therefore important that network planning and network pricing are consistent. Network pricing generally follows two approaches: Static and Dynamic. The Static pricing model uses a constant generation and demand background and assumes that the network in question is fixed in time with the replacement cost being evaluated using an modern equivalent method. The Dynamic model, on the other hand, assumes that the network is changing over time, with the future replacement cost being of interest. These approaches are used when describing the various options outlined in the document. Section 5 also describes how pricing methodologies can allocate marginal investment cost or average investment costs. Both of these costing types can be applied to the Static and Dynamic approach. Where a locational arrangement is in place, it is unlikely that the revenue received will exactly match annual requirements. Therefore, a residual element may have to be raised using an alternative methodology. Postage stamping is often used to ensure that the required revenue is collected.

There are a number of other elements outlined in the document which highlight the challenge of identifying arrangements that comply with the SEM high level design and which are acceptable to the wider industry. These include legacy issues and a number of boundary conditions which preclude the use of certain methodologies used elsewhere.

Drawing on the experience of other countries and using the feedback from industry participants a total of six tariff options and four losses options are presented in this paper. The tariff options include two pure locational pricing models, two locational pricing models with residual elements and two models which are based around postage stamping. The losses options include loss adjustment factors, uniform losses, zonal losses and the purchase of losses. Note that in developing transmission locational signals the combined effect of both TUoS and TLAF will be considered during the next phase.

Using the objectives described in Section 3, a correlation matrix is given in Section 8 which shows how each of the Options achieves each objective. In the next phase of the project each option will undergo a process of evaluation using simulations and modelling tools. In order to choose a preferred option, the results of these simulations will be evaluated to determine the extent to which they achieve the objectives. Following the consultation on this methodology options paper, the SOs will continue to develop the preferred options, with the aim of producing a more detailed consultation paper (including indicative tariffs) focused on the preferred options. This will be followed by RA decision papers, both policy and detailed, as appropriate. After this process the project will move into the implementation phase. In all, the remaining phases of the project will take another 15-18 months with an expected completion date of Q4 2010.

1. Introduction

This document is an overview of the work that is being done by the SOs to determine if it is feasible to implement a new harmonised tariff and losses arrangement on the island of Ireland, which includes transmission locational signals in line with the original SEM High-Level Design. These signals are in the form of appropriate tariff and losses arrangements combined. The choice of design objectives reflect input that has already been received by the project team from the Regulatory Authorities and the wider industry by means of a workshop, questionnaire and submission of industry papers.

In order to design a viable methodology, the project team has carried out extensive research on international best practice in the area of tariff and losses design. This research is referenced in the main body of the document and a full listing is included in the Appendix. The aim of the research conducted is to identify whether methodologies being used abroad could be applied on the island of Ireland. In order to do this, a reference template is used to characterise each national arrangement in a consistent manner. Using this approach the research team were able to reduce the large number of methodologies studied to 6 main approaches.

The planning context (e.g. Gate3[3] and Grid 25 in Republic of Ireland) which has been developed to accommodate large amounts of wind onto the system has been taken into account as part of the review.

Full descriptions of the current methodologies being used in the Republic of Ireland and Northern Ireland are also included in the Appendix.

[3] Commission's Gate 3 Direction Paper (CER/08/260); EirGrid's Grid Development Strategy GRID25 Grid 25

The remaining sections of this document are structured as follows:

- The background and reasons for conducting this review are outlined in Section 2;
- The objectives of the project are discussed in Section 3 with a rationale for why each objective is chosen. Any such methodology shall be consistent with all network access and transmission planning arrangements;
- Section 4 sets out the process that was implemented to research best practice in relation to TUoS & losses methodologies;
- Section 5 outlines the various considerations that were taken into account while conducting research;
- Four different Losses options are described in Section 6;
- Section 7 includes a full description of six tariff options;
- The various options are analysed in Section 8 using the objectives listed in Section 3; and
- Section 9 contains a list of the next steps to be taken in the project.

2. Background

In order to deliver low long-term electricity prices to consumers of electricity, and consequently the best deal to society as a whole, the electricity industry has to ensure that, in the short-term, the system is efficiently operated and that, in the long-term, it follows the path of least cost development (efficient investment).

In the specific context of operation and expansion of the transmission network, this requires a coordinated approach to optimising generation and network operation and development, as the optimisation of the network in isolation from generation would almost certainly not meet the above objective.

One of the consequences of the introduction of competition in the power industry is the separation of generation and supply from network activities, frequently considered necessary for ensuring that open and non-discriminatory access to the energy market is developed. In this environment, pricing of use of network services (involving losses, constraints and investment) becomes the key for achieving both efficient operation and least-cost system development of the entire system. The coordination of investing in generation and networks is to be achieved through efficient network pricing mechanisms.

Clearly, if the network pricing is not efficient, this could distort competitiveness among generators of different sizes and technologies and simultaneously reduce the short term efficiency of the generation system operation and increase the cost of network investment above efficient levels.

As the issues associated with the structure of charges for connection and use of transmission systems cannot be considered in isolation, shallow connection charging policy requires an economically efficient TUoS (transmission use of system) charging methodology.

Given that the Single Electricity Market (SEM) is based on a single unconstrained marginal pricing structure, there is no locational pricing signal in the market compared to a market with, for example, location marginal pricing. During the High-Level Design stage of the SEM, it was determined that transmission locational signals in the market would be given through the treatment of losses and use of System charges. A locational losses methodology (Transmission Losses Adjustment Factors) is already running on an all-island basis.

Policies on the treatment of losses and Use of System charges have a strong link with connection policy. A policy of shallow connection charges has been adopted in the SEM therefore users connecting to the system do not have to pay for deep reinforcements which their connection has brought about the need for. A locational TUoS charging policy can be used to ensure that users contribute to the cost of deep reinforcements that they have caused. Similarly with losses, the lack of any transmission locational signal provides no incentive for generation or load to take into account the cost of losses when making decisions regarding their location.

TUoS Charging

In July 2006 and June 2007, the RAs published consultation papers on all-island generation transmission use of system ("TUoS") charging intended to apply from 1 January 2008. Corresponding decision documents were published in March 2007 and July 2007. The first of these decision documents established that, under the Single Electricity Market (the "SEM"), the locational TUoS charges paid by generators should be calculated, on an all-Island basis, using a methodology broadly based on the method presently employed by EirGrid in the Republic of Ireland. The second reported more detailed decisions concerning the application of the methodology to be used. After this time, the system operators developed indicative tariffs in accordance with the methodology. Certain aspects of the methodology, principally the costing of network elements and the assumed generation scenarios, had a more significant impact on the resulting tariffs than was first anticipated. As a result, SEM Committee deferred the application of all-island generator TUoS tariffs until 1 October 2008, pending further investigation, with the jurisdictional TUoS tariffs carried over in the meantime.

Following a subsequent consultation, 'Transmission Use of System Charging: Methodology for All-Island Generation Tariffs, June 2008', the RAs decided not to proceed with the all-island harmonisation of generator TUoS charges for the tariff year 1st October 2008 to 30th September 2009. This was as a result of the volume and nature of the concerns raised by market participants in response to this June consultation and of residual uncertainties over the impact, year-on-year tariff volatility and robustness of certain aspects of the proposed methodology.

Losses

The "SEM High-Level Design Decision Paper" in June 2005 included a decision requiring that transmission losses in the SEM be accounted for on an all-island basis, using a consistent methodology involving the application of locational Transmission Loss Adjustment Factors ("TLAFs") to the outputs of generators. Following the publication of this paper, the RAs had extensive discussions on the issue with the SOs leading to the publication in May 2006 of a consultation paper on the treatment of transmission losses. Following consideration of the comments received to the consultation paper, in August 2006 the RAs published a decision paper on the matter.

The methodology used to calculate the transmission loss adjustment factors for SEM has been developed through a number of consultation and decision documents. These papers are available on the All-island Project website.

Following a further consultation on the 2009 TLAFs in September 2008 (SEM-08-121), market participants raised a number of concerns, which included the volatility, and equitability of TLAF calculations and interaction of TLAFs with the Gate 3 process.

In response to the concerns raised by participants regarding both losses and TUoS methodologies, the RAs, in their paper of 16th January 2009 (SEM – 09-001), instructed the SOs to commence a joint review of the options and methodologies for deriving harmonised all-island transmission generator TUoS charges and TLAFs. This review facilitates the development of an enduring framework appropriate to the all-island transmission networks. The RAs outlined that the review should also include a consideration of demand TUoS charges. Before January of this year, very little work had been done to examine demand TUoS charges in the SEM. The RAs advised that the review should take into account the objectives and issues outlined by the RAs including, amongst other things, the issues of appropriate costing of the networks and the mitigation of year-on-year tariff volatility and/or unpredictability.

As part of the process, the SOs held a workshop on the 3rd of March 2009, where participants were invited to come along and meet with the RAs and SOs and express their views on TUoS and TLAF methodologies. Following the workshop, participants were requested to complete a questionnaire gathering views on a range of aspects of TUoS and TLAF methodologies. The questionnaire was used as a tool to identify opinion trends amongst organisations with regard to the transmission locational signals aspects of current and potential tariff and losses schemes. The findings from the questionnaire are being used to prioritise those characteristics and criteria, which are of utmost importance to the organisations surveyed. The results provide an important input to this Options Paper.

A number of industry papers with commentary on transmission locational signals, tariffs and losses were also received by EirGrid and SONI. The ideas in these papers in addition to the other sources of feedback have also been taken into consideration by the project team for this document.

The submissions and responses made by the industry participants reflect their experience and positions on current as well as prospective tariff and losses arrangements. While a common losses methodology (TLAF) is used in both jurisdictions, the feedback from the wider industry confirms the need to review current practices.

3. Objectives

There are a number of objectives, which have been articulated by the various stakeholders in the project (Regulatory Authorities, System Operators, Industry Participants and Industry Groups). The project team has given extensive consideration to the various objectives of each of the stakeholders. However, given the quantity and sometimes conflicting nature of these objectives, it was necessary to determine a number of primary objectives, against which the potential TUoS and losses methodologies can be assessed. The primary objectives of the TUoS and TLAF methodologies include:

1. Efficiency: To encourage efficient use of the network and efficient investment in infrastructure. This is of interest to all stakeholders as it addresses the long term sustainability of the system;
2. Transparency: The provision of information and models to ensure full transparency of all methodologies. The publication of indicative tariffs & losses for a number of years;
3. Predictability: The methodologies should enable the prediction of tariffs & losses to within a reasonable level. This predictability should be for a number of years however, it would not extend to the full investment horizon;
4. Volatility: Where possible the methodologies should avoid dramatic year on year fluctuations, so as to give contradictory signals;
5. Short term efficient dispatch (through losses methodologies): Any losses method should ensure that the dispatch is as efficient as possible. In order to achieve this objective, it will be necessary to study the effectiveness of any proposal in line with suggestions from the wider industry;
6. Cost reflectiveness: Any tariff methodology & losses methodology should be cost reflective in order to promote economic efficiency and to facilitate competition; and
7. Consistency between generation and demand methodologies: The arrangement should be consistent in their application and in how transmission locational signals are applied to generation and demand parties in a particular region.

In order to compare various options it has been decided to use an evaluation criteria to rank various options in term of how each meets the primary objectives. This can be found in section 8 of this document.

4. Research Methodology

It was decided to firstly review the current arrangements to identify opportunities for improvement. This review included the use of an online questionnaire to collate industry opinions.

The project team used international experience to help identify alternative ways of calculating tariff and losses. The purpose of conducting research on methodologies applied in other markets is to determine if a methodology applied elsewhere, or under consideration by another SO, could be applied in Ireland and Northern Ireland in order to achieve the maximum number of objectives as set out in Section 3 of this document. It was not the SOs expectation to find a perfect solution but rather to find a model structure that could be adapted in some ways to fit with the current SEM design. The SOs has examined a substantial number of pricing and losses models many of which have been outlined in the Appendix of this document. In addition, the SOs have engaged the experience of a transmission pricing and losses academic advisor to carry out a peer review of the options proposed in this paper.

A tariff template, shown in the Table 1 below, is used to characterise each arrangement so that it can be evaluated with regard to the Island of Ireland context. Table 2 shows the factors used to characterise losses methodologies as part of the research.

It is important to stress that while certain approaches may work abroad, the technical and market context of the two grids on the island of Ireland may preclude certain arrangements here. While most of the countries reviewed had transmission locational signals as part of their tariff/losses arrangements, it is acknowledged that some do not have any such signal. Finally, there were limits on the amount of information available on each model reviewed and the time available to research each model was relatively short.

Table 1: Table of Characteristics used to analyse international tariff arrangements

TUoS Tariff	
Connection Policy	This refers to the contribution payable by a user connecting to the transmission system. For example, shallow connection policy refers to the case where the user pays only for the full costs of connection and not for any deep reinforcements.
Locational (incl. load flow) Vs Postage stamp	Postage stamp allocation is a methodology whereby calculations are carried out uniformly to recover costs. No account of location or any other factor is considered. A locational methodology is one that provides appropriate entry or exit signals to a transmission system user depending on where that user is located.
Energy Vs Capacity	This outlines the proportion of the revenue which is recovered on an energy basis from users and the proportion recovered on a capacity basis.
Demand / Generation split	This identifies the proportion of TUoS costs payable by the two distinct classes of user.
Costing Approach	There are several options with regard to costing methodologies which can be characterised.
Dispatch / Scenarios (treatment of wind and interconnection)	Certain methods need transmission system scenarios to model events e.g. Load Flow based methods that need

TUoS Tariff	
	dispatch scenarios. While using such scenarios it would be necessary to make assumptions about treatment of renewables and interconnection.
Volatility Mitigation Technique	Mechanisms to reduce the year on year variation.
Network Optimisation	Certain methods may require the overall system to be more efficient while running studies e.g. remove stranded assets.
Scaling e.g. delta multiplier	It may be necessary to use a factor to relate a result for a particular customer to a base case or overall limit in order to ensure that the exact revenue requirement is recovered.
Zonal Vs Nodal	Some methodologies are based around nodes, while others are based around areas or zones.
Asset Included e.g. system support, for instance capacitor	Which assets are included in the cost calculations.
Period of interest	When will the methodology be reviewed or how often tariffs are produced using the methodology e.g. annually.
Implementation Date	This describes an estimated date when the TSOs believe the methodology could be implemented here depending on complexity etc.

Table 2: Table of Characteristics used to analyse international losses arrangements

Losses	
Location Vs Uniform	This refers to how the cost of losses is allocated to participants. Some approaches allocate losses depending on location, others have a uniform allocation.
Purchase Vs Loss Adjusted	The losses can be adjusted by loss factors which help determine the dispatch. Alternatively the losses can be purchased by the TSO.
Demand / Generation split	This identifies the proportion of the cost of losses payable by the two distinct classes of users.
Fixed / Non-fixed	Fixed losses are technical losses that are not related to load. Non-fixed (variable) losses are technical losses related to load. This indicates which type of losses the method recovers. These two types of losses can be treated differently.
Ex-ante / Ex-post	This refers to whether the losses and the cost of losses are determined ex-ante or ex-post.
Single / Multi-part	This is applicable to loss adjustment factors. Different factors can apply in different periods. Also, it refers to whether the loss factors are linearly or

Losses	
	convexly modelled.
Dispatch (treatment of wind and interconnection)	This examines how the treatment of losses affects dispatch. It also looks at how renewables and interconnection are incorporated.
Period of Application	The length of time that the loss treatment is set.
Marginal Vs Average	This refers to whether losses are calculated on a marginal or average basis.
Incumbent Vs New Entrant	This examines the treatment between different users.
Implementation Date	This describes an estimated date when the TSOs believe the methodology could be implemented.

Please note that the descriptions of other methodologies outlined in this paper represent SONI & EirGrid's understanding of the TuoS tariff and TLAF methodology based on documents made publicly available. The relevant System Operators from these countries have not been involved in any aspect of this paper and therefore have not corroborated with the description of any methodology.

In order to advance the discussion, the System Operators propose to put forward a number of options which will be analysed further in the design phase of the project. It is only in the later stages of the project that the appropriate modelling and simulations will take place. Therefore, there will be no indicative tariffs or losses available at this stage.

5. Consideration Factors

This section of the document discusses a number of factors in both jurisdictions which may impact on the chosen methodology.

5.1. Context

There are a number of boundary conditions or limiting factors, which have a significant impact on whether a particular approach would work in the Island of Ireland context including the following:

1. It is assumed that in general the Market Design Parameters will not radically change;
2. It is also assumed that the High-Level Design Paper from 2005 which references locational charges is still relevant;
3. There will be a shallow connection charging policy;
4. Any arrangement will comply with national and EU legislation;
5. The arrangements will allow for changes in revenue size;
6. It must be feasible to implement all proposals in both jurisdictions; and
7. The arrangements must be consistent with other polices and practices within the market and within both jurisdictions, (e.g. connection charging policy, firm/non-firm access arrangements, etc…)

5.2. Economic Considerations: Treatment of Losses

This section discusses the economic theory supporting the choice of options for the treatment of losses, as presented in Section 5.6 of this paper. As previously mentioned, one of the primary objectives of the treatment of losses is that the methodology should promote short-term economic efficiency in the operation of the transmission system. This short-term efficiency should lead to the situation whereby dispatch is modified to reflect the cost of losses to the system.

