Technical Working Group Report

Significant Code Review

Project TransmiT: Electricity Transmission Charging Significant Code Review

Initial Report of the Technical Working Group

September 2011

This document contains the discussion of the Electricity Transmission Charging SCR Technical Working Group which formed in July 2011 and constitutes the key deliverable of the Working Group, as set out in the group's terms of reference. It will form an input into the Ofgem December 2011 Significant Code Review Consultation.

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Contents

About this document

This document is the key deliverable of the Electricity Transmission Charging SCR, Technical Working Group. It documents a summary of the relevant discussions and conclusions of the group arising through the development of a Status Quo, Improved ICRP and Postage Stamp charging model to be taken forward into economic modelling. The results of this impact assessment and this Working Group report, as well as an additional 'Final Report', will form an input into the December 2011 Ofgem SCR consultation.

Further detail on Project Transmit, the Significant Code Review and the activities of the Working Group can be found on Ofgem's website at:

http://www.ofgem.gov.uk/Networks/Trans/PT/Pages/ProjectTransmiT.aspx

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1	13 August 2011	Working Group	Initial Outline
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Any Questions?

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1 Executive Summary

1.1 Following a consultation in July 2011, under the banner of Project TransmiT, Ofgem launched a Significant Code Review (SCR) focused on the charging arrangements that seek to recover the costs of providing electricity transmission assets; i.e. Transmission Network Use of System (TNUoS) charging.

1.2 Currently TNUoS charges are calculated by National Grid as National Electricity Transmission System Operator (NETSO) in accordance with the GB Use of System Charging Methodology[1], put in place on 1 April 2005. Changes to the methodology are subject to the Connection and Use of System Code (CUSC) governance process[2].

1.3 In accordance with National Grid's Transmission Licence Condition C5, charges are currently calculated (and changes assessed) in accordance with the relevant objectives, which state that charges should (paraphrased for convenience):

(a) Facilitate effective competition in the generation and supply of electricity;

(b) Reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses;

(c) Properly take account of the developments in transmission licensees' transmission businesses.

1.4 In addition to the relevant charging objectives above, the Transmission Licence (Standard Licence Condition C7) also prohibits National Grid from discriminating against any User or class of Users unless such different treatment reasonably reflects differences in the costs of providing a service.

1.5 The basis for the current charging methodology is the Investment Cost Related Pricing (ICRP) approach, which calculates TNUoS tariffs that vary according to the incremental cost of supplying network capacity at different locations. The principle behind this approach is one of providing economic signals that allow users to factor their impact on the transmission network on siting decisions and hence provide an overall economic generation and transmission system for end consumers.

1.6 As part of the SCR launch, Ofgem set out to establish a Working Group in order to develop the technical detail of two alternative approaches to TNUoS charging. These approaches, a 'Postage Stamp' model and an 'Improved ICRP' model, are to be assessed alongside the existing ICRP model in an impact assessment by Ofgem's appointed economic consultants, Redpoint Consulting Limited. Ofgem also indicated that connection charging arrangements, embedded generation and the small generator discount (Standard Licence Condition C13) are out of scope of the SCR.

1.7 The Working Group, comprised of fifteen representatives covering a broad range of stakeholder interests, met on a fortnightly basis between July and September 2011 in order to discuss and develop the aforementioned models. The deliberations of the Working Group focused around six broad themes, categorised by Ofgem as follows:

What was the primary task of the Technical Working Group?

Over the course of six meetings the Working Group was tasked with developing an Improved ICRP and a Postage Stamp charging model and, along with a Status Quo model, make recommendations for how these should be treated in the impact assessment for the Significant Code Review.

[1] Section 14 of the Connection and Use of System Code, http://www.nationalgrid.com/NR/rdonlyres/8FFA9408-9DC7-44C2-AF68-93E684A176D8/47549/CUSC_Section_14combinedmasterclean5July11_FINAL.pdf

[2] Section 8 of the Connection and Use of System Code, http://www.nationalgrid.com/NR/rdonlyres/8B81E9A0-F1B1-47B7-906D-41DA0DB69167/45131/CUSC_Section_8_v19_CAP179_WGAA2_31Jan11.pdf

Theme
1. Reflecting characteristics of transmission users
2. Geographical/topological differentiation of costs
3. Treatment of security provision
4. Reflecting new transmission technology
5. Unit cost of transmission capacity
6. G:D split

1.8 In addition to model development, the Working Group was also given the opportunity to comment on the input assumptions to the economic modelling exercise being undertaken in parallel by Redpoint. In September, as a result of industry feedback, Ofgem decided to extend the remit of the Working Group to provide feedback on the outputs of the economic modelling work. These elements are not included in this initial report, but will be included in a later final report.

1.9 Over the course of six meetings, each of the six themes and implementation issues were discussed. In addition, an update of progress was provided to a stakeholder engagement session hosted by Ofgem in August.

1.10 The Working Group highlighted early on in the process that it may be difficult to achieve consensus, given the broad range of interests represented. Ofgem noted that, where a consensus was not achieved, Ofgem would make a final decision on the detail to be taken forward for economic modelling.

1.11 The detail of the Working Group discussion and conclusions on each of the Status Quo, Improved ICRP and Postage Stamp charging models is covered in sections four to ten of this report. This is supplemented by additional material provided to the group in the course of meetings, included as Annexes to this report or online in Ofgem's TransmiT web forum[3].

1.12 The Status Quo model proposed by the Working Group uses the existing ICRP approach, including recommendations regarding the treatment of future HVDC 'bootstrap' and the split of revenue collection between generation and demand should be treated across the impact assessment modelling timeframe. The latter being a change from 27% generation and 73% demand to 15% generation and 85% demand in 2015 in order to avoid breach of EU tarification guidelines before 2020.

1.13 There was significant debate amongst Working Group members about what would constitute an Improved ICRP model. A model put forward by National Grid was used as a starting point for discussion.

1.14 The Working Group reached consensus on the inclusion of a dual background approach in the charging model, which would recognise that incremental transmission network costs are driven by both 'peak security' and 'year round' conditions (as opposed to the existing focus on peak conditions only). This approach is consistent with the current proposals to change the NETS SQSS and would result in a two part locational tariff.

1.15 No consensus was reached on the applicability of the aforementioned tariff elements to different generation types or the charging units to be used when calculating individual user charges (i.e. MW, MW multiplied by load factor or MWh).

[3] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Pages/WebForum.aspx

1.16 The proposed treatment of HVDC ‘bootstrap’ links and the split of transmission revenue collection between generation and demand in the status quo model would also be applied to the Improved ICRP model.

1.17 The Working Group’s views on what form of Postage Stamp model should be taken forward into impact assessment also varied widely. Views were split between those who believed that a Postage Stamp approach should socialise all infrastructure costs and those who believed that some elements of cost-reflectivity may still be appropriate (e.g. for local circuits and/or demand charges).