The modified dispatch of units should ultimately result in a reduction in fuel costs, given that in cases where two generators located on different sites can both serve a particular demand, the one situated closer to the demand, which will incur a lower volume of losses, will be the unit dispatched. When fewer losses are incurred on the system, less energy has to be produced to satisfy demand. This, in theory, should provide a signal for generation to site closer to demand and depending on whether losses are allocated to suppliers also, a signal for demand to locate closer to generation. It is possible that the allocation of losses could provide a longer-term signal for units in their choice of location.

The question arises as to how losses on the system are best reflected. Understandably, losses change depending on the operating conditions at any time on the system. There is a need to balance the stability and predictability of the losses signal with the need for the losses to be cost reflective. The SOs are also conscious that the benefits of any losses allocation mechanism should outweigh the cost of implementing and applying the mechanism. A number of alternative treatments of losses are discussed later in this document.

5.3. Economic Considerations: Treatment of TUoS

Based on the High-Level objectives for network pricing which are outlined in Section 3, this section outlines the criteria and rational for the set of options proposed further in the document.

5.3.1. Network investment drivers

Given that one of the principal objectives of network pricing is to send signals to users of the network regarding the costs they impose on network development, it is important that network planning and network pricing are consistent. This can be achieved by identifying key drivers associated with network development and corresponding investment costs. Through an efficient pricing method, users of the network need to be informed about their impact on network development costs which are the outcome of network planning exercises, hence the close link between network planning and pricing. When analyzing alternative options, consideration was given to the extent by which a particular network pricing methodology is consistent with network planning and that it captures the impact of key network planning principles on network cost (such as peak security and economic efficiency based planning).

5.3.2. Allocation of investment costs through network charges

Network pricing methodologies should follow one of two modeling approaches:

a. **Static Model**: cost of the *entire network* that all network users, by their combined network usage, would impose in the (very) *long term* assuming that the system would operate in perpetuity in a chosen present or future condition, for a specified demand and generation background. The entire network would then be costed at the modern equivalent asset value and the cost of the whole network would then be allocated among the users. This network charging approach is based on a green field network planning exercise that ignores the capacity of the existing network.

b. **Dynamic Model**: Alternatively network pricing methodology could be concerned only with *future reinforcement costs* (incremental investment) that are considered to be required given forecasts of future developments in generation (commissioning of new or decommissioning of old plant) and growth in demand. In this approach, the network evolves from its present state, with its existing capacity over a specific time horizon in future (this time horizon will be a parameter of the methodology). The timing of future reinforcements of individual network circuits is recorded and then Net Present Value of all individual circuit reinforcements is calculated and these *future* reinforcement costs are then allocated to the users in different locations. The unused capacity or headroom of an asset will be important when determining the point in time in future when reinforcement is required (the larger the headroom, the further into the future reinforcement will be required).

5.3.3. Marginal versus Average Cost

Pricing methodologies can allocate marginal investment cost or average investment costs. Both of these approaches can be applied to the two network costing concepts above.

(i) Charging based on Marginal Investment costs: in this case charges are equal to the theoretical shadow price of the investment costs, defined in terms of infinitely divisible investment costs driven by vanishingly small increments of load or generation at a particular location. This is consistent with the pure economic theory of pricing, assuming that the network investment costs follow continuous monotonically increasing constant functions. When this method is applied, some form of revenue reconciliation is normally required to meet the revenue adequacy requirements.

(ii) In practice, physical units of transmission assets are discrete, as corresponding future investments come in blocks and application of pure marginal costs may be difficult when costing model (a) from the above is used. Instead of using theoretical vanishingly small increments, it is possible to use increments that are representative of the sizes of actual assets, e.g. several hundreds of MWs. This would closely represent average costs and in this situation all costs of building circuits would be 100% locational. The methodology that is concerned with future reinforcement costs (model (b) above) can inherently deal with lumpy investments.

5.3.4. Revenue Reconciliation

An economically optimal transmission network pricing methodology may not meet revenue adequacy constraints and some level of revenue reconciliation may be an important and inescapable aspect of transmission pricing. Some of the main reasons that render achievement of optimal networks difficult in practice are: lumpiness of transmission investment, economies of scale, overhead line and cable conductor sizes come in standard sizes, uncertainties in generation and demand levels and the need to recover certain cost elements associated with the operation and management of transmission systems that are independent of network capacity. When conducting revenue reconciliation, the target is generally to achieve approved revenue targets with as little impact as possible on economic signals. Some general methodologies for solving this problem, such as Ramsey pricing, are discussed in economic literature. One of the issues associated with such methods is the tendency to increase charges to those users who are least sensitive to price, in order to achieve revenue targets. Another approach is to use scaling factors (multiplicative or additive) to adjust the charges to meet revenue requirements. In order to maintain the locational price differential, evaluated though marginal investment costs, the shortfall (residual) is recovered through imposing additional non-locational charges (which can be energy or peak demand based). In the process of revenue reconciliation, adjustments could be made to the ratio between demand and generation contributions to the total network costs.

5.4. Legacy Issues

There are a number of legacy issues that exist in both jurisdictions, which, while not boundary conditions, still need to be taken into account and possibly reviewed when devising new arrangements. Examples of these include:

1. The transition from deep connection charging policy to shallow connection charging in Northern Ireland. Users that connected in NI prior to the establishment of the SEM paid for deep reinforcements however users in ROI paid only for shallow connection charges while the additional deep reinforcement costs are recovered via TUoS revenue;
2. Arrangements such as the pre-existing Power Procurement Business (PPB) contracts in Northern Ireland, or other similar contracts that exist, which influence how generator TUoS costs can be passed on to demand customers;
3. All embedded generators connected in ROI before 19th of February 2000 have a TLAF of 1 as directed by CER;

4. Under current arrangements all embedded generators with a Maximum Export Capacity of less than 10MW have a zero rate TUoS charge;
5. Wind generators and any temporary generator connected to the system have a lower tariff limit of zero which means that these units cannot have a negative tariff and hence receive TUoS payments;
6. The tariff methodology adopted must allow for any arrangements that exist to facilitate non-firm access to the system; and
7. Cross subsidisation of demand customers should be avoided. This could possibly occur given the different connection charging policies for demand users in NI and ROI. (Currently demand users pay 50% shallow connection charges in Republic of Ireland (ROI) and the remainder is recovered via TUoS charges. Demand users connecting in Northern Ireland pay 100% shallow connection charges).

5.5. Feedback from Industry

The Questionnaire, Workshop and Industry Paper document which was published at the start of May outlines the feedback which was given by the Electricity Industry on the subject of the review. A number of trends and themes were noted in the responses all of which have been taken into consideration when deciding on the design objectives of any methodologies that will be implemented (See Section 3).

A number of participants have referred to the need for further transparency in how TUoS and TLAFs are calculated. This is in order to be able to replicate the studies to assist in forecasting further charges and costs. Other respondents simply called for indicative charges and costs to be outlined for a three year period. During the design phase the project team will examine the possibility of providing indicative TUoS charges and TLAFs for a number of years (which would remain subject to change). This may help bring about the transparency needed by Industry Participants.

A number of industry participants have suggested that Cost Benefit Analysis be done on various methodologies to ensure that any benefit outweighs the potential cost of implementation and use. It has also been suggested that volatility and other factors be taken into account in any Cost Benefit Analysis i.e. do the benefits outweigh the costs associated with transmission locational signals.

There were conflicting responses in a number of areas (e.g. the significance of TUoS and TLAFs in making investment decisions) however, where possible as many main viewpoints will be taken into account during the next phase of the project.

5.6. Choice of Model Options

Having reviewed various international tariff models and losses methodologies, the SOs set about determining a list of models which warrant further consideration. Some of the models reviewed, such as Mexico's TUoS tariff regime which employs 81 snapshots and is applied in a spot market, have been deemed inconsistent with the design of the SEM. Therefore, the SOs are not recommending further analysis of this type of pricing model. The SOs felt that a small number of models could be adapted in some way so as to be applicable to SEM in order to recover the transmission required revenue and the cost of transmission losses. Some electricity markets have been found to employ similar approaches to one another. Hence, in some cases, one option encapsulates a number of countries together.

Following a High-Level investigation of alternative models, the SOs have presented those options which the SOs believe are worthy of further investigation. At this stage, it is not possible to put forward a preferred model, nor is it the SOs wish to do so. The SOs anticipate that based on the various options set out in Sections 6 and 7 of this document, participants will be able to assess the options and corresponding pros and cons of each and relate back with views on each of the models, so that these can be considered in determining which models should be analysed further. It is important that models are viewed in terms of the principle objectives which have been set for the TUoS and Losses approaches. Following on from this, any model deemed worthy of further consideration will be progressed in the design stage of the project. It will not be possible to reintroduce any model which is discounted in the investigation stage of the project, so it is vital that participants given full consideration to each of the options outlined and relate their views and supporting reasons for any recommendations back to the SOs.

6. Losses Options

This section presents four alternative losses methodologies which participants should consider with a view to determining if each of these would be considered appropriate for Ireland and Northern Ireland. The four options are as follows:

1. Loss Adjustment Factors (6.1)
2. Uniform Loss Adjustment Factors (6.2)
3. Zonal Loss Adjustment factors (6.3)
4. Purchase of Losses (6.4)

Different users of the network, depending on their location and operating patterns, will have different impacts on network losses. The contribution that an individual network user makes to network losses is usually measured through the change in total system losses as a consequence of change in power injection at the appropriate location. Given that the losses are a quadratic function of the power flow (which is broadly linear with respect to nodal injections), allocation of losses using efficient (marginal) cost pricing principles would lead to over recovery. Hence, marginal loss adjustment factors are usually scaled down (for about 50%) and allocation of losses hence follows average rather than marginal pricing philosophy.

6.1. Loss Adjustment Factors

Transmission Loss Adjustment Factors, which are calculated using Marginal Loss Factors (MLFs), are derived for each generator, taking account of forecast assumptions of average system demand and average generation dispatch and time of the year (month) and day (daytime and night-time). This approach is used in both jurisdictions on the island of Ireland. For a particular load and generation dispatch scenario, the MLF of a generator can be defined as the ratio of the change in system losses to the change in generation of the generator.

EirGrid and SONI’s current approach to TLAF derivation involves the use of power flow modelling software for marginal loss studies for each generator in the Single Electricity Market (SEM) accessing the market. EirGrid and

SONI develops a number of study cases that represent real system conditions and dispatch.

The losses allocated by MLFs are higher than base-case (or average) losses. This results in a requirement for scaling of marginal loss factors to ensure that only the base-case losses, as determined by separate studies in our power flow modelling software, are allocated to users. The MLFs derived for each generator are scaled uniformly using a shift [delta], or subtractive, approach so that the apportionment (generator output multiplied by the loss factor) meets the base-case losses. This is performed for each applicable case (i.e. day and night for each month). The overall loss allocation for each representative case (losses multiplied by case hours) is summed to determine whether the total allocated losses meet the forecast of overall system losses for the year. These factors are then scaled again using the shift method, to ensure the final apportionment (forecast generator output multiplied by the TLAFs) exactly recovers the annual forecast of transmission system losses.

Outlined below in Table 3, are the key aspects of the method that both the Republic of Ireland and Northern Ireland employ in utilising loss adjustment factors to incorporate the cost of losses.

Table 3: Loss Adjustment methodology currently applied in ROI & NI

Loss Adjustment Factors	
Location Vs Uniform	Losses factors are allocated to each node.
Purchase Vs Loss Adjusted	Loss adjusted. These loss factors in conjunction with bid price determine whether the bid is selected for dispatch.
Demand / Generation split	TLAF apply only to Generators
Fixed / Non-fixed	Not Appliacble. (All losses recovered)
Ex-ante / Ex-post	The loss factors are forecast on annual ex-ante basis.
Single / Multi-part	Each month participants are allocated different loss factors. There are different factors for day and night.
Dispatch (treatment of wind and interconnection)	The use of loss factors should lead to an efficient dispatch. At present the dispatch is calculated using Plexus market modelling.
Period of Application	The loss factors are established for the forthcoming year.
Marginal Vs Average	They are marginal loss factors.

6.2. Uniform Loss Adjustment Factors

An alternative to providing a nodal loss factor is to use uniform loss adjustment factors. Using uniform loss adjustment factors results in one TLAF being allocated to every participant. Essentially the transmission losses that exist in the network system are allocated on a socialised basis. Individual participant's specific impact on losses is not reflected. Rather it is the aggregate impact of all participants that is reflected. Therefore, uniform losses send a lacklustre signal in terms of the impact that participants have on the system. Furthermore, considering dispatch the use of one TLAF for every participant perhaps may not lead to an efficient dispatch in terms of losses. Uniform losses essentially remove the variable impact that TLAFs can be considered to introduce for individual participants and between participants. The changes in the total network losses would be reflected in the uniform TLAF. With the aggregate nature of the uniform TLAF the variability would be expected to be minimal. A uniform loss factor does not send either a short term or long term transmission locational signal to participants regarding the losses associated with their location. A uniform loss adjustment approach would not be compatible with the June 2005 SEM High-Level Design.

Table 4: Uniform Loss Adjustment Factors

Uniform Loss Adjustment Factors	
Location Vs Uniform	Loss factors are allocated on uniform basis. Every participant receives the same loss factor.
Purchase Vs Loss Adjusted	Loss adjusted.
Demand / Generation split	This is a parameter that can be altered and decided at a later stage.
Fixed / Non-fixed	All losses recovered uniformly
Ex-ante / Ex-post*	The loss factors are forecast on annual ex-ante basis.
Single / Multi-part	The methodology can be adapted to include a single loss factor or a multi-part loss factor e.g. different loss factors for each season.
Dispatch (treatment of wind and interconnection)	The use of uniform loss factors may not lead to an efficient dispatch in terms of losses.
Period of Application	The loss factors are established for the forthcoming year.
Marginal Vs Average	They are average loss factors.
Implementation date	Post Q4 2010

* In Great Britain metered energy losses are measured ex-post. However, to use such an approach on an all-island basis would require considerable

infrastructure investment which would mean that its implementation would be beyond the timeframe of this project.

6.3. Zonal Losses Adjustment Factors

A further option is to allocate losses on a zonal basis. Zonal transmission loss factors are derived from dispatch and system modelling, similar to the current TLAF approach. Participants within the same zone receive the same loss factor. The intention of zonal transmission losses is to attempt to send long-term transmission locational signals regarding losses. It has the potential to send significant information to users regarding the implications associated with locating in a certain area and support a reduction in the total amount of electricity transmitted and therefore increase the efficient use of energy. Its signal has the possible potential to be relatively consistent over time because it is incorporating an aggregate number of nodal loss factors into one loss factor.

While a zonal loss factor does not reflect the losses from specific nodal locations it is more reflective than uniform losses. In terms of efficient dispatch and other considerations (see objectives), there is a trade-off to be made between the costs and benefits of nodal loss factors and uniform losses which needs to be managed. It is in this management of this trade-off were zonal losses may prove to be an appropriate solution. A further important decision that needs to be considered regarding zonal losses is determining the area that the zones cover. This requires extensive and comprehensive analysis. The areas selected and the impact of such a selection will feed into the management of the above mentioned trade-off.

Table 5: Zonal Loss Adjustment Factors

Zonal Loss Adjustment Factors	
Location Vs Uniform	Loss factors are allocated to each node. The nodal loss factors are then grouped into a zone. All participants within a zone receive the same zonal loss factor.
Purchase Vs Loss Adjusted	Loss adjusted. These zonal loss factors in conjunction with bid price determine whether the bid is selected for dispatch.
Demand / Generation split	This is a parameter that can be altered and decided at a later stage.
Fixed / Non-fixed	Can be set to recover only non-fixed losses and then fixed losses may be recovered uniformly or could recover all technical losses.
Ex-ante / Ex-post	The loss factors are forecast on annual ex-ante basis.
Single / Multi-part	The methodology can be adapted to include a single loss factor or a multi-part loss factor e.g. different loss factors for each season.
Dispatch (treatment of wind and interconnection)	The use of loss factors should lead to an efficient dispatch. However, the use of zonal loss factors may introduce a trade-off to this efficiency.

Zonal Loss Adjustment Factors	
Period of Application	The loss factors are established for the forthcoming year.
Marginal Vs Average	They are marginal loss factors.
Implementation date	Q4 2010

6.4. Purchase of Losses

The purchase of losses is an alternative to applying loss factors to the price in bids and market schedule quantity in settlement. Losses result in a misalignment in the market between what has been produced by generators and what is being consumed by demand. One method of overcoming this misalignment is for the TSO to purchase these losses. In other words, the TSO buys at the system marginal price the unit (MW) gap between what has been produced and consumed.

While the purchase of losses methodology is used widely in other countries (Nordic countries for example) it does not fit with the design of the SEM market. Its use would also require considerable infrastructure investment which would mean that its implementation would be beyond the timeframe of this project.

Table 6: Purchase of Losses Characteristics

Purchase of Losses	
Location Vs Uniform	The cost of losses can be either charged on a locational (nodal) basis or a uniform basis.

Purchase of Losses	
Purchase Vs Loss Adjusted	TSO purchases the losses. The cost of this is then reflected in the tariff charge.
Purchase Vs Loss Adjusted (continued)	If the charge is locational a loss factor is typically utilised to allocate the cost of the losses to participants in the tariff (e.g. marginal loss rate). The uniform charge does not require loss factors to differentiate the charge between participants.
Demand / Generation split	If the charge is locational the net consumption / production at a node determines the allocation of the cost of losses. The uniform charge can be adjusted to represent any particular demand / generation split.
Fixed / Non-fixed	Can be used for either.
Ex-ante / Ex-post	If locational, it is charged as incurred. However, the loss factors are forecast ex-ante. If uniform, the charges can be forecast ex-ante. Note in both cases the tariff can be

Purchase of Losses	
	adjusted ex-post if there is over/under recovery of the tariff revenue requirement.
Single / Multi-part	A number of different methods are appropriate if charges are locational.
Dispatch (treatment of wind and interconnection)	The locational charge should lead to a more efficient dispatch. The uniform charge will not lead to an efficient dispatch.
Period of Application	A number of different methods are appropriate.
Marginal Vs Average	Typically any forecast for a loss rate is based on a marginal loss rate. It is also possible to apply an average loss rate instead. It is not applicable to a uniform charge.
Incumbent Vs New entrant	No difference in cost of losses between participants.
Implementation Date	Post Q4 2010.

7. Tariff Options

This section of the document outlines six potential tariff methodologies, which participants should consider with a view to whether these would be deemed acceptable for Ireland and Northern Ireland. It is envisaged that the methodologies outlined would apply to both Generation and Supplier TUoS tariffs unless stated otherwise. The six options are as follows:

1. Pure transmission locational signalling Static Model (7.1.1)
2. Pure transmission locational signalling Dynamic model (7.1.2)
3. Transmission locational signalling marginal cost Static model with residual (7.2.1)
4. Transmission locational signalling marginal cost Dynamic model with residual (7.2.2)
5. Postage stamp model (7.3.1)
6. Postage stamp with incentive discount (7.3.2)

Load Flow Analysis

Options 1, 2, 3 and 4 above all require load flow analysis to be carried out. The load flow methodology (or alternatives) has the scope to utilise a number of different dispatch scenarios in its modelling. For example, the current reverse MW mile methodology used in the Republic of Ireland utilises a winter peak scenario in its modelling.

Reverse MW mile

Network costs are allocated using a proportion ratio between power flow and network capacity. It offers a reward for off setting flows and does not recover the cost of spare capacity.

Standard MW mile

Network costs are allocated using a proportion ratio between power flow and network capacity. This method does not provide a reward for off setting flows and does not recover the cost of spare capacity.

Modulus/usage method

This method substitutes the network capacities in the ratio with absolute power flows so that the users pay for the spare capacity of the lines also.

7.1. Pure transmission Locational Signal for Generation and Demand

The aim of a TUoS transmission locational signal methodology is to differentiate the impact that participants have on the transmission network. Every participant influences the network in a unique manner. Transmission locational signals are a means to reflect this uniqueness. When applying locational TUoS tariffs, both generation and demand users should ideally be subject to the locational signal. The two options under examination here allocate TUoS charges on a transmission locational signal basis only.

There are two dominant methods in which transmission locational signals can be developed (see 5.3.2). The Static Model is centred on a fixed development setting for the network. The Dynamic model is focused on forward looking incremental costs. It recognises that determining future network developments is a fluid process which responds to different network requirements as they arise.

In each of the two models below, charges are entirely locational. In a situation where the model does not meet exact revenue requirements in the tariff period, the residual revenue will also be recovered on a locational basis through appropriate scaling of the tariffs.

7.1.1. Pure Transmission Locational Signalling Static Model

This method is consistent with a peak demand driven network planning approach. The locational charges would be based on average investment cost, calculated on the basis of the modern equivalent asset value of the cost of the entire network. In order to achieve pure locational charges, prices would need to be uniformly scaled to meet revenue adequacy requirements. In this model the residual revenue would be recovered on a locational basis.

7.1.2. Pure Transmission Locational Signalling Dynamic Model

The locational charges reflect Net Present Value (NPV) of costs associated with future network reinforcements required as a consequent of a forecasted generation background and evolving demand load growth during a chosen time horizon. Charges could be based on marginal or average incremental investment cost of network reinforcements. Revenue adequacy will be very dependent on the actual loading of the network relative to its capacity (i.e. proximity to reinforcement).

As in Option 7.1.1, in order to achieve pure locational charges, forward costs based prices would need to be uniformly scaled to meet revenue adequacy requirements, the residual revenue would be recovered on a locational basis.

There are numerous alternatives in every design aspect of a locational signalling methodology. Each possibility needs to be considered carefully in the context of the objectives of the project.

Table 7: Pure Location Signalling Static Model

Pure Location Signalling Static Model	
Connection Policy	Shallow.
Locational (incl. load flow) Vs Postage stamp	The tariff will be collected on a transmission locational signal basis. This would typically be based on a load flow methodology.
Energy Vs Capacity	The load flow methodology is based on capacity.
Demand / Generation split	This is a design parameter which can be altered depending on a number of factors e.g. to take external market factors into account.
Costing approach	A single scenario is selected . An optimal network is designed around this scenario. The design approach uses a Modern Equivalent Asset Valuation Approach. An assumption is made that the designed network would operate in perpetuity.
Dispatch / Scenarios (treatment of wind and	The transmission locational signal methodology, e.g. load flow methodology, has the scope to utilise a number of different approaches e.g. a peak winter dispatch scenario.

Pure Location Signalling Static Model	
interconnection)	
Volatility Mitigation Technique	There are no Volatility Mitigation Techniques.
Network Optimisation	The use of a network optimisation technique may be required.
Scaling e.g. Delta multiplier	A scaling method can be applied to the Location Signalling methodology to ensure recovery of the tariff requirement. The scaling would be done to maintain the transmission locational signalling.
Zonal Vs Nodal	The transmission locational signal could be nodal based or zonal.
Asset Included e.g. system support, for instance Capacitor	Model can be designed to include any necessary assets.
Period of Interest	The tariff would apply for the forthcoming year.
Implementation Date	Q4 2010.

Table 8: Pure Location Signalling Dynamic Model

Pure Location Signalling Dynamic Model	
Connection Policy	Shallow.
Locational (incl. load flow) Vs Postage stamp	The tariff will be collected on a transmission locational signal basis. This would typically be based on a load flow methodology.
Energy Vs Capacity	The load flow methodology is based on capacity.
Demand / Generation split	This is a design parameter which can be altered depending on a number of factors e.g. to take external market factors into account.
Costing approach	The future reinforcements are valued at Modern Equivalent Asset value at time 't'. This value is allocated to participants in Net Present Value terms.
Dispatch / Scenarios (treatment of wind and interconnection)	The transmission locational signal methodology, e.g. load flow methodology, has the scope to utilise a number of different approaches e.g. a peak winter dispatch scenario.
Volatility Mitigation Technique	There are no Volatility Mitigation Techniques.

Pure Location Signalling Dynamic Model	
Network Optimisation	The use of a network optimisation technique may be required.
Scaling e.g. Delta multiplier	A scaling method can be applied to the Location Signalling methodology to ensure recovery of the tariff requirement. In this model the scaling would be done on a locational basis.
Zonal Vs Nodal	The transmission locational signal could be nodal or zonal based.
Asset Included e.g. system support, for instance Capacitor	This may form part of the network costing.
Period of Interest	The tariff would apply for the forthcoming year.
Implementation Date	Q4 2010.

7.2. Marginal Investment Cost based pricing (with residual) for Generator & Demand tariffs

A hybrid model will effectively combine a locational tariff element and a postage stamp tariff element in one model in order to achieve the benefits associated with each individual methodology. The principle aim of a hybrid model is to provide a transmission locational signal to participants, reflecting to some degree the cost they impose on the transmission system, whilst also promoting more secure and stable tariffs through the use of a postage stamp component.

In each of the two models below, charges are determined on a locational basis. In a situation where the model does not meet exact revenue requirements in any tariff period the residual revenue will be recovered on a non-locational basis. It is important to note that the model parameters and the network characteristic determine the proportion of revenue that is recovered through the location element of the charge and that this proportion can vary from year to year, although it is normally relatively stable.

7.2.1. Static Model (similar to that applied in Great Britain)

Using the Static model approach it is possible to illustrate an example where marginal network investment cost is applied. In order to maintain the locational price differential evaluated, the residual revenue is recovered through imposing non-location specific charges. These residual charges (postage stamping) are generally peak demand based.

The percentage split of the locational and postage stamp elements of the tariff can vary depending on the particular characteristics of the methodology and the transmission system to which it is applied. A hybrid transmission tariff model is currently applied by National Grid in England, Scotland and Wales. This model recovers approximately 15% of the transmission revenue via a locational tariff and the remaining 85% of revenue through a uniform postage stamp tariff (residual). The model is used to derive both generation and demand tariffs. Further details can be found in Option 9 outlined in the appendix .

7.2.2. Dynamic Model

Marginal prices can also be applied to the dynamic model. The locational charges reflect Net Present Value (NPV) of costs associated with future network reinforcements required as a consequent of a forecasted generation background and evolving demand load growth during a chosen time horizon. Revenue adequacy will be dependent on the actual loading of the network relative to its capacity (i.e. proximity to reinforcement), which shall influence the level and timing of necessary future reinforcements. As in the Static case above, in order to maintain the locational price differential evaluated, residual revenue is recovered through imposing non-location specific charges.

The aim of a TUoS locational tariff component is to differentiate between the impact that participants have on the transmission network. Participants who drive transmission investment or make more use of the system than others will pay higher TUoS tariffs, hence costs are attributed, to some degree, to those responsible for causing them. The residual recovery through a postage stamp tariff component, on the other hand, takes no account of location and simply apportions the required revenue amongst all users of the system in a uniform fashion. The advantage of the postage stamp approach is that resulting tariffs tend to be relatively stable year on year, varying only in response to fluctuations in the revenue requirement or total system capacity or energy forecasts values.

In summary, in terms of deriving the locational tariff component understandably there are different methods that can be employed to determine which participants drive costs and how these costs are measured. Similarly there are different ways to view the network; it could be the existing network at the time of the tariff period that is used or a view of a future network. It is not intended at this stage of the project to dictate which exact locational methodology would be used in the hybrid model or the precise features of it. The aim is merely to illustrate that a combination of the two types of methodologies, as outlined above in 7.1 and 7.2, is a possibility that may meet the objectives of the all-island TUoS tariff regime.

Table 9: Marginal Investment Cost based pricing (with residual) Static Model

Marginal Investment Cost based pricing (with residual) Static Model	
Connection Policy	Shallow.
Locational (incl. load flow) Vs Postage stamp	The tariff will be collected on a locational signal basis. This would typically be based on a load flow methodology. Any tariff component used to collect residual revenue would be calculated on a postage stamp basis.
Energy Vs Capacity	The load flow methodology is based on capacity.
Demand / Generation split	This is a design parameter which can be altered depending on a number of factors e.g. to take external market factors into account.
Costing approach	A single scenario is selected . An optimal network is designed around this scenario. The design approach uses a Modern Equivalent Asset Valuation Approach. An assumption is made that the designed network would operate in perpetuity. To ensure revenue adequacy, a residual element is required i.e. postage stamping.

Marginal Investment Cost based pricing (with residual) Static Model	
Dispatch / Scenarios (treatment of wind and interconnection)	The transmission locational signal methodology,e.g. load flow methodology, has the scope to utilise a number of different approaches e.g. a peak winter dispatch scenario.
Volatility Mitigation Technique	There are no Volatility Mitigation Techniques.
Network Optimisation	The use of a network optimisation technique may be required.
Scaling e.g. Delta multiplier	This is generally not necessary as any over/under recovery is dealt with as residual element.
Zonal Vs Nodal	The transmission locational signal could be nodal or zonal based.
Asset Included e.g. system support, for instance Capacitor	Any assets deemed relevant can be included in the costing of the model.
Period of Interest	The tariff would apply for the forthcoming year.

Marginal Investment Cost based pricing (with residual) Static Model	
Implementation Date	Q4 2010.

Table 10: Marginal Investment Cost based pricing (with residual) Dynamic Model

Marginal Investment Cost based pricing (with residual) Dynamic Model	
Connection Policy	Shallow.
Locational (incl. load flow) Vs Postage stamp	The tariff will be collected on a transmission locational signal basis. This would typically be based on a load flow methodology. Any tariff component used to collect residual revenue would be calculated on a postage stamp basis.
Energy Vs Capacity	The load flow methodology is based on capacity.
Demand / Generation split	This is a design parameter which can be altered depending on a number of factors e.g. to take external market factors into account.
Costing approach	The future reinforcements are valued at Modern Equivalent Asset value at time ‘t’. This value is allocated to participants in Net Present Value terms.
Dispatch / Scenarios (treatment of wind and interconnection)	The transmission locational signal methodology, e.g. load flow methodology, has the scope to utilise a number of different approaches e.g. a peak winter dispatch scenario.

Marginal Investment Cost based pricing (with residual) Dynamic Model	
Volatility Mitigation Technique	There are no Volatility Mitigation Techniques.
Network Optimisation	The use of a network optimisation technique may be required.
Scaling e.g. Delta multiplier	This is generally not necessary as any over/under recovery is dealt with as residual element.
Zonal Vs Nodal	The transmission locational signal could be nodal or zonal based.
Asset Included e.g. system support, for instance Capacitor	This may form part of the network costing.
Period of Interest	The tariff would apply for the forthcoming year.
Implementation Date	Q4 2010.

7.3. Postage Stamping for Generator and Demand TUoS

This section outlines the two varieties of postage stamping that could be applied on an all-island basis.

7.3.1. Pure Postage Stamping for Generator and Demand TUoS

The postage stamping methodology charges the same rate to every participant. This rate can be applied to a firm's capacity (MW), energy usage (MWh) or a combination of both. Therefore, participants are charged a certain rate on the same basis. It does not provide a transmission locational signal. To calculate the rate the TUoS tariff revenue requirement is determined first. This is then divided by the total capacity, energy or combination. It is then allocated on a pro-rata basis.

Furthermore, the rate charged to participants will directly increase/decrease with the revenue requirement and changes in forecast total energy or capacity. The use of postage stamping results in smoothing out of changes in the revenue requirement across all participants. Every participant is effected in the same manner i.e. through the charge rate. The use of a capacity or energy basis may influence participant's behaviour differently. Regarding an energy charge, participants short term actions will impact how much they pay. Utilising the capacity charge, it will take longer for participants' actions to impact the amount of the TUoS that they pay.

It should be noted that under/over recovery of the TUoS tariff revenue requirement would be brought forward to the next tariff period. The use of a pure Postage Stamp approach would not be compatible with the June 2005 SEM High Level design.

Table 11: Pure Postage Stamp Model

Pure Postage Stamping Option TUoS Tariff	
Connection Policy	Shallow.
Locational (incl. load flow) Vs Postage stamp	Postage Stamp. There is a uniform rate charged to every participant. The charges can be allocated on either a capacity, energy or a combination basis.
Energy Vs Capacity	The postage stamp method has scope for either basis to apply.
Demand / Generation split	This is a design parameter which can be altered depending on a number of factors e.g. to take external market factors into account.
Costing approach	Network costing is not needed in the methodology as a postage stamp approach is used.
Dispatch / Scenarios (treatment of wind and interconnection)	This is not relevant to the methodology as a postage stamp approach is used.
Volatility Mitigation Technique	There are no Volatility Mitigation Techniques.
Network Optimisation	It is not applicable because there is no costing of the network due to the use of a postage stamp methodology.

Pure Postage Stamping Option TUoS Tariff	
Scaling e.g. Delta multiplier	It is not applicable because the tariff is a postage stamp method. However, the tariff can be adjusted ex-post to reflect under/over recovery.
Zonal Vs Nodal	This is not relevant to the methodology as a postage stamp approach is used. It is the same fee rate for every participant.
Asset Included e.g. system support, for instance Capacitor	This information is not relevant to the methodology as a postage stamp approach is used.
Period of Interest	The tariff would apply for the forthcoming year.
Implementation Date	Q4 2010.

7.3.2. Postage Stamp with Incentive Discount for Generation & Demand (similar to that applied in Norway)

This option makes adjustments to the "Postage Stamp" option. While it is broadly similar it introduces an important concept. It offers the system operators the flexibility to provide a discount to the TUoS tariff to participants that locate in an area that is considered favourable to the performance of the transmission network. Therefore, this discount is in effect providing a transmission locational signal.

The postage stamp element is not providing a locational signal. It is allocating a set rate to every participant. This set rate can then be applied to participants on a capacity (MW), energy usage (MWh) or a combination basis.

Essentially the system operator selects a number of areas where the introduction of a generator or demand participant will improve performance of the network. This is done on an annual basis. To determine favourable areas the SO would run studies for a given area that compares the introduction of a generator/demand participant to developing the network in terms of reliability standards and economic value. If the analysis determines that the introduction of a participant would bring net benefits (i.e. provides better value than developing the network) then an appropriate figure would be determined for the discount to incentivise the introduction of the participant. The upper boundary of this discount would be the value placed on the benefits that the participant would deliver. The availability of the discount would be limited to a certain capacity or energy level for a given area.