1.18 No consensus was reached on whether any elements of a Postage Stamp model should remain cost-reflective or on what charging units, whether MW, MW multiplied by load factor or MWh, would be most appropriate

1.19 The Working Group also discussed issues of implementation and transition. The debate in this area considered issues from the perspective of generators, suppliers, the system operator and consumers. The view of the group was that all parties would be affected in one way or another and that, as such, sufficient notice of change prior to implementation would be beneficial in order to avoid creating windfall gains and losses.

1.20 On implementation the Working Group concluded that most benefits to sustainability and security of supply would occur as a result of a timely decision on the eventual form of any changes, rather than their immediate implementation. This was because generation developers would be unable to speed up their projects in the short term, but could delay as a result of uncertainty surrounding the outcome of Project TransmiT.

1.21 There was a consensus amongst Working Group members that April 2013 would be the earliest feasible implementation date, with April 2014 being considered as preferable.

2 Background

Project TransmiT

2.1 Project TransmiT is Ofgem's independent and open review of transmission charging and associated connected arrangements. The aim of Project TransmiT is to ensure that arrangements are in place to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers.

2.2 Ofgem launched a Call for Evidence[4] on 22 September 2010, inviting views on the scope of and priorities for the Project TransmiT review and called for evidence from generators, shippers, suppliers, network companies, consumers and their representatives, the sustainable development community and other interested parties. Ofgem anticipated, at that time, coming to a conclusion in the summer of 2011.

2.3 The review initially incorporated charging and connections arrangements for electricity and gas as well as consideration for Carbon Capture and Storage.

2.4 In their scoping document[5] of 25 January 2011 Ofgem clarified the scope of Project TransmiT. After considering responses to the Call for Evidence and views expressed at a stakeholder event, electricity connection issues and electricity transmission charging arose as the immediate priority.

2.5 In parallel, Ofgem commissioned a series of reports from consultants and academics to gather evidence focused on the electricity transmission charging regime, with consideration for interactions with the gas regime and consistency of key principles. These reports were published on the Project TransmiT web forum[6] in May 2011.

2.6 Also in May 2011, Ofgem published an open letter[7] setting out their approach to work on electricity charging under Project TransmiT. In this letter Ofgem set out that the charging work under Project TransmiT would focus specifically on charging arrangements that seek to recover the costs of providing electricity transmission assets; i.e. Transmission Network Use of System (TNUoS) Charging.

2.7 In addition the aforementioned May open letter set out the view that this work should be progressed through a Significant Code Review (SCR) and that the approach was consistent with the original scope of Project TransmiT, which is seeking to address issues that are an immediate priority, and should enable any appropriate changes to be introduced in the short term. Ofgem noted they hoped to come to a conclusion in late summer 2011 and that, if appropriate, the aim would be is to implement any change to TNUoS in time for the next charging year; i.e. April 2012. However, they recognised that this is an ambitious and challenging timetable and therefore did not rule out the possibility of implementing appropriate changes at a later date. Ofgem have since confirmed that changes, where appropriate, will be implemented after April 2012 to allow for further analysis[8].

2.8 In assessing the need for an SCR, Ofgem have considered the following criteria:

What is Project TransmiT?

Ensure that arrangements are in place to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers.

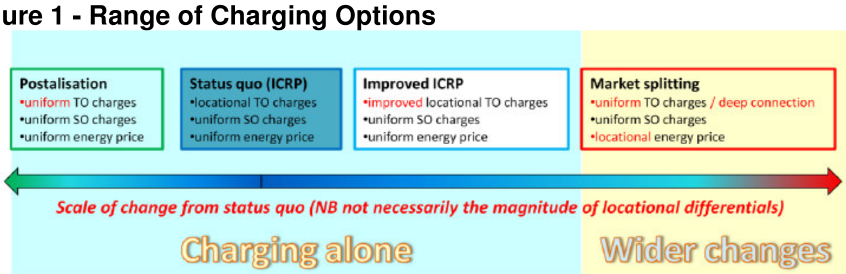
4 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/Trans/PT
5 http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110125_TransmiT_Scope_Letter_Final.pdf
6 http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Pages/WebForum.aspx
7 http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110527_TransmiT_charging_letter.pdf
8 http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110909_TransmiT_charging_SCR_update.pdf

- The solution to the issues raised by the area of work can be given effect wholly or mainly through code changes;
- The Authority consider those issues are significant in relation to its principle objective and/or its other statutory duties and functions, or due to the obligations arising under EU law, in particular:
    - There is likely to be significant impacts on gas and electricity consumers or competition; and/or
    - There is likely to be significant impacts on the environment, sustainable development or security of supply; and
- The area of work is likely to create significant cross-code or code-licence issues.

2.9 Following a consultation in July 2011, Ofgem announced their intention to launch an SCR[9] on electricity transmission charging issues under Project TransmiT and to conclude by December 2011. The launch statement set out the timetable and next steps for the SCR, making clear that collaborative and constructive input from industry is essential to timely delivery of any appropriate changes. In its open letter of September 2011 Ofgem indicated that the timetable would be extended to March 2012.

2.10 The scope of the SCR is to develop and assess a range of charging options that focus on TNUoS charging alone and therefore exclude options that imply wider changes (i.e. those that would, to varying degrees, impact the current GB electricity trading arrangements). This range is illustrated in Figure 1, below.

Figure 1 - Range of Charging Options



2.11 The scope of the Project TransmiT SCR also excludes any changes to the charges that recover the cost of system operation (i.e. Balancing Services Use of System (BSUoS) charges) and charges that recover the cost of connection (connection charges). were also excluded from the scope of the Project TransmiT SCR.

2.12 To assist in the deliberations of the SCR, the relevant issues to be addressed by the SCR were categorised into 6 broad themes by Ofgem:

Table 2-1 - TNUoS Charging Themes

Theme
1. Reflecting characteristics of transmission users
2. Geographical/topological differentiation of costs
3. Treatment of security provision
4. Reflecting new transmission technology
5. Unit cost of transmission capacity
6. G:D split

[9] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110707_Final%20launch%20SCR%20statement.pdf

2.13 In order to achieve the SCR objectives Ofgem specified two parallel initiatives:

- Detailed modelling work, undertaken by Redpoint Consulting with support from National Grid Electricity Transmission (NGET), in order to identify the likely impacts of the different potential options for change; and

- A technical Working Group to support the development of the technical detail of potential options for TNUoS changes.

2.14 The focus of this report is to capture the discussion and conclusions arising out of the technical Working Group. Further details on the purpose and structure of the Working Group can be found in Section 3, Annex 1 and Annex 2 of this report.

2.15 The intention of this report is to serve as an input into Ofgem's consultation on the outcomes of the SCR in December 2011 and ultimately Ofgem's Spring 2012 SCR conclusion, which may lead to an SCR direction being issued to raise code changes.

Electricity Transmission Charging

2.16 As the holder of Transmission Licences in Great Britain, the GB transmission licensees are required by the Electricity Act 1989, as amended by the Utilities Act 2000 and the Energy Act 2004, to develop and maintain an efficient, co-ordinated and economical system of electricity transmission and to facilitate competition in the generation and supply of electricity. The transmission licensees are also required by Schedule 9 of the Electricity Act to have regard for the effects of its activities on the environment.