The participant will not know exactly what his charge will be going forward but it will have certainty that its charge will be lower compared to other units who have not chosen a "favourable" location.

If, say, in another three years a second participant comes along and wishes to connect to that same location, the location may no longer be deemed as a "favourable" location therefore no discount would be offered to the new generator.

The new unit may however still decide to locate on the site, but he has the advance knowledge that his TUoS costs will be higher than if it was to select a different site where the TSO deems as favourable. The connection of an additional unit has no impact on the TUoS costs of the original unit who chose the location when it was a favourable location. The original unit will have a lower TUoS tariff than the new unit who has sited close by.

There are a number of complex decisions that would be required to implement such a proposal:

- How all units already connected to the transmission system at the implementation of this methodology would be treated given that their location has already been decided;
- What criteria the SOs would use to determine "favourable sites"; and
- What level of discount is offered and how the discount is applied, i.e is it a percentage reduction or a nominal reduction on future TUoS tariffs?

Since this is a new option, not commonly implemented as a TUoS methodology elsewhere, extensive consideration and detailed analysis would be required to determine if this type of model is feasible for determining TUoS in the all-island market.

Table 12: Postage Stamping with Incentive Discount Option

Postage Stamping with Incentive Discount Option	
Connection Policy	Shallow.
Locational (incl. load flow) Vs Postage stamp	Postage Stamp combined with a tariff discount to favourable locations. This discount provides a transmission locational signal. With the postage stamp element there is a uniform rate charged to every participant. The charges can be allocated on either a capacity, energy or a combination basis. The discount can be offered to either generation or demand if they locate in an area that is favourable to the grid, as determined by the system operator. The discount can take the form of a set nominal reduction or a percentage reduction to an applicable participant. The discount may be given to an applicable participant for certain period of time e.g. 15 years.
Energy Vs Capacity	The postage stamp method has scope for either basis to apply.
Demand / Generation split	This is a design parameter which can be altered depending on a number of factors e.g. to take external market factors into account.
Costing approach	Network costing is not needed in the methodology as a postage stamp approach is used.

Postage Stamping with Incentive Discount Option	
Dispatch / Scenarios	This is not relevant to the methodology as a postage stamp approach is used. May need to consider dispatch scenarios for determining if an incentive discount should be applied.
Volatility Mitigation Technique	There are no Volatility Mitigation Techniques.
Network Optimisation	It is not applicable because there is no costing of the network due to the use of a postage stamp methodology.
Scaling e.g. Delta multiplier	It is not applicable because the tariff is a postage stamp method.
Zonal Vs Nodal	This is not relevant to the postage stamp methodology. It is the same flat rate for every participant. The discount will be offered to certain areas i.e. zonal.
Asset Included e.g. system support, for instance Capacitor	This information is not relevant to the methodology as a postage stamp approach is used.
Period of Interest	The tariff would apply for the forthcoming year.
Implementation Date	Q4 2010.

8. Comparison of Options

8.1. Comparison of Tariff Options

The table below provides a correlation index of all six options described in Section 7 against each of the objectives outlined in Section 3. While the assessment is somewhat subjective, it is anticipated that there will be general agreement on how each option correlates. H indicates a High Correlation, M indicates a Medium Correlation and L indicates a Low Correlation between the particular model and the objective.

Table 13: Comparison of TUoS Options

	Cost Reflective	Efficient future investment planning	Transparent	Predictable	Non Volatile	Consistent between generator & demand customer
Pure Transmission locational signalling Static Model	M	M	M	M	L	H
Pure Transmission locational signalling Dynamic Model	H	H	M	M	L	H

Marginal Investment Cost Based Pricing (with Residual) Static Model	M	M	M	M	M	H
Marginal Investment Cost Based Pricing (with Residual) Dynamic Model	M	M	M	M	M	H
Postage Stamping	L	L	M	H	H	H
Postage Stamping with Incentive Discount	M	L	M	H	H	H

8.2. Comparison of Losses

Table 12 below provides a correlation index of all four options described in Section 6 against each of the objectives outlined in Section 3. As above H indicates a High Correlation, M indicates a Medium Correlation and L indicates a Low Correlation between the particular losses approach and the objectives.

Table 14: Comparison of Losses Options

	Cost Reflective	Transparent	Predictable	Non Volatile	Efficient in the short term (Efficient Dispatch)	Consistent between generator & demand customer
Uniform Losses	L	M	H	H	L	NA
Loss Adjust. Factors	H	M	L	L	H	NA
Zonal Losses	M	M	H	H	M	NA
Purchase & Social. of losses	L	H	H	H	L	H

9. Next Steps

1. **Consult on the options:**

Based on the feedback from the Industry it has been decided to have a longer consultation on this Option paper than previously anticipated. This consultation on this Paper will last for approximately 6 weeks from the date of publication and will include a workshop on June 16^{th}. The closing date for the consultation is Friday July 10^{th} at 17:00.

2. **Carry out a number of simulations and studies on all 6 options:**

A number of studies will be carried out during the design phase to determine which of the options identified best achieves the objectives outlined in Section 3. These studies will address some of the issues raised by the Industry during the Investigation Phase. Note that it may be desirable to use a variation of one of the Options in the final proposal for practical reasons.

3. **Produce indicative tariffs etc:**

There will be a number of outputs from the Design phase. The first of these will be the description of a preferred option. Other outputs will include indicative tariffs and losses figures (if appropriate) which will be shared with the industry at a later stage.

4. **Decide on preferred option and consult:**

The outputs of the preferred options will form the basis of a consultation, which will most likely take place in Q3 2009.

5. **Identify a schedule for implementation:**

The time needed to consult adequately means that certain timeframes, which were discussed at the preliminary stages of the project may be subject to change. Depending on the complexity of the options being proposed, the schedule for implementation will last from 6 to 12 months.

6. **Implement the arrangement:**

The new arrangements will have an impact on a number of business processes in the System Operators businesses. This will mean varying degrees of development on billing solutions and other tools which are affected by changes.

It is intended to have the implementation phase completed in order to begin using the new arrangements in Q4 2010.

Appendix

1. Danish energy industry

Denmark is separated into two regions from a transmission perspective. There is Denmark East and Denmark West. The transmission grid found in the West consists of ring connections while the grid in the East has a radial structure. Both systems are currently unconnected. However, a decision has been made to connect the regions with a DC interconnector.
Both the East and the West are part of Nord pool electricity market.

Energinet.dk is a state-owned independent transmission company for both East and West. Therefore, it acts as both a system operator and transmission asset owner it is responsible for both electricity and gas transmission. It is a not-for-profit organisation. The company was formed after a merger between Eltra, Elkraft System, Elkraft Transmission and Gastra in 2005. While it owns the gas transmission grid and the 400 kV electricity transmission grid, it is not the owner of the 132 kV and 150 kV grids.

Denmark has an installed capacity of approximately 13,000 MW. Approximately 23% or 3,000 MW is wind generation.

Danish Tariff Regime

Both the cost of losses and TUoS is included in its tariff regime. The tariff is divided into three segments: Grid Tariff, System Tariff and a Public Service Obligation Tariff (PSO). Aspects of the costs that both the Grid and System Tariffs account for are equivalent to the TUoS. Additionally, the System Tariff also incorporates the cost of losses. The cost of losses section below will discuss in greater detail the methodology behind the losses. The PSO covers the cost subsidies for environmentally friendly energy production and also supports research and development in this area.

TUoS

A postage stamp method is used for the three tariff segments. A set fee is derived and charged on a firm's kWh energy usage over a period. Each tariff segment revenue requirement is simply divided by the total load to acquire the set fee per kWh, which is calculated on a yearly basis for both the Grid and System Tariff. The PSO fee is determined every quarter. The tariffs are adjusted ex-post to reflect any over/under recovery in the tariff requirement. 98% of the tariff is charged to demand customers, while 2% is charged to generators. The Grid tariff is quite stable annually. However, both the System and PSO tariffs can be volatile because they are more dependent on the system marginal price from the Nord pool.

Cost of Losses

Energinet.dk purchases the losses in the Nord Pool. The cost of purchasing losses is charged through the System Tariff and can be characterized as a uniform cost for losses. That is to say, participants pay a certain rate per kWh, irrespective of the amount of losses at a location. The cost of the losses is forecast ex-ante, on a yearly basis, and is adjusted ex-post to ensure that the tariff captures the actual cost of purchasing the losses.

Danish TUoS Tariff (includes the cost of losses)	
Connection Policy	Shallow.
Locational (incl. load flow) Vs Postage stamp	A form of Postage Stamp is used. It is allocated based on a firm's kWh over the period. Effectively it is based on a firm's gross consumption over the period. There are 3 tariffs • Grid Tariff = calculated per year. • System Tariff = calculated per year. • PSO Tariff = calculated per quarter. There is no time difference in the allocation of the tariff. It is the same rate across all time bands. The tariffs are adjusted ex-post to account for any over/under recovery in the tariff requirement.
Energy Vs Capacity	It is energy based. Tariff paid by each customer is based on their kWh.
Demand / Generation split	98% = Demand 2% = Generators
Costing Approach	Not Applicable Each tariff category revenue requirement is simply divided by the total load to get the DKK/kWh rate.

Danish TUoS Tariff (includes the cost of losses)	
Dispatch / Scenarios (treatment of wind and interconnection)	This is not relevant to the methodology as a postage stamp approach is used.
Volatility Mitigation Technique	Volatility Mitigation Technique’s are not used.
Network Optimisation	No.
Scaling e.g. delta multiplier	No.
Zonal Vs Nodal	Tariff utilises a postage stamp methodology. There are different tariff rates for the East and the West , due to different cost basis.
Asset included e.g. system support, for instance capacitor	Not Applicable
Period of interest	Tariff is calculated on a yearly basis. The PSO segment of tariff is done on a quarterly basis.
Implementation Date	Difficult to determine because purchasing losses is very different to current all-island approach.

Table 15: Danish Tariffs

Danish Losses	
Location Vs Uniform	Uniform. Participants pay a certain rate per kWh. There is system tariff which captures the cost of losses.
Purchase Vs Loss Adjusted	The TSO purchases the losses. The cost of this is then reflected in the tariff charge.
Demand / Generation split	This information is not available for the split in the cost of losses.
Fixed / Non-fixed	Not Applicable
Ex-ante/ Ex-post	Ex-ante. Forecast losses are included as part of the system tariff and the system tariff is set for the forthcoming year.
Single / Multi-part	There is a single charge per kWh.
Dispatch (treatment of wind and interconnection)	Not applicable because of postage stamp method of paying for losses.
Period of Application	The system tariff (which includes losses) is set for each year.

Danish Losses	
Marginal Vs Average	Not applicable because of postage stamp method of paying for losses.
Incumbent Vs New Entrant	No difference in cost of losses between participants.
Implementation Date	Difficult to determine because purchasing losses is very different to current all-island approach.

Table 16: Danish losses

2. Finnish Energy Industry

Finland has a highly interconnected network. It is part of the Nord pool energy market. It is also connected with Russia and Estonia. Fingrid is the independent transmission system operator – it owns (nearly 100%) and operates the 220 kV and 400kV national transmission grid. It is publicly limited company. The Finnish state owns 12% of the company. The rest of the company is privately owned.

Nord Pool Spot is cleared at a system price (unconstrained price) but participants in fact pay an area price (constrained price). In this current period the whole of Finland is considered one zone.

Finland has 16,000 MW of installed capacity. Its generation portfolio consists of 11,137 MW thermal power, 3,031 MW of hydro-electric power, 2,651 MW of Nuclear power and 81 MW of wind[4]. Finland also imports a substantial amount of energy, typically in the region of 10-20%[5].

TUoS

The Finish tariff includes both the cost of TUoS and losses. The tariff is set for a four year period. The current tariff period began in 2008 and will run to 2011. There is a shallow connection policy in place. It can be a deep connection policy in exceptional cases.

The TUoS tariff is allocated on a postage stamp basis. There are three categories of fees. The Consumption fee recoups the cost of the consumption of energy beyond a customer's connection point between the

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[4] Nordel Annual Statistics 2007

[5] Landstedt, J. and Holstrom, P., 2007 Electric Power Systems Blackouts and the Rescue Services: the Case of Finland, Working Paper, Civpro, Civil Protection Network.

customer and Fingrid. There is a set fee per MWh. This fee varies from summer to winter.

The second category, Use of Grid fee, covers the cost of either energy input or output transmitted through a connection point. This is based on a set fee per MWh. Thirdly, there is a connection point fee for being physically connected. It is a set monthly fee for every participant. Demand pay 88% of the tariff and generators pay 12%.

Cost of Losses

Fingrid purchase the losses in the Nord Pool energy market. The cost of these purchases is reflected in the tariff. As noted above the tariff utilises a postage stamp methodology, therefore the cost of losses are allocated on uniform basis i.e. non-locational. In order to be consistent with arranging the tariff rate for a number of years Fingrid begin hedging the risk of price change in the cost of losses five years in advance of the year in question. The hedging portfolio is adjusted between years and during a year to account for changes in the forecast. According to Fingrid transmission losses in Finland are low by international standards indicating high levels of operational efficiency.

Finnish TUoS Tariff (includes the cost of losses)	
Connection Policy	Shallow but can be Deep in exceptional cases.
Locational (incl. load flow) Vs Postage stamp	Postage Stamp. There are three grid service fees. Both generators and demand pay these fees. Consumption fee = covers the cost of the consumption of energy beyond the connection point between the customer and FinGrid. It is a per MWh fee. Different fee rates are utilised for winter and summer. Use of Grid fee = this concerns the volume of energy, either input or output, transmitted through the customer's connection point. It is a per MWh fee. Connection point fee = a set fee of €1,000 per month per physical connection.
Energy Vs Capacity	It is energy based. Tariff paid by each customer is based on their MWh.
Demand / Generation split	Based on total tariff 88% = demand 12% = generators
Costing approach	Network costing is not needed in the methodology as a postage stamp approach is used.
Dispatch / Scenarios (treatment of wind and interconnection)	This is not relevant to the methodology as a postage stamp approach is used.

Finnish TUoS Tariff (includes the cost of losses)	
Volatility Mitigation Technique	There are no Volatility Mitigation Techniques.
Network Optimisation	It is not applicable because there is no costing of the network due to the use of a postage stamp methodology.
Scaling e.g. Delta multiplier	It is not applicable because the tariff is a postage stamp method.
Zonal Vs Nodal	This is not relevant to the methodology as a postage stamp approach is used. It is the same fee rate for every participant.
Asset Included e.g. system support, for instance Capacitor	This information is not relevant to the methodology as a postage stamp approach is used.
Period of Interest	The tariff requirement and thus the unit price per MWh for each fee category are set for the period 2008 to 2011. They may be adjusted annually to reflect the difference in the actual cost and the forecast cost.
Implementation Date	Difficult to determine because purchasing losses is very different to current all-island approach.

Table 17: Finnish Tariffs

Table 18: Finland Losses

Finnish Losses	
Location Vs Uniform	Uniform. Losses are accounted for in the postage stamp tariff.
Purchase Vs Loss Adjusted	The TSO purchases the losses. The cost of this is then reflected in the tariff charge.
Demand / Generation split	This information is not available for the split in the cost of losses.
Fixed / Non-fixed	Not Applicable.
Ex-ante/ Ex-post	Ex-ante. It is included in the tariff.
Single / Multi-part	Different tariff categories can have multi-parts e.g. consumption fee has a winter and summer rate.
Dispatch (treatment of wind and interconnection)	There is no information available regarding the losses component of the tariff.
Period of Application	Tariffs are set for the 2008-2011 period. The tariff may be adjusted annually to reflect changes in the actual cost of losses from the forecast cost of losses.

Finnish Losses	
Marginal Vs average	Not applicable due to postage stamp method of paying for losses.
Incumbent Vs New entrant	No difference in cost of losses between participants.
Implementation Date	Difficult to determine because purchasing losses is very different to current all-island approach.

3. ISO New England energy industry

ISO New England is a regional transmission system operator (RTO). It does not own any transmission assets. It operates the transmission grid on behalf of the transmission owners. The firm operates in the following states; Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. ISO New England operates over 8,000 miles of transmission lines. The region has 13 interconnectors with New York and Canada. There are approximately 900 node locations.

The region has approximately 32,000 MW of capacity (including 2,000 megawatts of demand-response capacity). The load is generated by: 29.1% Gas, 27% Nuclear, 11% Coal, 7.7% Hydro electric power, other renewable accounts for 0.3% and approximately 25% other.

The highest demand for energy occurs in the summer. Peak demand on a normal summer day usually ranges from 19,000 MW to 24,000 MW. This is in contrast to the peak demand in the winter, when the typical range is from 18,000 MW to 20,000 MW. The spring and fall peak demand ranges from 15,000 MW to 18,000 MW. The region has recently seen the summer peak demand rising by approximately 400 MW a year. This of course may change with recent economic conditions.

ISO New England also operates a pool energy market. The pool energy market is based on the energy market operated by PJM. Each generator receives a locational marginal price. This is calculated at each node. It incorporates the system price, cost of constraints and the cost of losses. Demand customers pay a zonal price. The zones broadly follow the boundaries of the states; except that Massachusetts is subdivided into three zones. A zonal price is based on the weighted average of all nodal locational marginal prices in a zone.