2.17 As part of the implementation of the British Electricity Trading and Transmission Arrangements (BETTA) a GB transmission use of system charging methodology was put in place on 1 April 2005.

2.18 The GB Use of System Charging Methodology has the following objectives as set out in the Transmission Licence Condition C5 which requires:

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

b. that compliance with the Use of System Charging Methodology results in charges which reflect, as far as reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses;

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

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

2.20 In addition to the relevant charging objectives above, the Transmission Licence (Standard Licence Condition C7) also prohibits National Grid from discriminating against any User or class of Users unless such different treatment reasonably reflects differences in the costs of providing a service.

2.21 As part of the Connection and Use of System Code[10] (CUSC), the modification process for the Use of System Charging Methodology is subject to the CUSC amendment procedure as set out in Section 8 of the CUSC.

Existing TNUoS Charging Principles

2.22 Transmission Network Use of System (TNUoS) charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) activity functions of the transmission businesses of each GB Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

2.23 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System charges are set to recover the annual Maximum Allowed Revenue as set by the price control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

2.24 The basis of transmission charging to recover the allowed TO revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by National Grid in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the National Grid document "Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)".[11]

2.25 In April 2004 National Grid introduced a DC Loadflow (DCLF) ICRP based transport model for the England and Wales transmission charging methodology. The DCLF model has been extended to incorporate Scottish transmission network data with existing England and Wales transmission network data to form the GB network in the model. The new GB charging methodology implemented in April 2005, incorporated the following changes:

- The application of multi-voltage circuit expansion factors with a forward-looking Expansion Constant (i.e. £/MWkm cost of transmission capacity) that does not include substation costs in its derivation.
- The application of locational security costs, by applying a multiplier to the Expansion Constant reflecting the difference in cost incurred on a secure network as opposed to an unsecured network.
- The application of a de-minimis level demand charge of £0/kW for Half Hourly and £0/kWh for Non Half Hourly metered demand to avoid the introduction of negative demand tariffs (note: this collar is not triggered, given the current level of tariffs).
- The application of a 132kV expansion factor on a Transmission Owner basis reflecting the regional variations in network upgrade plans.
- The application of a Transmission Network Use of System Revenue split between generation and demand of 27% and 73% respectively.
- A number of GB generation zones using the zoning criteria outlined in the methodology (this has been determined as 20 for 2011/12).
- The number of demand zones has been determined as 14, corresponding to the 14 GSP groups.

[10] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/contracts/
[11] See ICRP Paper June 1992 at http://www.nationalgrid.com/uk/Electricity/Charges/usefulinfo/

2.26 The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy.

2.27 The Transmission Licence requires National Grid to operate the GB transmission system to specified standards. In addition, National Grid, along with other transmission licensees, is required to plan and develop the GB transmission system to meet these standards. These requirements mean that the transmission system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to this standard. It is this obligation that provides the underlying rationale for the ICRP approach; i.e. for any changes in generation and demand on the transmission system, National Grid must ensure that it satisfies the requirements of the Security Standard.

2.28 The Security Standard identifies requirements on the capacity of component sections of the transmission system given the expected generation and demand at each node, such that demand can be met and generators' Transmission Entry Capacities (TECs) accommodated. The derivation of the incremental investment costs at different points on the transmission system is therefore determined against the requirements of the system at the time of peak demand. The charging methodology therefore recognises this peak element in its rationale.

2.29 There is currently a proposal to change the SQSS, GSR009, which is currently undergoing an impact assessment. The intention of this proposal is to alter the way in which transmission investment on the main interconnected system is undertaken for a system with a significant amount of intermittent generation. It would result in a recognition that transmission investments are being driven by year round economic optimisation as well as peak demand conditions and is discussed further in paragraph 4.18.

2.30 In setting and reviewing these charges National Grid has a number of further objectives[12]. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
- be implementable within practical cost parameters and time-scales.

2.31 Further details about charging principles and the derivation of TNUoS tariffs and charges can be found at National Grid's website in section of 14 of the CUSC at:

http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/contracts

[12] The Use of System Charging Methodology, Chapter 1: Principles

3 The Technical Working Group

3.1 In the Project TransmiT GB electricity transmission charging SCR launch statement, Ofgem set out to establish a technical Working Group to support the development of the technical detail of potential options for TNUoS changes.

3.2 The Working Group is comprised of 15 representatives from a broad range of stakeholder interests with relevant technical expertise. Detail of Working Group members is included in Annex 1.

3.3 Within its remit the Working Group met on approximately a fortnightly basis from the week commencing 18th July 2011 till 9th September 2011 in order to discuss, debate and develop both a postage stamp and an improved ICRP charging model. There were also a number of developments to the existing model that needed to take place in order to model the Status Quo out to 2030 (such as the treatment of the HVDC links and charging for the Scottish islands).

3.4 The official Terms of Reference for the group is included in Annex 2.

3.5 The structure of the Working Group meetings was set up around Ofgem's six themes, as set out in Section 2, above.

3.6 At the first Working Group meeting, Ofgem clarified the purpose and remit of the group. It set out that the Working Group:

- is a group of technical experts convened to develop technical solutions and/or options for two 'strawman' charging models to be taken forward into the impact assessment work being undertaken by Redpoint Consulting;
- is not a lobbying or decision making body;
- is to focus on issues of immediate priority and to develop incremental and worthwhile changes that could deliver improvements in the short-term;
- will not attempt to second guess potential EU driven changes that could materialise in the medium term as these are unknown at this point in time;
- should note that the status-quo approach to charging is still on the table;
- should note that an implementation date of April 2012 is the desired outcome, but that this is still open for debate (note: this was subsequently updated due to the extension of the SCR process); and
- outputs would comprise of a Technical Working Group report and recommendations for strawman models for analysis.

3.7 The meeting schedule was as follows:

Table 3-1: Work Group Meeting Schedule

Meeting	Date	Issues Discussed
WG 1	19/07	- Overview of process, themes and future meetings
WG 2	01/08	- Redpoint overview of modelling approach - Group discussion on themes 1 and 2
WG 3	09/08	- Presentation on potential 'socialised charging' strawman - Group Discussion on themes 3 and 4
WG 4	18/08	- Group Discussion on themes 5 and 6
WG 5	30/08	- 'Tidy up' session across all 6 themes
WG 6	09/09	- Transitional issues - Draft initial report

What is the Working Group?

The TNUoS SCR technical work group is comprised of 15 individuals with relevant technical expertise representing a range of stakeholders.

Six official work group meetings were held through July, August and September 2011. These were augmented with ad-hoc technical meetings.

3.8 In between official Working Group meetings chaired by Ofgem, NGET held two ad-hoc meetings in order to set out in more detail proposals under theme 1 for an Improved ICRP model. These meetings were held as follows:

Table 3-2: Ad-hoc Meeting Schedule

Meeting	Date	Issues Discussed
Ad-hoc 1	28/07	- Overview of NGET proposal for theme 1 - Question and answer session on proposals
Ad-hoc 2	24/08	- Review of discounted options for theme 1 - Discussion of all remaining theme 1 options - Capturing of views and areas of consensus

3.9 In addition to the meetings outlined above, NGET made a presentation on behalf of the Working Group at the Project TransmiT SCR stakeholder event held in London on the 11th of August 2011.