TUoS Tariff

The TUoS tariff is divided into two categories. There is the Pool Transmission Facility (PTF) charge and also the Regional Network Service (RNS) charge. The PTF charge recoups a Pool Transmission Owner's (PTO) revenue requirements. This includes Annual Transmission Revenue (e.g. PTO rate of return on assets and expenses), Forecasted Transmission Revenue and Annual True-ups e.g. accounting for over/under recovery. To calculate the PTF charge the sum of the PTO's revenue requirements is divided by the sum of all PTO's monthly peaks. This rate is then allocated on an hourly basis. Every participant is charged the same hourly rate regardless of the amount of energy they utilise during the hour. A discount to the PTF can be offered by PTO's. This offer must be made public and available to all participants connected to the line in question (subject to constraints). Perhaps this discount could be utilised to provide a transmission locational signal.

The second category is the RNS charge. This is an energy based charge. There is currently a pool rate set and also a local RNS. The local RNS is converging towards the pool RNS rate. The RNS covers costs not recovered through the PTF. It is a monthly charge. The RNS rate is a $ rate per kWh. The RNS rate is multiplied by a participants monthly network load. A participant's monthly network load is recorded at the hour when the aggregate load is at its peak in the network.

Cost of losses

The cost of losses is allocated on a locational basis. Each node on the grid is allocated a loss factor. This loss factor reflects the change in losses for every change in the level of MW output. It is a marginal loss factor. It is measured dynamically. A loss factor is calculated for every trading period. The 'real-time market' has five minute periods while the 'day ahead' market has daily periods.

The cost of losses increases a generators bid price and thus increase the system marginal price. The locational marginal price the generator receives incorporates the cost of losses. The dispatch selected by the RTO is determined by the combination of the system marginal price and the loss adjusted quantity supplied by the generator. Note that Financial Transmission Rights are used to hedge against the risk of constraint costs varying.

ISO New England TUoS Tariff	
Connection Policy	Deep connection.
Locational (incl. load flow) Vs Postage stamp	They utilise a postage stamp methodology. There are two categories. Pool Transmission Facility = Pool Transmission Owner (PTO) payment requirements which include; Annual Transmission Revenue requirements, Forecasted Transmission Revenue and Annual True-ups e.g. accounting for over/under recovery. PTF charge = (all PTO's revenue requirements) / (sum of all PTO's monthly peaks) Note: this is then divided by 8760 to reflect an hourly charge to participants. A discount to the PTF can be offered by PTO's. This offer must be made public and available to all participants connected to the line in question (subject to constraints). Pool Regional Network Service = This covers costs not recouped through the PTF i.e. the ISO costs. RNS charge = (RNS rate) x (monthly network load of participant) RNS rate = $/ kWh It is a monthly charge. Note: a participant's monthly network load is recorded at the hour when the aggregate load is at its peak in the network. Currently, individual local network RNS rates are converging towards a pool RNS rate.

ISO New England TUoS Tariff	
Energy Vs Capacity	The RNS is energy based. Participants are charged on their MWh when the network is at its MWh monthly peak. The PTF is the same charge per hour to every participant but the rate in influenced by all participants' energy usage e.g. The sum of all PTO's monthly peaks.
Demand / Generation split	This information is not available.
Costing Approach	This is not applicable because a postage stamp methodology is adapted.
Dispatch / Scenarios (treatment of wind and interconnection)	This is not relevant to the methodology as a postage stamp approach is used.
Volatility Mitigation Technique	There is no volatility mitigation technique's used.
Network Optimisation	It is not applicable because there is no costing of the network due to the use of a postage stamp methodology.
Scaling e.g. delta multiplier	It is not applicable because the tariff is a postage stamp method. The PTF is adjusted in the following year (termed Annual true-ups) to adjust the tariff to reflect under/over recovery.
Zonal Vs Nodal	Every participant is charged a zonal PTF rate. Note that local RNS charges (zonal RNS charges) are being converged towards a pool rate.

ISO New England TUoS Tariff	
Asset included e.g. system support, for instance capacitor	This is not relevant to the methodology as a postage stamp approach is used.
Period of Interest	Tariff is calculated on a yearly basis.
Implementation Date	Q4 2010

Table 19: New England Tariffs

ISO New England Losses	
Location Vs Uniform	Locational.
Purchase Vs Loss Adjusted	Loss adjusted. The loss factor in conjunction with bid price determines whether the bid is selected for dispatch. The Locational Marginal Price reflects the cost of losses.
Demand / Generation split	The loss factor affects generator bid price.
Fixed / Non-fixed	This information is not available.
Ex-ante/ Ex-post	Ex-ante. The loss factor is forecast for every trading period e.g. 5 minute trading intervals and for the day ahead trading.
Single / Multi-part	The loss factor reflects the change in losses for every change in the MW output. It is an incremental loss factor. The loss factor is linearly modelled.
Dispatch (treatment of wind and interconnection)	This information is not available.
Period of Application	Loss factors are calculated dynamically for the spot / 'Real Time' market e.g. every 5 min trading period. They are calculated daily for the 'Day Ahead' market.

Marginal Vs Average	Marginal loss factor.
Incumbent Vs New entrant	There is no difference specified.
Implementation Date	Not Applicable

Table 20: ISO New England Losses

4. New Zealand energy industry

Transpower is a state-owned independent transmission company. The transmission network in New Zealand is an isolated system. The islands are connected by a HVDC line. There is a pool energy market in New Zealand operated by M-Co. The bid price is based on a nodal pricing philosophy e.g. location marginal price. The price includes energy prices, constraints and losses.

The total generation capacity of New Zealand is approximately 3,500 MW. There is currently 321 MW of wind turbines connected to the network and produces 2.5% of the energy generated in New Zealand. Wind projects with a capacity of approximately 192 MW are expected to be connected shortly. This would bring wind farms to account for 14% of installed generation capacity.

Transpower have recently invested NZ $2 billion (approximately €800 million) and will be investing NZ $3.8 billion (approximately €1.5 billion) over the next five years. The tariff ('interconnection allocation') will reflect this increase in the capital expenditure. The development may also change the loss rate for participants.

Transpower and the Electricity Commission are undertaking a review of the transmission pricing allocation methodology. A decision paper is due at end of 2010. A new regime will be in effect from 2012. The determination of the tariff revenue requirement is not under review.

TUoS

There is a shallow connection policy in place. However, participants pay for shallow connection over a number of years. There are two categories in the TUoS tariff. Firstly, there is the 'Connection Allocation'. The participant (either generator or demand) pays a cost for their ownership share of assets at a connection location. The cost of a location includes asset return, maintenance of substations and lines, switching and injection overhead. If the percentage share cannot be determined by ownership then the percentage share is based on the MW demand or injection by each participant at a connection location.

The amount of the tariff revenue requirement to be accounted for through the 'Interconnection Allocation' category is the residual of the tariff revenue requirement after the value of the 'connection allocation' has been calculated. Only demand customers pay this particular category. It is allocated based on a demand customers peak MWh in a number of periods. Therefore, it is a form of the postage stamp methodology. There are no volatility mitigation technique's used. The primary driver for the tariff to differ from year to year is based on the value of the regulatory asset base. This is value using an optimised deprival value technique.

Cost of Losses

Detailed information on how the losses are treated in the New Zealand energy industry was difficult to locate. Loss factors are calculated ex-ante at each node. They are marginal loss factors. The cost of losses is incorporated in the Location Marginal Price.

New Zealand TUoS Tariff	
Connection Policy	Deep connection policy. Shallow connection costs are recovered over a number of years (see Connection Allocation).
Locational (incl. load flow) Vs Postage stamp	A form of postage stamping is used for 'Interconnection Allocation'. This is the residual of the tariff left after calculating the 'Connection Allocation'. The 'Interconnection Allocation' covers the costs not directly associated with a connection point e.g. the core network assets. 'Interconnection allocation' is distributed based on demand customers peak utilization i.e. peak MWh in a number of periods. Connection assets include both direct connection and radial network assets. The cost of a location (asset return, maintenance of substations and lines, switching and injection overhead) are first determined and then allocated to participants. The 'connection allocation' is based on a participant's percentage share of the usage of assets at a connection location. The percentage is based upon the participant's maximum demand or maximum injection compared to the total demand or injection at a connection location. There also a charge for the HVDC line. This is levied on generators in the South Island. Allocation is based on historical anytime maximum injection level. Additionally, there is an 'economic value adjustment charge' which accounts for adjustments of over/under recovery from the above charges. There may be exceptions to this process when a 'new investment contract' is undertaken to pay for the capital cost of connection assets.
Energy Vs capacity	The 'Interconnection Allocation' is based on energy. The 'connection allocation' is based on maximum demand or maximum injection.

New Zealand TUoS Tariff	
Demand / generation split	This information is not available. However, only demand customers pay the ‘Interconnection Allocation’ and both generators and demand customers pay for the ‘connection allocation’.
Costing approach	This is not applicable because a postage stamp methodology is adapted.
Dispatch / Scenarios (treatment of wind and interconnection)	The peak utilisation rate used in the ‘interconnection allocation’ is different in Upper North/South islands and lower North/South islands. The upper parts are based on the half hour of the 12 highest regional demands in a year. The lower parts are based on the half hour of the 100 highest regional demands in a year.
Volatility Mitigation Technique	There are no Volatility Mitigation Technique’s.
Network Optimisation	Not Applicable
Scaling	There is an ‘economic value adjustment charge’ which accounts for adjustments of over/under recovery.
Zonal Vs Nodal	Not Applicable
Asset included e.g. system support, for instance capacitor	Not Applicable
Period of interest	Tariff is done on yearly basis.

New Zealand TUoS Tariff	
Implementation Date	Q4 2010

Table 21: New Zealand Tariffs

Table 22: New Zealand losses

New Zealand Losses	
Location Vs Uniform	Losses are located at each node.
Purchase Vs Loss Adjusted	Loss adjusted. The Locational Marginal Price reflects the cost of losses.
Demand / Generation split	The loss factors affect the Locational Marginal Price.
Fixed / Non-fixed	There are fixed losses at transformers.
Ex-ante/ Ex-post	Ex-ante. The losses are forecast.
Single / Multi-part	Currently loss factor are linearly modelled.
Dispatch (treatment of wind and interconnection)	Assume that the loss mechanism creates efficient dispatch.
Period of Application	This information is not available.

New Zealand Losses	
Marginal Vs Average	Marginal loss rate used for pricing loss and the average loss rate is used to measure the quantity of losses.
Incumbent Vs New entrant	No difference in cost of losses between participants.
Implementation Date	Not Applicable

5. Norwegian energy industry

Statnett is the state-owned independent transmission company. Therefore, it acts as both a system operator and transmission asset owner. Its responsibilities for each of these roles are similar to those found in Ireland. Norway has a high level of interconnect with its neighbouring countries and an energy market, called Nord pool (participants include Sweden, Denmark East, Finland, Iceland) was developed to help facilitate this interconnection between members.

Nord pool is always cleared at a system price (unconstrained price) in first hand. If there are constraints, zonal prices will occur after the second market clearing (constrained price). Norway has 3 zones for this current period. The number of zones can change from 1 to 6 depending on judgment by Statnett on the requirements of security of supply. Participants pay for losses through their respective tariffs.

Norway's installed capacity is approximately 30,000 MW (Nordel Annual statistics 2007) and its consumption over the last year has peaked at approximately 22,000 MW. The Norwegian generation portfolio is dominated by hydroelectric power produced in the North of the country (approximately 29,000 MW). The central demand load area is in the south of the country. Therefore, the prevailing load flow is from North to South. While the amount of hydroelectric power is dependent on the level of precipitation it has a stable and non-volatile load frequency and can be forecast consistently. The installed capacity of wind is approximately 380 MW.

Statnett plans on investing NOK 18 billion (approximately €2 billion) on the grid over the next 10 years. There is currently a shallow connection policy (discussions are underway on the best method of incorporating deep connection charges). Thus, the tariff will increase in line with the grid investment.

Norwegian Tariff Regime

The tariff regime incorporates both the cost of losses and TUoS. The pricing methodology is fixed for a there year period. A new pricing methodology will be implemented for the 2010-2012 period. The tariff revenue requirement itself is calculated on an annual basis. The following information is based upon the methodology for the 2007-2009 period.

Cost of Losses

Statnett (TSO) purchases the losses in the Nordic market pool and charge market participants for the cost of losses (it is collected through an energy component charge). A marginal loss rate factor is forecast ex-ante at each node on a weekly basis. The participant is charged for the marginal loss rate for the energy produced or consumed at a node (hour by hour), based upon the system price. This creates a transmission locational signal regarding the cost of losses. The marginal loss rate factor is currently capped at +/- 10%. This will increase to +/- 15% from 2010. This creates an upper and lower limit in what the loss factor can be. This creates some form of stability (albeit a broad range) in the mechanism. Additionally, the electricity system itself should be stable and predictable due to the dominant energy flow from North to South.

TUoS

A form of postage stamping is used to collect the fixed cost component of the tariff. Each participant category (Producer, Consumer and Power Intensive Industry) is allocated a different form of postage stamping. Bearing in mind that the fixed cost component is calculated first, the variable cost (e.g. energy component) collects approximately 25% of the tariff and the fixed cost component collects approximately 75%.

A set rate is devised in each category. Therefore, this does not provide a transmission locational signal (note the energy component provides a transmission locational signal). Furthermore, the large determent in the overall tariff charge is the revenue requirement (driven by Statnett's investment and operational needs, as well as the cost of losses). The variation of the overall tariff revenue requirement determines how stable the tariff is from year to year.

The application of reduced tariff arrangement provides a transmission locational signal to generators. A generator connecting to the grid in an area which is considered favourable to the grid by Statnett can avail of a reduced tariff. A set reduction in the tariff is fixed for a 15 year period. The applicable grid areas and level of the tariff reduction is set on a yearly basis by Statnett.

Norwegian TUoS Tariff (includes the cost of losses)	
Connection Policy	Shallow. A Deep connection policy is currently being considered.
Locational (incl. load flow) Vs Postage stamp	Energy component is a load flow. It is a variable cost and covers the cost of marginal losses. Energy component (NOK) = system price (NOK/MWh) • marginal loss rate (%) • energy consumption/ production (MWh) System price = unconstrained price Marginal Loss Rate = calculated at each node & done on a weekly basis. The marginal loss rate is administratively limited to +/- 10%. This will increase to +/- 15% from 2010. Energy consumption/production = based on current usage (hour by hour); it is the net consumption/production at an exchange point/node. The residual left to pay in the tariff is allocated on fixed costs basis. This is component is calculated ex-ante. It is charged using a postage stamp methodology. There are three different categories. Production = allocated on the average annual production for the 1998-2007 period Consumption = Based on customer firm's 5 year average total consumption in MWh/ peak load hour.

Norwegian TUoS Tariff (includes the cost of losses)	
	Power intensive industry = (settlement basis in MW) x (tariff rate of fixed component for consumption in NOK/MW) Reduced tariff available to new generation when its introduction is favourable to the grid. A set reduction in the tariff is fixed for a 15 year period. The applicable grid areas and level of tariff reduction is set on a yearly basis by Statnett. Therefore, this arrangement provides a transmission locational signal to generators.
Energy Vs Capacity	The energy component is based on energy. The postage stamp (fixed cost) is based on either energy or capacity depending on the category.
Demand / Generation split	75% of tariff paid by Demand 25% paid by Generation Note: both generation and demand pay the energy component. Also, these figures can vary from year to year. Note. The percentage is not decided ex ante. The fixed component is determined ex-ante while the energy component will be charged as incurred. Therefore, the percentage allocation between Demand and Generation differ from year to year.
Costing approach	Not Applicable
Dispatch / Scenarios (treatment of wind and interconnection)	Energy component done hour by hour. Fixed cost is based on 5 year average peak load.
Volatility Mitigation Technique	From 2010, in the energy component the marginal loss rate is administratively limited to +/- 15%. It is currently +/- 10%.

Norwegian TUoS Tariff (includes the cost of losses)	
Network Optimisation	Costs or its allocation are not done on a network optimisation basis.
Scaling e.g. Delta multiplier	Not Applicable
Zonal Vs Nodal	The marginal loss rate is calculated at each exchange point/node.
Asset Included (system support e.g. capacitors)	Not Applicable. The tariff methodology does not require assets costs.
Period of Interest	Price strategy is set for 3 years. Tariff revenue requirement set on a yearly basis.
Implementation Date	Energy Component Not Applicable Fixed Component Q4 2010

Table 23: Norwegian Tariffs

Table 24: Norwegian Losses

Norwegian Losses	
Location Vs Uniform	Losses are located at each exchange point/node.
Purchase Vs Loss Adjusted	TSO purchase the losses. The cost of this is then reflected in the tariff charge (through energy components). A loss factor is utilised to allocate the cost of the losses to participants in the tariff (marginal loss rate).
Demand / Generation split	Net consumption / production determines the allocation of losses at each exchange point/node
Fixed / Non-fixed	No information available on whether part of the losses is fixed.
Ex-ante/ Ex-post	Marginal loss rates are calculated ex-ante on a weekly forecast basis. The amount of energy consumption/ production at a node is measured ex-post.
Single / Multi-part	Separate marginal loss rates are calculated for day and night/weekend on a weekly basis.