3.10 In order to aid in the development of issues falling under the six themes, outlined in Table 2-1, and support debate on options for change within the limited time available, Working Group members produced a significant volume of presentations and technical papers. These can be found on Ofgem's website at:

http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Pages/WebForum.aspx

4 Summary of Theme 1 Working Group Discussion

4.1 This section summarises the Working Group discussions relating to Theme 1 – reflecting the characteristics of network users.

4.2 Currently, the underlying rationale behind TNUoS charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems.

4.3 This rationale is currently accounted for using the Investment Cost Related Pricing (ICRP) methodology which considers the incremental effect of generation and demand via a DC load flow (DCLF) based transport model.

4.4 As described in sections 2.27-2.29, it is the transmission licensees' obligation to comply with the SQSS which provides the underlying rationale for the ICRP approach.

4.5 In line with the SQSS, the derivation of the incremental investment costs at different points on the system is currently determined against the requirements of the system at the time of peak demand. The charging methodology therefore presently recognises this peak element in its rationale, and bases charges on a capacity rather than commodity basis.

What is Theme 1?

The first of the six TNUoS charging themes identified by Ofgem, Theme 1 recognises that the characteristics of those using the transmission network (predominately generation in the short term) is changing and seeks to ascertain if and how the charging methodology should develop to take this into account.

Issues and defects this theme seeks to address

4.6 To assist the Working Group, Ofgem compiled responses to their Project TransmiT Call for Evidence (September 2010) for the six themes under consideration. The responses given in Table 4.1 below relate to those responses relevant to Theme 1 – reflecting characteristics of network users.

4.7 Additionally National Grid presented, at an ad-hoc Working Group meeting, their thoughts on how the characteristics of network users can affect transmission investment requirements. In particular, National Grid noted the long term nature of transmission investment decisions, and the increasingly significant economic driver for efficient system development balanced against long term year round operational costs.

Table 4-1: Summary of Call for Evidence Responses Relating to Theme 1

Respondent	Issue / defect
DONG, RWE, Orkney Islands Council, Prospect	The current TNUoS methodology does not recognise that low load factor, intermittent generation requires less transmission investment to accommodate its output pattern than a conventional generator at a particular location. It is appropriate to investigate the continued application of a uniform scaling approach as a proxy for load factor across GB under the current charging mechanism.
NGET	The current TNUoS methodology does not recognise the possibility of sharing transmission capacity between generators (eg sharing of capacity to reflect increased volumes of variable generation).
SSE, Poyry, International power, Orkney Islands	Examine whether the contribution of the locational and socialised elements of the current TNUoS charging

Council, Pelamis wave power, Smartest Energy, Statoil	methodology should continue to be based on capacity and peak demand (eg replace existing capacity based cost signals with charges based on MWh for all or part of the charging mechanism).
Renewable UK, SCDI	The current TNUoS methodology does not recognise the potential impact on transmission cost that the operating characteristics of storage and peaking plant provide.

Improved ICRP Model

4.8 This section summarises the Working Group discussions relating to options that could be developed for use with an improved ICRP model.

4.9 A number of options were discounted at the start of the Working Group discussion. These included wider considerations involving changes to BSUoS charges and the introduction of a locational marginal pricing system. Given the scope of the Project TransmiT SCR is focused on TNUoS methodology only, any change to the current Transmission Entry Capacity (TEC) rights for users was also discounted from the deliberations of the Working Group. However, it was noted that an explicit sharing modification might be proposed in the future.

Options Discussed

4.10 National Grid presented a proposal for an improved ICRP model that sought to address the issues and defects described in Table 4-1. The purpose of their proposal was to stimulate debate within the Working Group. Full details of the proposal can be found in Annex 3 of this report. National Grid also produced a question and answer paper (also in Annex 3) in response to some of the queries raised during Working Group discussions on the National Grid proposal.

4.11 It was noted that there were areas in which the National Grid proposal could be made more reflective of a user's specific impact on transmission investment. Concerns were also raised at some of the assumptions made to arrive at National Grid's proposed methodology, particularly the linkage between load factor and transmission constraints.

4.12 The Working Group discussed National Grid's analysis of the relationship between load factor and constraints (presented in Section 2 of Annex 3) and noted the following points:

- The analysis presents a correlation which is based on a modelled approach to 2011-12 and not historical information. This model has also been utilised in the SQSS review group and as part of National Grid's stakeholder engagement in the recent RIIO Transmission Price Control Review process.
- A completely linear relationship does not exist in all cases across many of the charging zones and National Grid has shown that some degradation of the correlation is apparent as more wind generators connect to the transmission network in the medium to longer term when using its 'Gone Green' generation background assumptions.
- The relationship between load factor and constraints is a simplified one as the generation mix within each charging zone also has an effect on this relationship.
- Some members believed that the use of this analysis as evidence of a 'reasonable proxy' may not be fully justified as an improvement to ICRP.

- Other members noted that the use of a load factor in transmission charging, although a simplification, could represent an acceptable balance between increasing the cost-reflectivity of the ICRP methodology through taking into account the differing characteristics of transmission network users and resultant impact on the need for network investment, versus the stability and simplicity required in order to provide a predictable signal through tariffs.

4.13 Some further analysis was presented by National Grid demonstrating that its proposed Annual Load Factor (ALF) has a better correlation with constraints than TEC and some Working Group members agreed that this was therefore an improvement to the cost-reflectivity of ICRP. However, some members of the Working Group continued to believe that the simplification inherent in using load factor, such as ALF, as a reasonable proxy for the cost of supplying network capacity for users of the transmission system may not be a justified basis for the adjustment of transmission charges.

4.14 In addition some disagreed with the use of historic load factors to determine the future running patterns of generators (and thereby transmission charges). Generators take into account a number of factors when determining whether to generate; e.g. fuel, cost of carbon allowances, level of Carbon Price Support, weather conditions, etc. Historic load factors may not provide a good proxy for future running patterns, particularly in future years when greater wind generation is expected to be deployed. However, some Working Group members had a counter view that using a load factor may be a justified approach for better reflecting the usage and cost of the transmission system. National Grid explained that an historic load factor approach (i.e. ALF) was proposed as a proxy for assumptions used about specific generating plant at the time of planning transmission network capacity (which becomes a sunk cost at that point in time)

4.15 The National Grid proposal did provide a platform to discuss incremental improvements that could be made to the existing ICRP methodology. To aid clarity, these discussions have been broken down into constituent parts below.

Improvements to Transport Model Backgrounds

4.16 Under the present TNUoS methodology, a DC load flow calculation representative of system peak requirements is undertaken as the basis for future incremental transmission investment requirements. Generation is uniformly scaled to meet the expected GB peak demand.