Norwegian Losses	
Dispatch (treatment of wind and interconnection)	Efficient in respect of losses caused by generation and demand.
Period of Application	Weekly loss rate.
Marginal Vs Average	Based on Marginal loss rate.
Incumbent Vs New entrant	No difference in cost of losses between participants. (Please note that a reduced tariff is available to new generation in certain favourable areas for a 15 year period).
Implementation Date	Not Applicable

6. National Energy Market energy industry

The greater part of the Australian energy industry is structured within the National Energy Market (NEM). The focus of this report will be on this market. There are 6 regions in the National Energy Market (NEM) – Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania. Market participants buy and sell electricity in the NEM. National Electricity Market Management Company Limited (NEMMCO) is currently both the System Operator and Market Operator for NEM. From July 1 2009 NEMMCO will be merging with a number of other utility companies to form the Australian Energy Market Operator (AEMO). The AEMO is responsible for both electricity and gas transmission services. The Australian Energy Regulator oversees every part of Australia, including the NEM.

In Australia each region has its own Transmission Network Service Provider. Transmission assets in NEM are 60% owned by the state and 40% by private entities. The NEM regions are interconnected. There are both regulated and unregulated interconnectors.

The generation portfolio in the NEM is dominated by conventional power. 59% of power is generated from black coal, 25% brown coal, 8.5% natural gas, 7.2% hydro-electric power and 0.3% oil and other (NEMMCO June 2008, an introduction to Australia's national electricity network). The typical demand for electricity in the NEM is approximately 25,000 MW. There is plenty of energy supply to facilitate this level of demand. The system only comes under pressure during for a few hours during a small number of days of extreme heat. Furthermore, the difficulty does not occur simultaneously in every region and the energy supply can be shared across regions. Additionally, Victoria and South Australia have peak generators to assist in managing short-demand peaks during the summer months.

National Energy Market Tariff Regime

The methodology for TUoS and Losses is very similar in every region within the NEM. There are slight differences between the regions but on the whole the following discussion and templates is representative of how each region handles TUoS and Losses.

TUoS

There are three TUoS categories in the tariff. The TUoS is charged to demand customers. Generators do not pay for TUoS. In addition, there is a separate connection charge. This latter charge applies to both generators and demand customers.

The first TUoS category under discussion is the Customer TUoS Usage Charge. This charge varies by location. However, in total 50% of this tariff will be collected through energy charges and the other 50% will be collected through a capacity charge. The usage energy charge at every node is allocated on a kWh basis. The usage capacity charge is allocated on a kW basis per month. It is based on the MW peak demand during the past financial year.

The second TUoS category is the Customer TUoS General Charge. Every customer is charged the same rate i.e. postage stamp. A customer can choose to be charged under the energy charge or capacity charge. These are similar to the Usage Charge energy and capacity charges. If the capacity charge is chosen a customer will be charged the lower of the capacity charge or the energy charge. They will however be penalised if the amount of demand agreed in the contract is exceeded.

The third TUoS category is the Common Service Charge which is determined similarly to the General Charge. Customers are charged either an energy charge or a capacity charge. Again, there are penalties if the amount of demand agreed in the contract is exceeded.

In Queensland (it is unclear if it is applied to the other regions of the NEM) there is price cap on TUoS Usage Charge. The annual change of the Usage Charge at each node is capped at +/- 2% compared to the average change across all nodes.

Cost of Losses

The NEM uses marginal loss factors. Loss factor are given to each node. Therefore, they provide a transmission locational signal. These loss factors in conjunction with bid price determine whether the bid is selected for dispatch. The TSOs do not buy the losses in the energy market. There are two loss factors calculated. There is an intra-regional loss factor used for trades within a region. For trade across regions the intra-regional loss factor is used in conjunction with an inter-regional loss factor. Please refer to the template for more detail on the methodology behind the calculating the loss factors. The intra-regional loss factors are calculated ex-ante and are set for a period of one year. The inter-regional loss factors are more dynamic. They reflect the losses between regions for each trading period.

NEM TUoS Tariff	
Connection Policy	Shallow connection policy. Participants pay this over a number of years.
Location (incl. loss flow) Vs Postage stamp	There are a number of different TUoS tariff categories. TUoS is charged to demand customers. **Customer TUoS Usage Charge**. A customer pays an energy charge and a capacity charge. 50% of this particular charge is allocated to the energy charge and the other 50% is allocated to the capacity charge. This charge varies with location. The usage energy charge is load flow based. • Usage energy charge = the cost is allocated on a kWh basis • Usage capacity charge = the cost is allocated on a kW basis per month. This is based on a measurement of peak demand. **Customer TUoS General Charge -** customer chooses either an energy charge or a capacity charge. If the capacity charge is chosen a customer will be charged the lower of the capacity charge or the energy charge. They will however be penalised if the amount of demand agreed in the contract is exceeded. This is charge is postage stamp. Every demand customer pays the same rate of fee. • General energy charge = the cost is allocated on a kWh basis • General capacity charge = the cost is allocated on a kW basis per month **Common Service Charge.** A customer chooses either an energy charge or a capacity charge. If the capacity charge is chosen a customer will be charged the lower of the capacity charge or the energy charge. They will however be penalised if the amount of demand agreed in the contract is exceeded. This is charge is postage stamp. Every demand customer pays the same rate of fee.

NEM TUoS Tariff	
	• Common Service energy charge = the cost is allocated on a kWh basis • Common Service capacity charge = the cost is allocated on a kW basis per month **Connection Charges -** Demand customers pay an exiting charge. Generators pay an entry fee. There is a fixed charge per month.
Energy Vs Capacity	Customer TUoS Usage Charge is 50% energy and 50% capacity. Customer TUoS General Charge can be either energy or capacity. Common Service Charge can also be either energy or capacity. The connection charge is neither.
Demand / Generation split	Demand customers pay for the TUoS tariff. Both demand and generators pay for connection charges.
Costing approach	Network costing is required at a connection point to determine the Connection Charges e.g. shallow cost to connected participants.
Dispatch / Scenarios (treatment of wind and interconnection)	This is not relevant to the methodology as a postage stamp approach is used (for the majority of the methodology).
Volatility Mitigation Technique	In Queensland (TSO = Powerlink), the Customer TUoS Usage Charges price for each connection point is capped at +/- 2% relative to the average price change for all customers. It is unclear if this applied to other regions in the NEM.
Network Optimisation	There is no network optimization.

NEM TUoS Tariff	
Scaling e.g. Delta multiplier	It is not applicable because the tariff is a postage stamp method. The kWh and KW in the calculations are historically based.
Zonal Vs Nodal	The Customer TUoS Usage Charge is determined at each node location. It varies from node to node. This does not apply in the other tariff categories because postage stamping methodology is used.
Asset Included e.g. system support, for instance Capacitor	Not Applicable
Period of Interest	The tariff is set for each year.
Implementation Date	Q4 2010.

Table 25: NEM Tariffs

NEM Losses	
Location Vs Uniform	There is Intra-Regional loss factor (within the region) and a Inter-Regional loss factor (interconnection between regions). The intra-regional loss factor is calculated by getting the volume weighted average of the marginal loss factors that occur between each connection node and the regional reference node in a year. This provides a locational loss factor for each connection node. This is set for 12 month period. The inter-regional loss factor is calculated by inputting a marginal loss factor for a regional reference node into an optimised algorithm to determine dispatch. It is dynamically calculated. It is a uniform loss factor. Each generator within a region which sells electricity into another region is faced with the same loss factor cost for the use of the interconnector. Inter-regional bids reflect both the intra-regional loss factor at a node and the inter-regional loss factor between regional reference nodes. The following NEMMCO papers outline the methodology which determines the loss factors. http://www.nemmco.com.au/psplanning/172-0032.pdf http://www.nemmco.com.au/psplanning/172-0064.pdf
Purchased by TSO Vs Loss Adjusted	Loss factors are used. These loss factors in conjunction with bid price determine whether the bid is selected for dispatch.

NEM Losses	
Demand / generation split	This information is not available.
Fixed / Non-fixed	This information is not available.
Ex-ante/ Ex-post	Ex-ante. The intra loss factor is forecast for the forthcoming year. The inter loss factor is more dynamic but is still forecast.
Single / Multi-part	Loss factors do not vary for the level of MW output by a generator.
Dispatch (treatment of wind and interconnection)	The use of more than one set of loss factors for each node will lead to more efficiency with regards to intra-regional dispatch. The use of more dynamic loss factors for inter-regional trade should lead to more efficient interconnection dispatch.
Period of Application	Intra-regional loss factors fixed for the year. Inter-regional loss factor for regional reference node is forecast on a more dynamic method. The timelines of this are not available.
Marginal Vs Average	Intra-Regional loss factor is the volume weighted average of the marginal loss factors that occur between each connection node and the regional reference node in a year. Inter-Regional loss factor is determined by the marginal loss at the regional reference node.

NEM Losses	
Incumbent Vs New entrant	No difference in cost of losses between participants.
Implementation Date	Q4 2010.

Table 26: NEM losses

7. PJM energy industry

PJM interconnection is a Regional Transmission Operator (RTO). It does not own any transmission assets. It operates both the transmission grid and also the wholesale energy market in the region. The PJM interconnection footprint covers 13 states (North East of America) and the District of Columbia. PJM covers 168,500 square miles. The area has a peak demand of 144,644 MW. The generation portfolio in PJM footprint includes approximately – 56.4% coal, 34.2% nuclear power, 5.9% natural gas, 1.2% oil, 1.7% hydroelectric power, 0.6% solid waste and 0.1% wind (PJM 2005 figures). There are 74,000 points/nodes on the grid. Constraints in the transmission grid are extensive. They cost $2.1 billion in 2005 and $1.6 billion in 2006[6].

PJM Interconnection Tariff Regime

The same tariff regime is applied to every state within PJM's footprint. The cost of losses is treated separately to the rest of the tariff.

TUoS

TUoS is charged directly to demand customers. There are two categories within TUoS. Firstly, there is the Network Integration Transmission Service Charge. This charge varies from zone to zone within the PJM region. This provides a transmission locational signal. However, within a zone the allocation is determined by a postage stamp method. Every participant in a zone pays the same charge rate. The rate is applied to their daily peak load contribution (including losses). It is an energy based charge. Secondly, the Point-to-Point Transmission Service charge utilises postage stamping and is based on a demand customer's capacity level. Using these categories means that the tariff is somewhat predictable. However, the absolute

TUoS revenue requirement may change and therefore adds unpredictability to the tariff.

Cost of losses

The cost of losses is allocated on a locational basis. Each node on the grid is allocated a loss factor, called a penalty factor. This penalty factor reflects the change in losses for every change in the level of MW output. It is a marginal loss factor. It is measured dynamically. A penalty factor is calculated for every trading period. The 'Real-Time' market has five minute periods while the 'Day Ahead' market has daily periods.

Note generators receive a Locational Marginal Price (LMP). This consists of the System Marginal Price (SMP), the cost of constraints and the cost of losses. Generators are compensated for the cost of losses in the LMP through adjusting the bid price that they make. Therefore, the SMP will reflect the cost of losses. Financial Transmission Rights are used to hedge against the risk of constraint costs varying.

PJM TUoS Tariff	
Connection Policy	Deep connection.
Locational (incl. load flow) Vs Postage stamp	**Network Integration Transmission Service Charges** are location load flow charges e.g. different zone rates. However, within a zone it is a form of postage stamp. The same zone rate applies to demand customers. The rate is applied to their daily peak load contribution (which includes losses). (Zonal network rate \$/MW) • (daily peak load) **Point-to-Point Transmission Service** is a form of postage stamping. It is based on a customers capacity - \$/kW
Energy Vs Capacity	The Network Integration Transmission Service Charges is an energy charge. The Point-to-Point Transmission Service is a capacity charge.
Demand / Generation split	Both service charges are charged to demand customers.
Costing Approach	Network costing is not needed in the methodology as a form of postage stamp approach is used.
Dispatch / Scenarios (treatment of wind and interconnection)	This is not relevant to the methodology as a form of postage stamp approach is used.
Volatility Mitigation Technique	There are no Volatility Mitigation Techniques.
Network Optimisation	It is not applicable because there is no costing of the network due to the use of a postage stamp methodology.

PJM TUoS Tariff	
Scaling e.g. Delta multiplier	It is not applicable because the tariff is a postage stamp method. It is unclear if tariff is adjusted ex-post to account for any over/under recovery in the tariff requirement.
Zonal Vs Nodal	The Network Integration Transmission Service Charge utilises different rates of postage stamp in different zones.
Asset Included e.g. system support, for instance capacitor	This information is not relevant to the methodology as a postage stamp approach is used.
Period of Interest	The tariffs are set annually.
Implementation Date	Q4 2010

Table 27: PJM Tariffs

Table 28: PJM Losses

PJM Losses	
Location Vs Uniform	Locational.
Purchase Vs Loss Adjusted	Loss adjusted. The loss factor (or penalty factor) in conjunction with bid price determines whether the bid is selected for dispatch. The Locational Marginal Price reflects the cost of losses. Cost of losses = System Price x [(1/Penalty Factor) – 1] System Price = unconstrained price Penalty factor = 1/ (1- Δ in losses/ Δ Unit's MW output) Note: that system price is determined by a price that reflects the penalty factor.
Demand / Generation split	The loss penalty factors affect the Locational Marginal Price.
Fixed / Non-fixed	This information is not available.
Ex-ante/ Ex-post	Ex-ante. The penalty loss factor is forecast for every trading period e.g. 5 minute trading intervals and for the day ahead trading.

PJM Losses	
Single / Multi-part	The penalty loss factor reflects the change in losses for every change in the MW output. It is an incremental loss factor. The loss factor is linearly modelled.
Dispatch (treatment of wind and interconnection)	This information is not available.
Period of Application	Dynamically for the spot / 'Real Time' market e.g. every 5 min trading period. Daily for the 'Day Ahead' market.
Marginal Vs Average	Marginal loss factor.
Incumbent Vs New entrant	There is no difference specified.
Implementation Date	Not Applicable

8. Swedish energy industry

Svenska Kraftnät is the Swedish Transmission System Operator and part of the state administration. It is the system operator for both electricity and gas. It is responsible for providing a secure, efficient and environmentally compliant transmission of electricity to the country. Sweden has a highly interconnected network with its neighbouring countries.

Sweden has 34,068 MW of installed capacity. The generation portfolio consists of 16,209 MW of hydro-electric power, 9,074 MW of Nuclear power, 8,005 MW of thermal power and 780 MW of wind[7]. A significant expansion of wind is expected by Svenska Kraftnät[8]. The predominant flow of power on the national grid is from north to south. The network has largely been built to be able to transfer hydro-electric power from the North down to the load areas of Central and Southern Sweden. Sweden has a deep connection policy on the National Grid.

Swedish Tariff Regime

The tariff regime in Sweden includes both the cost of losses and TUoS. An investment charge may arise if a connecting participants cost of connection is not covered by normal charges. The tariff must make it possible to pass on the full transmission cost. This is ensured by a tariff at the point of connection for consumers. The producers’ tariff may, according to the law governing transmission and distribution tariffs, be configured either at the point of connection, or according to the physical route (passing along of costs related to equipment actually used to transfer generation to the nearest place of consumption and not the producer’s actual customer).

[7] Nordel Annual Statistics 2007
[8] Svenska Kraftnät Annual Report 2007

Svenska Kraftnät uses tariffs per point of connection for the National Grid. Grid service customers are in principle owners of regional grids and large power stations. The grid charge consists of three parts:

- Capacity charge
- Energy charge
- Investment charge

The predominant flow of power on the National Grid is from north to south. The grid has largely been built to be able to transfer hydropower from Northern Sweden down to the consumption areas of Central and Southern Sweden. To reflect this in the tariff the charges for entries are high in Northern Sweden, while the charges for exits are low. The opposite applies to Southern Sweden.

TUoS

The Swedish equivalent of TUoS is the capacity charge. The capacity charges are based on annual subscriptions at each point of connection. The annual entry fee is SEK 31/kW in the north. It decreases linearly with the latitude to SEK 6/kW in the south. For the exit fee the reversed principle applies. It is SEK 14/kW in the north and year and increases linearly with the latitude to SEK 58/kW in the south.

Cost of Losses

Svenska Kraftnät (TSO) purchases the losses. The cost of this is recovered through the energy charge. This creates a transmission locational signal regarding the cost of losses. The energy part of the grid charge is based on measured input or output energy at each point of connection. It reflects the grid’s marginal transmission losses and is calculated as the product of the marginal loss coefficient, loss-energy price and energy input/output. The loss coefficients vary geographically between ±10 percent. Entries in the south and exits in the north reduce the grid’s transmission losses. The energy charge can be either positive or negative depending on a participant's impact on transmission losses. The loss-energy price of energy is decided in advance, one calendar year at a time. The price is based on the bulk-purchasing rate that Svenska Kraftnät pays its energy suppliers to cover grid losses. For 2007 the average energy fee was SEK 0.25/kWh, and divided into four periods according to the table.

Time of day	**Energy fee**	**Time of year**
Daytime	SEK 0.300/kWh	November – March
Night and weekend	SEK 0.270/kWh	November – March
Daytime	SEK 0.250/kWh	April - October
Night and weekend	SEK 0.210/kWh	April – October

Investment charge

Occasionally, the connection of a customer's plant to the National Grid can entail investments not covered via normal charges. In such cases, Svenska Kraftnät can impose an investment charge on the customer.

Swedish TUoS Tariff (includes the cost of losses)	
Connection Policy	Deep.
Locational (incl. load flow) Vs Postage stamp	The energy charge segment of tariff is based on a load flow methodology. It covers approximately 50% of the tariff. Energy charge = (marginal loss co-efficient) • (loss energy price) • (energy input/output) Marginal loss co-efficient = It varies geographically between +/- 10%. It is calculated using load flow models representing four periods of the year. There are different coefficients for the time of the year and also the time of the day. Loss energy price = The loss-energy price of energy is decided in advance, one calendar year at a time. The price is based on the bulk-purchasing rate that Svenska Kraftnät pays its energy suppliers to cover grid losses. There are different rates for the time of the year and also the time of the day. Input/output = Energy injected into the grid or withdrawn. Note – the energy charge can be either positive or negative depending on a participant's impact on transmission losses. Entries in the south and exits in the north reduce the grid's transmission losses; hence they receive a negative energy charge. The other half of the tariff is determined by a Capacity charge. The capacity charges are based on annual subscriptions at each point of connection. The annual entry fee is SEK 31/kW in the north. It decreases linearly with the latitude to SEK 6/kW in the south. For the exit fee the reversed principle applies. It is SEK 14/kW in the north and year and increases laniary with the latitude to SEK 58/kW in the south.
Energy Vs Capacity	50% of the tariff is covered on an energy basis (energy charge). The other 50% is covered through a capacity basis.

Swedish TUoS Tariff (includes the cost of losses)	
Demand / Generation split	Based on total tariff. 75% = Demand 25%= Generation
Costing approach	The Weighted Average Cost of Capital and RAB combination methodology is not used to determine the tariff revenue requirement. There is no Network costing in the tariff methodology.
Dispatch / Scenarios (treatment of wind and interconnection)	There are different loss energy prices depending on the time of the year (peak load = November to March, low load = April to October), the time of the day and also the stage of the week (week days and the weekend).
Volatility Mitigation Technique	The positive/negative bound around the loss co-efficient is due to administrative restrictions.
Network Optimisation	Costs or its allocation is not done on a network optimisation basis.
Scaling e.g. Delta multiplier	No information available.
Zonal Vs Nodal	Energy charge is done on a nodal basis. Capacity charges are also nodal (determined by geographical location). There are two charges per point of connection, one for entry and one for exit.
Asset Included e.g. system support, for instance Capacitor	This information is not available.
Period of Interest	The tariff is determined annually.
Implementation Date	Q4 2010

Table 29: Swedish Tariffs

Table 30: Swedish Losses

Swedish Losses	
Location Vs Uniform	Losses are located at each node.
Purchase Vs Loss Adjusted	TSO purchases losses. The cost of this is then reflected in the tariff charge (through the energy charge). A loss factor is utilised to allocate the cost of the losses to participants in the tariff (loss co-efficient).
Demand / Generation split	Both demand and generators pay energy charge based on their outtake or input respectively. The split between demand and generator in the energy charge is unknown. However, the overall tariff is divided by 75% demand and 25% generation.
Fixed / Non-fixed	Losses charges are based on measured flows ex-post.
Ex-ante/ Ex-post	The marginal loss co-efficient is calculated ex-ante for two periods in the year (November-March and April-October) and also for two periods of the day (daytime and night and weekend). The amount of energy input/output at a node is measured ex-post.
Single / Multi-part	Different loss co-efficient are calculated for the time of year and also for weekdays/weekends. Night and weekend loss energy prices are set on an annual basis.

Swedish Losses	
Dispatch (treatment of wind and interconnection)	Efficient in respect of losses caused by generation and demand.
Period of Application	Tariff is set on a yearly basis.
Marginal Vs Average	Marginal loss rate
Incumbent Vs New entrant	No difference in cost of losses between participants.
Implementation Date	NOT APPLICABLE

9. England, Scotland & Wales Energy Market

National Grid owns and maintains the high-voltage electricity transmission system in England and Wales, together with operating the system across Great Britain.

Transmission Losses and Transmission use of System Charges are recovered through separate mechanisms in GB, these are outlined below.

Tariff regime

National Grid's Transmission Network Use of System (TNUoS) tariff comprises of two separate elements. Firstly, a locationally varying element derived from the DC Load Flow (DCLF) Investment Cost related Pricing (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 to ensure the correct transmission revenue requirement is recovered. The combination of both these elements forms the TNUoS tariff. The methodology is used to derive demand tariffs as well as generator tariffs. A more detailed explanation of National Grid's charging methodology can be found in the document "*Statement of the Use of System Charging Methodology*" available on National Grid's website[9]

Basis of the tariff model

National Grid's tariff methodology combines locational zonal tariffs with a postage stamp tariff. The underlying rationale for including a locational Use of system charge is that the differential in charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the transmission 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. The inclusion of a postage stamp, or residual tariff, is to ensure that the full amount

[9] http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/

of the annual required transmission revenue is recovered from transmission system users via the tariffs.

Like most Transmission System Operators National Grid are required to operate, plan and develop the transmission system to meet specified security standards; capital investment requirements are largely driven by the need to conform to these standards. It is this obligation, which provides the underlying rationale for using the ICRP approach to derive locational tariffs, 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. The DC Load Flow ICRP transport model calculates the increase (or decrease) in capacity that is needed for a MW increment in generation at each node. This value for each individual node is then multiplied by the annual capital and maintenance cost of a Km of transmission capacity required for 1MW to give the transport charge for generation at each node. 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 km of the transmission system for a 1 MW injection to the system.

Methodology for calculating the Locational transport tariff

The following steps are performed to derive the locational transport tariff for each zone:

- Using a set of inputs representative of peak conditions on the transmission system incremental/decremental marginal costs are calculated by placing 1MW of additional generation at each node, one by one, and reducing 1MW of demand from the reference node. Each time the marginal cost for the whole network is calculated and expressed in MW.Km.
- Nodes are zoned appropriately depending on geographical and electrical proximity.
- Zonal costs are multiplied by the Expansion constants to convert the marginal MW.km figures into a £/MW signal and by a Locational Security factor to reflect the difference in cost incurred on a secure network as opposed to an unsecured network.
- Finally, in order to obtain the correct revenue recovery split of 27/73 from generation and demand a final adjustment is calculated and a constant is added/subtracted to produce the final locational transport tariff for each zone.

Residual Tariff

The residual tariff is a postage stamp tariff, which is added to the generator and demand users locational tariff. It is unlikely the revenue forecast to be recovered from the locational tariff will equal the total transmission required revenue, therefore a residual tariff is calculated in order to recover the remainder of the revenue. The residual tariff normally recovers approximately 85% of the total revenue. As before, the residual tariff is apportioned so that the 27/73 split of revenue recovery between generators and demand is maintained.

The final tariff for each generation and demand zone is the sum of the locational transport tariff and the non-locational residual tariff.

Energy Tariff for Demand Customers

Once the Transmission Network Use of System £/kW Demand Tariff has been derived, the energy consumption tariff for non-half hourly metered energy is calculated based on historical data and National Grid's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned.

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 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 unit, multiplied by the relevant zonal p/kWh tariff.

Cost of Transmission Losses

The costs of losses are allocated to generators and demand users. At present, the calculation of losses is based on Transmission loss Multipliers (TLMs), essentially a form of pro-rata allocation. Transmission losses are calculated on a uniform basis across England, Scotland and Wales and recovered half hourly, based on the metered difference between generation onto the system and consumption from the transmission system in each half hour settlement period.

Currently 55% of transmission losses are allocated to suppliers and the remaining 45% are allocated to generators in an attempt to give an equal share of the burden of losses. The rational for this split is that generators connected to the transmission system have their energy metered on the high voltage side of the generator transformer, i.e. the losses in the transformer are allocated to the generator whereas the energy being transferred from the transmission system to a distribution system is measured on the low voltage side of the Grid Supply Transformer i.e. the losses in the transformer are included in the overall Transmission Losses.

The generator TLM is calculated by dividing total system losses in each period by the total generation in that period and multiplying by the generators 45% share of losses. Similarly, the demand TLM is calculated by dividing total system losses in the period by the total demand in that period and multiplying by demand's 55% share of losses.

All TLM's are based on metered generation and consumption, they are only known after the event. Although this presents some additional risk, in practice TLM's tend not to vary much between settlement periods. This method takes no account of the geographic location of generators or demand users hence no incentive is provided for placing generation closer to load.

Table 31: NGUK Tariff Methodology

National Grid Tariff Methodology	
Deep versus Shallow charging	Shallow connection policy
Locational or Postage stamp tariffs	Combination Approximately 15% Locational based and 85% Postage stamp
Energy or Capacity based Charge	Generator: Capacity based charge Demand: Capacity based charge for metered energy Energy based for non-metered energy
Demand / Generation revenue split	27% revenue recovered from generator tariffs 73% revenue recovered from demand tariffs Both the locational tariff and the residual tariff are apportioned so that the 27/73 split of revenue recovery between generators and demand is maintained.
Costings Approach	Investment Cost Related Pricing **(ICRP)** The cost of capacity per MW.Km is derived, this represents the cost of building and maintaining the capacity to transport 1 MW of power 1 Km between points on the transmission system. This cost has two components, a capital cost and an operational cost. The basis of the capital cost is the current average cost at replacement value of the present system. The model constructs a least cost network that can transport peak power flows from exporting nodes to importing nodes. ➢ The physical location of substations is the same as on the current system ➢ Assets are precisely scaled to meet requirements ➢ No new wayleaves are assumed that might provide cheaper routing

National Grid Tariff Methodology	
	➢ Capacity of generation at each node is scaled to meet peak demand for the year so that total capacity equals total demand
Dispatch scenarios	Peak demand scenario. The charging method examines the peak condition because the security standards identifies requirements on the capacity of the system given the expected generations and demand at each node such that all reasonable demands for energy can be met. Historically, demand and generation levels at peak have driven up to 90% of investment.
Volatility Mitigation Techniques e.g. Capping	No explicit technique applied although aspects of the methodology seek to reduce volatility, such as zoning.
Network optimization	No
Scaling	Locational tariffs are scaled by a constant to ensure 27:73 revenue recovery split between generation and demand from the locational tariff. If the Final demand Tariff results in a negative number then this is set equal to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones.
Zonal v's nodal	For the locational component a Tariff is calculated for each node then these are zoned according to geographical and electrical proximity as well as tariff range The underlying principle of the nodal prices is that they should reflect the incremental or decremental cost associated with changes in demand and generation at that node. Given the Industry requirement for relatively stable cost messages and

National Grid Tariff Methodology	
	administrative simplicity, nodes are assigned to zones based on their geographical and electrical proximity and their tariff range. The effect of this is to dampen fluctuations that would otherwise be observed at a given node caused by changes in generation and demand patterns. There exists 21 generation zones and 14 demand zones, these zones are typically not reviewed more frequently than once every price control period to provide additional stability.
Assets included e.g. System support cap banks	Overhead line and cable as below. 132kV overhead line & cable 275kV overhead line & cable 400kV overhead line & cable
Period of Application	Calculated each year for a 12 month period
Implementation date	Q4 2010

Table 32: NGUK Losses Methodology

National Grid Losses Methodology	
Uniform or locational	Uniform allocation
Marginal V's average	Pro-rata
Ex-ante v's ex-post	Ex-post
Single v's multi part	Single transmission Loss multiplier
Dispatch Scenarios	Not based on a load flow, based on metered generation All types of generation are treated equally
Period of Application	By half hour settlement period
Fixed or Non-fixed	Fixed and non fixed losses are allocated uniformly
Incumbent V's new entrant	Uniform charge so all treated equally
Purchased V's adjustment fixed	Adjustment factor applied to recover cost of losses
% of losses applied to generators and suppliers	45 % recovered from generators 55% revenue recovered from demand
Likely implementation date	Q4 2010

10. Zonal TLAF Methodology

Over the past number of years proposals have been made on a number of occasions to make modifications to the current losses methodology applied in England, Scotland and Wales. One model in particular which appears to have been given extensive consideration for replacing the existing model involves the application of Zonal Transmission Losses factors. A number of variations of zonal losses schemes have been proposed however for the purposes of this document we shall consider the proposed methodology known as modification P198[10]. A more detailed description of this proposed modification can be found on Elexon's website.[11]

In the proposed scheme variable transmission losses would be allocated through zonal Transmission Loss Factors (TLF's) derived using a load flow model. All generation units within the same zone would receive the same loss factor and similarly all demand units within the same zone would receive the same loss factor. As in the current methodology, fixed losses would continue to be allocated uniformly.

Basis for proposing a Zonal Transmission Losses Scheme

The rationale for recommending that transmission losses are allocated based on location is made on the assumption that load flow models seem to be a generally accepted way of estimating marginal losses and also that losses do vary by location. Hence, an estimate of marginal losses derived from an appropriately specified load flow model is suggested to represent a more accurate reflection of physical reality than allocating losses uniformly without taking account of location.

Those in support of applying zonal locational transmission loss factors believe it would be more cost reflective than a uniform allocation of losses. The aim of this approach is that variable losses would be allocated locationally according to

[10] Modification proposal P198 is based on a previous modification proposal P82

[11] www.elexon.com/ChangeImplementation/modificationprocess/modificationdocumentation/default.aspx

the extent to which parties give rise to them. As a result, parties at a given location would receive either a positive or negative allocation of variable losses, depending on whether their actions have the impact of reducing or increasing the total level of losses on the system.

The intention of a zonal transmission losses scheme is to enable long-term transmission locational signals for losses to be introduced into the market. It is anticipated that this method of applying losses, to the extent that it influences the use of existing generation and the location of future investment, will reduce the total amount of electricity transmitted and therefore increase the efficient use of energy.

A further reason for suggesting the adoption of zonal loss factors is to remove any cross subsidies which exist. A concern of the using uniform losses is that it gives no signal to dispatch and locate generation closer to demand, the result of this is that generation in the South of England and demand customers in Scotland pay part of the cost of transporting electricity to locations miles away from the source of generation.

It is believed that a scheme based on the ex-ante calculation of losses would provide better information to users of the transmission system regarding implications of siting generation and new load in different parts of the country.

Calculating the Zonal Transmission Loss Adjustment Factors

In the load flow model, each node would be allocated to a zone on the transmission network, and the raw nodal marginal factors would then be averaged and scaled to calculate the zonal TLFs which would be used in the settlement calculations. The marginal loss factors derived from the load flow model are scaled before being used to derive the zonal TLFs, so as to ensure that the total volume of losses allocated through the TLF's is approximately the same as the total variable transmission losses. Fixed losses, which do not vary with power flows, would continue to be allocated on a non-zonal uniform basis.

A single transmission loss factor would be derived ex-ante for application to generation and demand within a zone for a relevant period. The scheme would retain the 45/55 split for allocation to generators and demand. The applicable zones would be the geographical area in which a grid supply point group lies.

In this scheme parties at a given location can receive a negative allocation of variable losses if their actions reduce the total level of losses on the system. It is possible however to determine the most favourable allocation of variable losses to be zero, in which case the party would only pay for its uniform allocation of fixed losses.

It has been suggested that national grid could calculate a single set of zonal TLFs for each year and to supplement this with a mandatory hedging scheme for some users.

Table 33: Zonal Losses

Zonal Losses	
Uniform or locational	Locational allocation of variable losses Uniform allocation of fixed losses
Marginal V's average	Marginal
Ex-ante v's ex-post	Ex-ante
Single v's multi part	Single Loss factor applied The methodology could be adapted to produce multi-part loss factors so for example different loss factors apply to each season.
Dispatch Scenarios	Considers one snapshot of the network during a previous period that provides a representation of the applicable period. Renewable generators treated in same way as conventional generators Not stated how interconnectors are treated.
Period of Application	Published 3 months in advance of the year to which they apply.
Fixed or Non-fixed	Fixed losses allocated locationally Non-fixed losses allocated uniformly
Incumbent V's new entrant	Incumbents and new entrants treated equally
Purchased V's adjustment fixed	Adjustment factor applied to recover cost of losses
% of losses applied to generators and suppliers	45 % recovered from generators 55% revenue recovered from demand
Likely implementation date	Q4 2010

11. Mexico: Tariff methodology

Overview

The paper "Assessment of Transmission Pricing schemes based on short term marginal costs" published by Cigre (reference C5-209) sets out details on the methodology adopted in Mexico.
This paper presents the evaluation of alternative transmission pricing methods, particularly those which could be applied under the current structure of the Mexican electricity sector.
The purpose of the paper was to provide policy makers with information for the assessment of alternative transmission pricing schemes, the authors applied alternative pricing methodologies and calculated the transmission charges to producers, consumers and point to point wheeling transactions.
The pricing schemes studied share a pricing scheme that recovers the revenue requirement through congestion rent and the complementary revenue that is collected by means of an access service charge that is applied to transmission customers.