4.17 It follows that the existing ICRP methodology assumes that transmission investment requirements are determined by the requirements of the system at time of peak demand. Mindful of respondents' comments to the Project TransmiT Call for Evidence, the Working Group discussed whether this was still the case, and there was a discussion regarding the linkage between the TNUoS charging methodology and the requirements of the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS)[13]. Transmission companies in Great Britain have a license obligation to plan and operate their networks in accordance with the NETS SQSS. It was accepted that within the existing NETS SQSS there is a requirement to consider not only transmission capacity requirements at peak demand periods, but also through the course of a year of operation.

[13] NETS SQSS v2.1 March 7th 2011; http://www.nationalgrid.com/NR/rdonlyres/FBB211AF-D4AA-45D0-9224-7BB87DE366C1/15460/GB_SQSS_V1.pdf

4.18 It was noted that there is an ongoing NETS SQSS proposal, GSR009[14], currently undergoing impact assessment and consultation, which is proposing to amend the criteria for assessment of the minimum transmission boundary transfer capability requirements[15].There was some discussion by the Working Group of the GSR009 proposal, with the group noting the opportunity to provide views via the impact assessment and consultation. GSR009 proposes revised criteria for the assessment of transmission investments to account for both peak demand requirements and a more economic assessment of transmission. It was noted by the group how the year round background condition within GSR009 acts as a proxy for a full CBA of transmission investments. The reflection of a full CBA within transmission charging was also discussed and the Working Group generally agreed that there was a balance between simplicity and accuracy; in particular, it may not be worth pursuing a level of accuracy much higher than other areas of TNUoS charging.

4.19 National Grid's proposal for an improved ICRP model used the analysis carried out for GSR009 as a basis for changing the ICRP background setting, to account for both peak security and year round backgrounds. Whilst this linkage was generally accepted, some members considered it was unfortunate that GSR009 had not yet been approved.

4.20 The Working Group generally accepted that there was merit in accounting for the dual (peak security and year round) backgrounds described in GSR009 within the Transport Model. . National Grid had proposed a change to the peak security background and the incorporation of a second background condition to be used alongside this. This second condition would scale generation dependent on technology, using figures developed by the NETS SQSS GSR009 review group. Additionally, National Grid had also proposed accounting for generation technology within the system peak background, as recommended by the GSR009 review group. These figures are summarised in Table 4-2 below. The advantage of this approach was cited as its relative simplicity.

Table 4-2 Proposed ICRP Generation Background Scaling Factors

Generator Type	TEC	Current Methodology	Peak Security Background	Year Round Background
Intermittent	5,460	65.5%	0%	70%
Nuclear & CCS	10,753	65.5%	72.5%	85%
Interconnectors	3,268	65.5%	0%	100%
Hydro	635	65.5%	72.5%	66%
Pumped Storage	2,744	65.5%	72.5%	50%
Peaking	5,025	65.5%	72.5%	0%
Other (Conventional)	61,185	65.5%	72.5%	66%
(source 2011/12 Transport Model)				

[14] NETS SQSS Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation – GSR009 Consultation Document v1.0 11th June 2010; http://www.nationalgrid.com/NR/rdonlyres/E22B1547-D4CC-4F88-AEEF-C76305718C25/41720/GSR009SQSSConsultation.pdf

[15] Minimum transmission capacity requirements in the Security and Quality of Supply Standard; http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/SQSS/Documents1/GSR009%20Impact%20Assessment.pdf (paragraph 4.4)

4.21 A suggested alternative approach by a Working Group member was the use of a more detailed methodology based on assessment of a number of backgrounds across the year. Whilst this was felt to give a more accurate representation of major network planning decisions, it was noted that such an approach would be much more complex and inconsistent with the GSR009 proposals.

Allocation of Transmission Circuits to Transport Model Backgrounds

4.22 The introduction of two backgrounds in the Transport Model necessitates changes to the calculation of the incremental costs of transmission investment. Under the present methodology, an incremental 1MW is added to each node on the system in turn (balanced by its removal at a nominated reference node) and the incremental effect of this 1MW on system flows as a whole is representative of the incremental transmission investment requirements.

4.23 The use of two backgrounds means that a decision needs to be made as to which background is deemed to be driving the need for transmission investment.

4.24 Two options were raised. National Grid's proposal suggested that the background causing the higher circuit flow in the Transport Model DC load flow would be deemed to be the triggering background; i.e. its output was binary in nature. An alternative was put forward by a Working Group member for proportional allocation of a circuit between backgrounds, the proportion being based on the level of flow under each condition.

4.25 The Working Group discussed both options. It was considered that the binary option arguably produced a more cost-reflective solution, and gave a better reflection of the investment decisions being made. The proportional option was believed to provide a more stable output, and it was argued by one member that its methodology was more consistent with the overall ICRP philosophy. Whilst it was noted that both methodologies had merits, the overall consensus was to recommend modelling the binary approach given that there was little evidence to suggest that one was demonstrably more appropriate than the other.

Conversion of Circuit MWkm to Tariffs

4.26 The outputs of the Transport Model are zonal MWkm and, using either methodology described above, separate MWkm would exist for the two proposed backgrounds, which would need to be converted into tariffs. Whilst there was general consensus that this would result in two wider zonal tariff elements, namely year round and peak security, there was much discussion as to the basis on which these two separate tariffs would be charged to generators, and which generator would be liable for each.

4.27 At a high level, there was agreement that tariffs could either be charged on the basis of (i) capacity (as exists under the current TNUoS arrangements), or (ii) commodity (as exists under the current BSUoS arrangements), or (iii) on a combination of both (i) and (ii).

4.28 There was a general view that both wider tariffs, namely year round and peak security, should be applied at some level to all generation users or, alternatively, consideration of an exemption from one of the two tariffs should be extended to other users.

4.29 A summary of the options is provided in, Table 4-3, below.

Table 4-3: Options Considered for Allocation of Tariff Components

Option	Intermittent		Conventional		All Plant
	Peak Security	Year Round	Peak Security	Year Round	Residual
A	×	✓	✓	✓	✓
B	×	✓	✓	✓ (excluding peaking plant)	✓
C	✓	✓	✓	✓	✓

4.30 National Grid presented to the group on the detailed steps that would need to be taken within both the Transport and Tariff Models to develop the final applicable tariffs for generation and demand. It was noted by some members of the group that the year round and peak tariffs could be re-referenced in different ways to ensure that the correct amount of revenue is recovered from these two tariffs. Whilst the current practice within the Model(s) is to only re-reference for the 27:73 G:D split, a methodology recovering no revenue on a net basis was also developed. National Grid has provided further details on the approach to be taken in Annex 3. The recommended approach was to maintain a re-referencing methodology using the prevailing G:D split (i.e. 27:73 in 2011/12).

4.31 The treatment of the two separate peak security and year round wider tariff elements is discussed separately below.

Peak Security

4.32 Several options were discussed for the levying of the peak security tariff. The first option was the continuation of charging on the basis of capacity (i.e. TEC) as per the existing TNUoS methodology. Charging on the basis of a user's contribution at peak, either ex-post or ex-ante, was also considered. It was recognised that such options could lead to perverse incentives not to generate at peak demand periods.