A mega watt mile variant is used to set transmission tariffs in the Mexican Spot Market.

Tariff Regime

Assumes the pricing includes the following components

1. Variable energy charge that captures cost of congestion transmission losses and energy imbalance.
2. Access charge that allocates complementary revenue amongst network users
3. Connection charge that covers the local connection costs and any reinforcement of network to accommodate transaction.
4. A generation capacity charge that covers the cost of marginal transmission losses as well as generation imbalance.

All constitute economic signals about efficient location of new load and generation.

Methodologies Studied

1. Pro rata determined by the customers share of the monthly coincident peak load (postage stamp)
2. Pro rata determined by customer share of the estimated societal benefits provided by the transmission network (benefit factors)
3. Pro Rata determined by a variant of the MW mile method (Modified reverse MW mile)

Benefit factors refer to the calculation of the benefits that a particular network corridor is worth for consumers and producers, this requires computation of spot prices assuming the corridor doesn't exist.

Consumer benefit is reduction in monetary value of energy consumption due to existence of the corridor. Producer benefit is the increment in net revenues due to the existence of the corridor.

Reflects cost of inclusion of the inclusion i.e. power flow due to wheeling and power flow without that transaction.

Differs from MW mile method as it takes into account the reduction in use of system as a result of the transaction.

Table 34: Mexican Tariffs

Mexico Tariff Methodology		
1	Deep versus Shallow Charging	Deep charging policy
2	Load flow V's Postage stamp	Load Flow with postage stamp element
3	Dispatch / Scenarios	81 different case studies were applied from a combination of demand growth, fuel prices, hydroelectric energy availability

		and potential delays in commissioning transmission or generation assets.
4	Energy V's capacity	Combination of energy and capacity related charges.
5	Demand / generation split	Not defined
6	Costings approach (RAB and within model)	1. Variable energy charge that captures cost of congestion transmission losses and energy imbalance. 2. Access charge that allocates complementary revenue amongst network users 3. Connection charge that covers the local connection costs and any reinforcement of network to accommodate transaction. 4. A generation capacity charge that covers the cost of marginal transmission losses as well as generation imbalance
8	Volatility Mitigation Technique e.g Capping	Uses a "Financial Transmission Contract Framework" to mitigate volatility – no further details outlined
9	Network Optimisation	Not defined
10	Scaling e.g Delta Multiplier	Not defined
11	Zonal v's Nodal	Nodal
12	Asset included e.g System support Cap Banks	Not defined
13	Period of interest	Daily on an hourly basis due to spot market arrangement.

14	Implementation Date [complex versus non-complex]	Post 2010

12. Malaysia Tariff Methodology

Cigre paper reference 37-204 details the methodology adopted in Malaysia.

Tariff Regime

In Malaysia the current Connection Policy determines that IPPs pay for construction of all facilities required to connect to transmission system. Existing generators/new generators that are constructed in accordance with grid code don't have to pay use of system, the planning process recognises system needs and constraints. Generators outside of the plan have charges formulated on an ad hoc basis.

Paper examines different options

1. Embedded cost – revenue requirement
2. Short run marginal cost – cost of providing additional unit of service with existing facilities.
3. Long run marginal cost – cost of providing additional unit of service where this would require expansion of the capacity of the system.

LRMC selected as the most appropriate approach.

- Costing principle applied over long term period usually 5-10 years incorporating future annual investment costs including O&M costs and losses.
- Uses annual incremental demand to yield cost for additional 1kW power in system.
- Encourages buyers and sellers to optimise operation.
- Good performance indicator for decision makers to decide on what would be the fair returns on the investment.

Potential to have zero price when there is no growth or decline in demand, however it is still necessary to recover depreciation of assets and costs of operation and maintenance.

Two scenarios – Future or Current Customers

To avoid over/under recovery a reconciliation of LRMC based prices against revenue requirements is necessary.

Approach

1. LRMC prices established
2. Revenue established
3. Assumes power flow uses whole network
4. No "simple" way to determine changes in investment versus usage as investments can be "lumpy"
5. Table of costs of investment versus change in load level through system created.

Calculation of LRMC

Calculated in respect of change in MW of load based on:

- Maximum demand
- Total investments in assets
- O&M costs
- Averaged discounted rates
- Average incremental capacity costs or AMC

AMC is the investment required in transmission capacity to provide for 1KW increase in the system. AMC is calculated based on the fact that the investments and related costs must be met by the incremental demand cost over the period of review. AMC equals present value of investment cost divided by present value of demand

AMC is annuitized through life of assets by computing AFCR.
AFCR (annual fixed carrying charge rate) this is the annual rate of owning cost to an investment through the life of the investment (fixed and variable costs).

LRMC = AMC * AFCR

Development of MW distance prices doesn't use load flow.

Uses straight line distance between identified load centres and all generators. Weighted distance for each load is then developed by considering different dispatch patterns.

The methodology assumes each load centre will receive power with same proportion as the proportion of output of each generator in the system. This gives the relative distance of each load centre to an equivalent point of all generators.

Distance based use of system prices can be determined by dividing the reconciled rate with average system distance.
For max demand price Coincidence factor introduced.
Peak at different load centres may not be in line with timing of max demand peak. The coincidence factor determines % contribution of a load centre to the system peak.

Cost of Losses

Information on the treatment of losses in Malaysia was not available.

Table 35: Malaysian Tariff Model

Malaysia Tariff Methodology		
1	Deep versus Shallow Charging	Deep charging policy – only those not complying with planning policy – i.e. those who don't locate in line with planning policy pay TUoS
2	Load flow V's Postage stamp	Load Flow – MW distance
3	Dispatch / Scenarios	Peak demand
4	Energy V's capacity	Capacity
5	Demand / generation split	Not Defined
6	Costings approach (RAB and within model)	Costing principle applied over long term period usually 5-10 years incorporating future annual investment costs including O&M costs and losses. Uses annual incremental demand to yield cost for additional 1kW power in system.
8	Volatility Mitigation Technique e.g Capping	Not defined
9	Network Optimisation	Not defined
10	Scaling e.g Delta Multiplier	Not Defined
11	Zonal v's Nodal	Zonal
12	Asset included e.g System support Cap Banks	All transmission assets used in calculation.
13	Period of interest	Tariffs calculated on ad hoc basis
14	Implementation Date [complex versus non-complex]	Q4 2010

13. Current TUoS methodologies in NI & ROI

Current Generator TuoS tariff methodology applied in Northern Ireland

Purpose

The aim of the generator export capacity charges is to recover the appropriate 25% share of the approved annual transmission entitlement from generators who use the transmission system to export their energy to meet demand. A uniform tariff is levied on generators based on their export capacity as this is deemed to be a transparent and stable method of recovering the required revenue from parties using the transmission system.

Tariff Methodology

Generators pay an export tariff based on their agreed contracted export capacity, as set out in their Transmission Use of System agreement or Connection agreement. The level of the generator TuoS tariff is determined by two factors, the first of these is the amount of the annual Transmission Revenue Entitlement. The Transmission Entitlement revenue is calculated as a percentage of NIE's Transmission and Distribution Entitlement, which is prepared and submitted to NIAUR by NIE and approved by NIAUR. The second factor which determines the level of TUoS charge is the amount of generation capacity connected to the system which shall be liable for charges in the revenue period, this is referred to as the total chargeable capacity. The total chargeable capacity is a sum of the contracted capacity of all generators connected to the transmission system and those connected to the distribution system who have a contracted capacity equal to or greater than 10MW.

The generator export tariff is a uniform tariff which SONI calculate by dividing the target amount of annual revenue which is to be recovered from generator TUoS charges by the total chargeable capacity of all generators. The tariff methodology does not take into account the location of generator. All generators pay the same £/MW/month charge irrespective of where they are located on the network. Similarly, all generator types pay the same tariff irrespective of whether the generation is conventional or non-conventional.

Generators who import from the transmission system also pay the relevant generator import charges which consist of a standing charge and a number of energy based charges. The current charges for 08/09 are outlined in Schedule C in SONI's Statement of Charges document available on www.soni.ltd.uk.

Table 36: NI Generator Tariffs

Features of the current Northern Ireland Generator TUoS Tariff model	
Deep versus Shallow charging	Shallow connection policy (previously deep)
Locational or Postage stamp tariffs	100% Postage stamp
Energy or Capacity based Charge	100% Capacity based charge
Demand / Generation revenue split	25% revenue recovered from generator tariffs 75% revenue recovered from supplier tariffs
Costings Approach	Not Applicable
Dispatch scenarios	None, model is not load flow based
Volatility Mitigation Techniques e.g. Capping	None
Network optimization	Not Applicable
Scaling	No. Not necessary
Zonal v's nodal	Not Applicable. One charge applies to all generator units
Assets included	Not Applicable
Period of Application	Calculated each year for a 12 month period

Current Supplier Tariff Model applied in Northern Ireland

Background

Until 2008 demand TUoS Tariffs have been calculated by NIE T&D on behalf of SONI using a single tariff model to derive both Transmission and Distribution use of system charges. In March 2008 the transmission component of this model was provided to SONI and was used to derive the demand TUoS charges for the tariff period 1st October 2008 to 30th September 2009. For this reason the current TUoS charges have a similar charging structure as the Distribution Use of System charges in NI.

Purpose

The aim of the Demand TUoS tariff is to recover a given revenue amount associated with the costs of building, operating and maintaining the NI transmission network. The current charging regime aims to recover 75% of total Transmission Entitlement for NI from all demand users. Obviously it is not possible to charge every individual customer based on the precise cost they impose on the network therefore several classes of customer are grouped and customers are charged based on the schedule of tariffs applicable to their class.

Energy Forecast & Profile data

The tariff model uses energy forecast data and profile data outlining the characteristic spread of demand across each tariff group. The energy forecast is an extremely important element of the tariff derivation process as this is a key determinant in the new tariff rates. Regression analysis is used to create an energy forecast for the tariff year for each of the high level groups.

Tariff Methodology

The objective of the tariff model is to attribute network capital costs and operating costs to the various users of the transmission system in proportion to the estimated usage that these users make of the transmission system. In order to do this, details of the network costs and operating costs are obtained and these are then scaled back to equal the revenue that NIAUR has approved to be recovered. In addition, details of the system load at the various voltage levels is required to determined the usage that customers connected at these voltage levels make of the transmission system. Costs are then allocated to the various voltage levels using two methods, network capital costs are allocated based on estimated peak usage only, therefore are allocated to only the two peak timebands in each customer connection level. Load related operating costs are allocated to all timebands based on estimated load duration. A total cost is then summed for each timeband at each of the customer connection levels. In order to determine a single cost for relevant tariff category profile allocations are used. Supplier tariffs are recovered based entirely on energy usage. The tariff methodology does not take into account the location of suppliers, all suppliers within the same tariffs category pay the same charges irrespective of where they are located on the network. Ten different schedules of tariffs are produced, these are published in SONI's Statement of Charges document available on www.soni.ltd.uk.

Table 37: NI Demand/Supplier Tariff Model

Features of the current Northern Ireland Supplier TUoS Tariff model	
Deep versus Shallow charging	Presently used with a Shallow connection policy. Previously was used with deep connection policy
Locational or Postage stamp	100% Postage stamp at each connection level.
Energy / Capacity based Charge	100% Energy based charges
Demand / Generation revenue split	75% revenue recovered from demand tariffs 25% revenue recovered from generator tariffs
Costings Approach	MEAV used as replacement network costs
Dispatch scenarios	None, not load flow based
Volatility Mitigation Techniques e.g. Capping	None
Network optimization	Not Applicable
Scaling	No
Zonal v's nodal	Not Applicable
Assets included	All 275kV & 110kV transmission assets
Period of Application	Calculated each year for a 12 month period

Current Generator TUoS tariff methodology applied in Republic of Ireland

Background

The current methodology was introduced in 2001. Before that the ESB as the vertical integrated utility used an alternative arrangement. The changes were introduced along with the Shallow Charging policy.

Purpose

This is to recover revenue required for the effective planning and operations of the Republic of Ireland Transmission System. The arrangement should also provide a signal identifying the locations which are most efficiently situated from the Transmission System perspective.

Tariff Methodology

(1) the use of each circuit by each generator is determined using load flow analysis. This analysis requires the specification of generation and demand at each point on the network. The load flow study then calculates the flow of all power from generators to demand sinks, based on peak load conditions.

(2) transmission assets are valued based on replacement costs. The cost of each circuit includes a depreciation charge, operations and maintenance overheads plus an appropriate rate of return. Station costs are apportioned to each line connecting into that station on a per bay basis. Only lines where more than 20% of their rated capacity is used are included in the model.

(3) Generators are charged for each circuit in direct proportion to their contribution. A key feature of the Reverse MW-mile approach is that generators which off-set flows are rewarded, by crediting counter-flows. Due mainly to the lumpiness of transmission investment, at any given point in time, spare capacity (i.e. differences between the rated capacity of an asset and the extent to which is used by all network users) will exist on the transmission system. The cost associated with the spare capacity on all circuits is averaged across all users (as opposed to charging the full cost of a circuit to the specific users of each circuit).

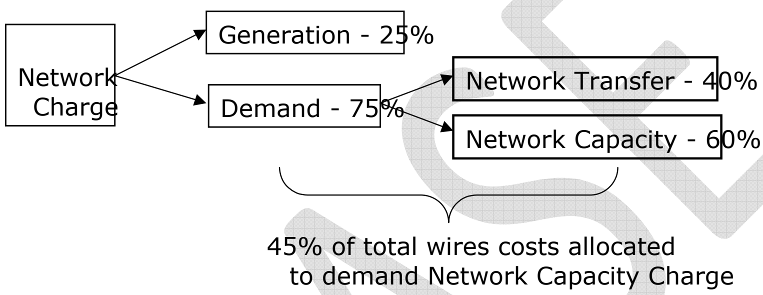
Table 38: Generator Tariffs in ROI

Features of the current Generator TUoS tariff methodology applied in ROI	
Deep versus Shallow charging	Presently used with a Shallow connection policy.
Locational or Postage stamp	Approx 80% Locational 20% Postage Stamp
Energy / Capacity based Charge	If firm 100% Cap if non-firm energy
Demand / Generation revenue split	75% revenue recovered from demand tariffs 25% revenue recovered from generator tariffs
Costings Approach	Current Replacement Cost of Assets
Dispatch scenarios	Pro-rata at Winter Peak
Volatility Mitigation Techniques e.g. Capping	Lightly used lines are taken out
Network optimization	Not explicitly done
Scaling	Delta
Zonal v's nodal	Nodal
Assets included	440, 220 & 110kV transmission assets
Period of Application	Calculated each year for a 12 month period

Supplier/Demand

Network Charges are primarily related to recovery of wires costs. These recover the costs for the use of the transmission system infrastructure for the transportation of electricity in Ireland. 75% of the total wires related costs are recovered from demand users and the remaining 25% from generators, see Figure below.

Figure 1: Breakdown of Network Charges in Republic of Ireland



System Services Charges relate to the recovery of non-wires costs. These recover the costs arising from the operation and security of the transmission system. Specifically, these charges recover the costs associated with ancillary services and system support services. EirGrid pays the costs of these services to the providers of such services and users pay EirGrid a System Services Charge in respect of these costs.

Table 39: Demand Tariffs in ROI

Demand TUoS tariff methodology applied in ROI	
Deep versus Shallow charging	Presently used with a Shallow connection policy.
Locational or Postage stamp	Postage Stamp
Energy / Capacity based Charge	60% Capacity 40% Energy for network charges and 100% Energy based for System Services

Demand TUoS tariff methodology applied in ROI	
Demand / Generation revenue split	75% network revenue recovered from demand tariffs 25% network revenue recovered from generator tariffs 99+% System Services from demand customers
Costings Approach	Not Applicable
Dispatch scenarios	Not Applicable
Volatility Mitigation Techniques e.g. Capping	Not Applicable
Network optimization	Not Applicable
Scaling	Not Applicable
Zonal v's nodal	Not Applicable
Assets included	Not Applicable
Period of Application	Calculated each year for a 12 month period

14. Details of respondents to questionnaire and call for industry papers

List of respondents to Questionnaire

- Irish Cement Ltd
- Airtricity
- IWEA
- Constant Energy
- Eco Wind Power Ltd
- Rusal Aughinish
- Energia
- ESB Customer Supply
- ESB Independent Generation
- Saorgus Energy Ltd
- ConocoPhillips, Whitegate Refinery
- Premier Power Limited
- NIE Energy (Supply)
- Bord Gais
- Enercomm International
- AES
- ESB Wind Development
- NIE Energy Limited, Power Procurement Business
- Synergen Power Ltd
- Merck Sharp & Dohme
- Viridian Power and Energy
- Tynagh Energy Limited
- Bord na Móna Energy Ltd
- Schering Plough (Brinny) Co Ltd
- First Electric Ltd
- Boliden Tara Mines
- Shannon LNG
- MASONITE IRELAND
- Moyle
- ESB Independent Energy
- Vayu
- SWS
- Lisheen Mine
- Irish Grid Solutions

- Quinn Group

List of companies that submitted Industry Papers

- Airtricity
- ESB Customer Supply
- ESBIE
- IWEA
- Saorgas
- SWS
- Synergen
- Viridian Power and Energy