4.33 The National Grid option had suggested that intermittent generation should not be liable for the peak security tariff. The rationale behind this proposal was that it is consistent with the approach adopted in the NETS SQSS GSR009 proposal. Whilst it was generally accepted that wind would on average contribute less at peak demand times, there was a view from some members of the group that there was merit in a level of charge being levied on intermittent generation. A number of Working Group members questioned the rationale for the exemption, arguing that network investment would be required to accommodate intermittent generation at peak if it is located in an area with low generation diversity. Some Working Group members also argued that the historical wind output data provided by National Grid showing an average wind load factor of 5% at peak, rather than 0%, demonstrated that the peak tariff should be applied to intermittent generation. An alternative was suggested whereby intermittent generation would be charged on their ex-post contribution at peak.

Year Round

4.34 Following much discussion, five alternative options were drawn up for levying of a year round tariff. These are described below. Most options related, in some form, to the use of a generator's load factor as a proxy in combination with a generator's capacity in the form of TEC.

4.35 Several options proposed the use of historic generator operating data to make future operating assumptions. Questions were raised as to the validity of this approach given that changes to the future generation mix are likely to significantly change the operation of many plants. It was also considered by some members of the group that the use of load factors makes a user's tariff dependent upon some factors outside of their own control (such as cost of fuel, cost of carbon ,etc.).

4.36 It was suggested that, similar to National Grid's proposal for peak security, generation with extremely low load factors should not be liable for the year round tariff. One member noted that peaking plant, which did not drive any year round investment, would have a load factor of <0.5% (i.e. 1.5/8760 hours per annum) and therefore would not be exposed to (or receive) the year round element of the tariff in practice.

4.37 It was suggested that generic load factors could be developed for different generation technologies. These would be based on historic data. Generators within a technology class would be levied a charge based on this load factor multiplied by their specific TEC. It was noted that such an approach would be simple, but would not capture the wide range of operating regimes that can occur within a single generation technology class.

4.38 A suggestion was made that the year round background scaling (see Table 4.2) could be used in place of a generic load factor. It was argued that this would be consistent with the approach taken in the Transport model. Again, to determine a user's specific charge, it was proposed that these figures be multiplied by a user's TEC. However, some Working Group members considered that this option would also fail to account for different user's operating regimes within a generation class.

4.39 National Grid's proposal put forward the use of a user specific load factor rather than a generic load factor. Whilst being slightly more complex than a generic solution, account would be taken of an individual's operating regime. There was a discussion over the timescale used for deriving this figure. Longer timescales would mean greater stability of charges, but changes to a user's operating regime would take longer to filter into their TNUoS charge. Again, it was proposed to multiply this load factor by TEC to arrive at a user's TNUoS charge. Over time, use of a user specific load factor (such as ALF) would be broadly reflective of assumptions made when planning network capacity.

4.40 One Working Group member believed that, given the rapid pace of change in the generation mix and the consequent change in load factors to some plant, it may be more appropriate to use an average based on a shorter historical period (e.g. 2 years). This member believed that using a shorter historic basis is likely to better reflect current and future load factor than a longer one. This is especially valid for cycling plant which could see its load factors fall at a comparatively quick pace as more 'must-run' intermittent generation comes online. No justification was provided as to how a shorter period would better reflect assumptions made when planning network capacity.

4.41 A proposal was made that charges could be based on an ex-ante requested load factor, with an end of year reconciliation to balance against the user's actual load factor. It was noted that this would require some level of commercial incentive on the user to not provide an artificially low load factor. This proposal could also result in greater levels of transmission revenue recovery transferring between financial years due to the reconciliation process.

4.42 A suggestion was made that the year round tariff could be levied based on a user's output; i.e. MWh. This would require a reconciliation process that could be similar to that currently applied to BSUoS or potentially several processes through the year. It was commented that such a proposal may not be considered reflective of a long run investment charge. However, it could be considered more reflective of an individual user's operating behaviour.

4.43 The data that would be used in order to calculate a user's load factor or MWh output was also considered. Both the metered output of a generator and a generator's final physical notification (FPN - i.e. intended output prior to the majority of System Operator intervention) were considered. It was noted that a metered data approach would be somewhat easier to implement on the basis that it was readily available audited data. However, several members of the working group believed that any charge based on a generator's output (i.e. load factor or MWh) should be based on FPNs as, if constrained off in the balancing mechanism rather than generating, a generator would still receive income as if it had generated. The Working Group thought that this proposal had merit.

Postage Stamp Model

4.44 Working Group discussions for Theme 1, in the context of a postalised approach to charging, centred on the choice of charging unit. No further reflection of user characteristics was deemed appropriate.

Choice of Chargeable Unit

4.45 During its deliberations the Working Group identified three broad options for reflecting the characteristics of transmission users by way of a postalised charge, namely:

- capacity (MW); and
- capacity (MW) scaled by load factor, and
- energy output (MWh)

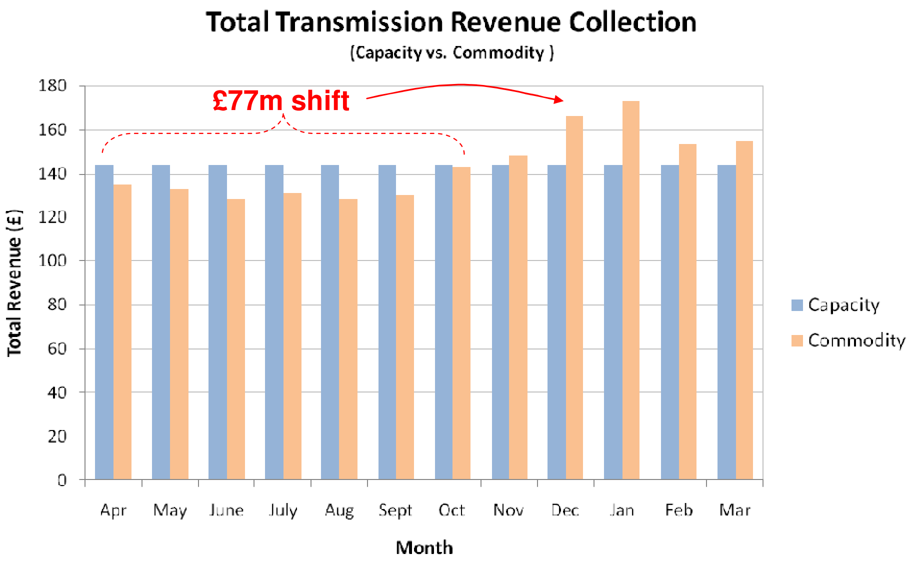
4.46 The group went on to consider that the chargeable unit for the purposes of setting tariffs and collecting revenue could either be based on ex-post commodity (MWh), ex-ante commodity (target MWh and reconciliation), ex-ante capacity (MW scaled or unscaled), or a combination of these.

4.47 The Working Group debated the practicality of the commodity based charge. Some noted that there was already an ex-post energy (MWh) charge for BSUoS. However, this was countered with the view that BSUoS charges are calculated as an ex-post adjustment to energy prices for all users and include constraints which result from short term operational management of the transmission system, whilst TNUoS charges recover the long term costs of transmission investment. Others thought this would require careful consideration if extended to TNUoS, in that what is currently a fixed annual charge may begin to affect generation running decisions if it became a variable charge instead. There was some discussion on the potential for a commodity-based charge to impact on wholesale prices; however this would need to be evidenced via analytical modelling.

4.48 One member believed that a commodity (MWh) based charge would be a very effective outcome in supporting security of supply as generators would no longer be faced with a “stay open or shut” decision but with a “stay open and run or don’t run decision; i.e. this was a much softer signal on generation to close without imposing massive transmission liabilities in the process. There was no evidence brought forward to support this view and other members of the group disagreed, expressing a view that the reverse might be true given the potential impact on plant providing baseload power.

4.49 National Grid indicated that revenue recovery from transmission network users could, depending on which approach to postalisation was adopted, move from being a (MW) fixed monthly value (as under a capacity based charge) to a value that varies month-on-month due to generator usage patterns (under a commodity (MWh) based charge). Analysis undertaken subsequently, using 2011/12 revenues and actual metered demand data from 2009, illustrates a shift of £77m in revenue collection from summer to winter occurs as shown in Figure below.

Figure 2 - Revenue Recovery for Capacity vs. Commodity Charges



4.50 Discussion in the group also considered how an ex-ante charge might work, with agreement that there would need to be reconciliation and perhaps a factor applied to level out revenue recovery over the year.

4.51 Storage technologies (such as pumped storage, battery storage etc.) use the same transmission assets to both import and export energy. The current (Triad based) demand charging methodology leads to demand charges for storage being small as they are unlikely to consume energy over the peak. Storage is thus in practice only subject to generation TNUoS charges. Any move away from charging demand via a Triad approach would significantly undermine the economics of storage (with potential double charging for the same transmission assets) unless an alternate charging arrangement was put in place to explicitly remove storage from demand charges. This point was noted by the group.

4.52 The continued appropriateness of charging half hourly metered demand on the basis of the Triad when transmission investment costs were anticipated to being driven increasingly by year round conditions was noted as an issue, but was not considered by the Working Group.

4.53 Some Working Group members believed that, as the focus of postalised tariffs was on cost recovery rather than signalling the cost of transmission investment, this meant there was no strong rationale for choosing between

MW and MWh as a charging basis. Others felt that MWh charging better reflected a generator's usage of the transmission system, thereby targeting costs at those that make use of the system (in a similar way to BSUoS charging). One Working Group member thought that scaled MW would better reflect usage than MW, and might avoid issues raised around a MWh charge. In addition, some felt that charging for transmission on a MWh ex-post basis could improve generator cash-flow, which could be beneficial to new entry.

Working Group Conclusions and Position on Theme 1 – Improved ICRP

4.54 Agreement was reached regarding the proposal to use dual backgrounds in the Transport Model. Whilst it was noted that prior approval of the NETS SQSS proposal GSR009 would have been useful in reaching a consensus, it was generally accepted that the background scalings provided in Table 4-2 were reasonable to be used in an Improved ICRP model.

4.55 Whilst noting that there was little to choose between options for allocation of circuits to Transport Model backgrounds, the Working Group agreed to recommend use of the binary approach in the Improved ICRP model.

4.56 There was general agreement for the use of two separate wider locational tariff elements derived from the proposed peak security and year round backgrounds. It was felt that if the peak security tariff were applied to conventional generation only, then the appropriateness of the application of the year round tariff element to very low load factor generation should also be considered.

4.57 The group agreed that peak security tariffs should continue to be levied on a capacity (MW) basis. No consensus was reached regarding the levying of this tariff on intermittent generation.

4.58 No consensus was reached regarding on what basis to levy the year round tariff in an Improved ICRP model.

Working Group Conclusions and Position on Theme 1 – Postage Stamp

4.59 There was no agreement as to the treatment of demand under the Postage Stamp model.

4.60 No consensus was reached; between a commodity (MWh), and a scaled or unscaled capacity (MW) charge in relation to the chargeable unit to be used under the Postage Stamp model.

5 Summary of Theme 2 Working Group Discussion

5.1 This section summarises the Working Group discussions on Theme 2 - geographical / topological differentiation of costs. Broadly these discussions centred on two issues;

i) The boundary between local infrastructure and wider infrastructure;

ii) The method of cost differentiation across local and wider tariffs, which for wider infrastructure was deemed to only be of relevance to the Improved ICRP option.

5.2 Currently, for generation users, the locational element of the TNUoS tariff is comprised of three separate components. A wider component reflects the costs of the wider network, and the combination of a local substation and a local circuit component reflect the costs of the local network.

5.3 Local components were introduced into the TNUoS charging methodology in 2009[16] in order to provide a cost reflective signal for assets local to generation. This was to provide the appropriate charging signal to users in choosing between differing levels of transmission investment through the NETS SQSS connection design provisions such, that these decisions (by the user) are made which result in the most economic and efficient outcome.

5.4 It was noted that in many instances Users are given a connection with a design variation (single circuit connection) by the Transmission Owner as the only practical/economic connection option (i.e. not all Users have a choice over the design of their local assets).

5.5 All generation that is subject to TNUoS and not connected directly to a Main Interconnected Transmission System (MITS) substation will have a circuit component to their Local Charge. For charging purposes a MITS substation is defined as: (i) a Grid Supply Point (GSP) connection with 2 or more transmission circuits connecting at the substation; or (ii) more than 4 transmission circuits connecting at the substation.

5.6 Cost differentiation for wider infrastructure for generation users is currently managed via a zoning process whereby geographically and electrically proximate nodes are grouped together into zones providing their nodal costs are within +/-£1.00/kW. Other than in exceptional circumstances, zones are fixed for the duration of a transmission price control review.

5.7 Demand zones are fixed and relate to the GSP groups used for energy market settlement purposes.

Issues and defects this theme seeks to address

5.8 To assist the Working Group, Ofgem compiled a summary of the responses to their Project TransmiT Call for Evidence (September 2010) for the six themes under consideration. The responses given in Table 5-1 below relate to those responses relevant to Theme 2 – geographical / topological differentiation of costs.

What is Theme 2?

Theme 2 seeks to address the issues of topological and geographical differentiation of costs. These were interpreted by the Working Group as the boundary between local and wider infrastructure for charging purposes and the zoning criteria used in setting the wider locational tariff respectively.

[16] GB ECM-11 'For the charging arrangements for Generator Local Assets' Conclusions report; http://www.nationalgrid.com/NR/rdonlyres/27F920CA-C678-4D91-A3D1-701E909BDAFB/28281/GBECM11ConcReport_final_HR.pdf

Table 5-1: Summary of Call for Evidence Responses Relating to Theme 2

Respondent	Issue / defect
PX Limited, Orkney Islands Council, Piccsi, Renewable UK, SCDI, Scottish Government	The current charging model produces zonal locational differentials across GB. There are perceived issues with the scale of the zonal differential. These respondents noted a desire to reduce or smooth the scale in the disparity/variance of zonal TNUoS tariffs (eg modify zoning criteria), or remove geographical differentiation completely.
NGET, SCDI, Orkney Islands Council, OREF, Pelamis Wave Power, Renewable UK	The current TNUoS methodology does not consider the treatment of transmission links to island users.
Centrica, OREF, Pelamis wave power, Renewable UK, RWE, SSE, SCDI, Scottish Government	The current TNUoS methodology contains locational charging elements and socialised charging elements. It is appropriate to consider the current split between these elements and the treatment of local (user specific) infrastructure assets and the local/wider boundary in particular (ie extension of the principle of postalisation to all Local Infrastructure Assets or the maintenance of some sort of user specific signal).
Centrica, DONG, EDF Energy, NGET, HIE, Orkney Islands Council, Renewable UK, RWE, SCDI, Statkraft, Statoil	The current TNUoS charging methodology does not reflect the growth of an offshore transmission network. It is appropriate to examine the impact of OFTO revenues and the dominance of the local charge under the current charging mechanism.

5.9 The Working Group debated whether this list fully reflected all of the issues raised by respondees, in particular whether it captured the volatility and lack of predictability noted by some respondees.

5.10 There was a view that this was captured in Theme 2, in so far as some respondees considered that non-locational postage stamp charges would smooth out volatility and that changes to the zoning criteria for ICRP could have a similar effect. Others thought that volatility and predictability should be the basis of a seventh theme.

5.11 Ofgem noted that volatility and predictability would form part of the assessment criteria for each methodology put forward.

Options Discussed

5.12 Options were discussed for both Postage Stamp and Improved ICRP models, and are described below.

Improved ICRP Model

5.13 Considerations were focused on the two issues described in paragraph 5.1.

Local / wider boundary

5.14 The Working Group discussed whether there was a need to reconsider the definition and boundary between local and wider charges under an improved ICRP model.

5.15 Given the level of reinforcements planned over the next price control period, one Working Group member suggested that the definition of what constituted wider infrastructure could be based on planned rather than existing network assets. This member believed that this approach might help to stabilise charges and align with the forward looking focus of ICRP. No detail was put forward as to how this could work in practice.

5.16 Apart from the island issues, discussed in more detail below, the majority of the Working Group was content to retain the status quo definition.

5.17 The specific relevance of the local/wider boundary for offshore and island links, due to the relatively high cost of sub-sea transmission technologies, was discussed by the Working Group. Concern was raised by some Working Group members that as a result of the increasing proportion of transmission asset value taken up by offshore developments, which would primarily be local (and hence contribute to the 27% of revenue collected from generation users), that this would result, over time, in a lower residual element of tariffs for all generators.

5.18 Those who believed that this was an issue put forward a view that, despite locational differentials being maintained (as only the flat residual element is affected), this could be perceived as a cross-subsidy and a flaw with the existing ICRP methodology. Potential improvements were discussed by the Working Group including the transfer of some local assets to wider assets. It was also noted that this issue had a potential overlap with Theme 6 (G:D split -; refer to Section 9).

5.19 For islands, it was noted that planned reinforcements for two of the three Scottish islands being considered for the development of generation projects would lead to some island connections becoming part of the wider infrastructure for charging purposes. For the third island, a first planned HVDC link would be a local asset that would subsequently become wider if a second transmission circuit were installed.

5.20 Island charging is not currently codified, although it was the subject of a charging consultation[17] that proposed a similar treatment to offshore assets (i.e. the use of specific expansion and security factors) on the basis that these connections would be classed as local assets under the current definition.

5.21 It was noted that, under the current definition, if island connections were to become part of the wider transmission network (e.g. if a Grid Supply Point was built in addition to two transmission circuits under the current methodology) that this would likely lead to the creation of additional TNUoS zones due to the significant cost of sub-sea cable connections. This would result in similar locational differentials between the island and mainland connection points as the local circuit approach except that the tariff would no longer be multiplied by a specific local security factor (i.e. 1.0), but the generic global security factor (i.e. 1.8), thus significantly increasing tariffs.

[17] http://www.nationalgrid.com/NR/rdonlyres/5492DC2B-5A82-478A-8673-0EBAC44D2C69/39267/GBECM20Consultationv11.pdf

Some members suggested that Ofgem should liaise closely with DECC on island charging in the context of its Section 185 powers.

5.22 One Working Group member believed that there has been a working assumption that, where island connections would become part of the wider infrastructure for charging purposes, island connections would most likely nonetheless be charged as if they were local circuits. (i.e. would not be subject to the global security factor of 1.8 applied to all wider locational tariffs) .

5.23 This member's view was that it was never a realistic prospect that island circuits forming part of the wider infrastructure for charging purposes would be charged a tariff comprising the global security factor of 1.8. Others felt that the status quo model should reflect a straight extrapolation to the islands of what the CUSC currently defines as wider infrastructure, resulting in some island tariffs including the global security factor of 1.8.

5.24 Whilst there was no consensus on the treatment of island links forming part of the wider infrastructure for charging purposes in the status quo model, a proposed solution was put forward for Improved ICRP by the group and is discussed further in Section 6

5.25 Another discussion within the Working Group concerned whether the local charge accentuated locational signals. It was commented that the local and wider calculations were essentially the same, except for more specific inputs for local charges.

5.26 These specific inputs include:

- The use of actual circuit costs for offshore and island connections when calculating the expansion factor due to a lack of cost data for these technologies;
- A lower asset life assumption for offshore connections (aligned with the OFTO licence period);
- A specific security factor for each local connection. (rather than the global factor of 1.8 used for wider circuits).

5.27 As outlined in paragraph 5.3, local tariffs were introduced to provide an efficient signal when generation opt for a connection with a lower security standard (i.e. design variation from the NETS SQSS). One Working Group member noted that users benefited from the specific security factor, which has the effect of reducing tariffs for less secure connections.

Cost Differentiation of Local and Wider Infrastructure

5.28 The Working Group had different views on the locational signals arising out of the ICRP model. In order to set the scene one Working Group member set out their view on how the ICRP methodology produces differentials and where simplifications are used and some costs are consequently not included in the calculation of the locational differential (i.e. would be recovered through the flat residual element of tariffs)[18].

[18] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/Postalised%20model%20%20-%20HS%20GG%20slides%201.pdf

5.29 There was some discussion as to whether the current ICRP methodology gave a suitably cost-reflective locational signal. The Working Group discussed various enhancements to distance-related costs, with some feeling that ICRP does not produce sufficiently cost reflective locational signals whist others had a counter view, namely that the ICRP was currently over cost reflective.

5.30 The Working Group debated both increasing and dampening of the geographical differentiation of costs.

5.31 Differentials in the wider tariff are averaged into zones. The zoning criteria for wider locational charges, set out in paragraph 5.4 above, assign nodal marginal kilometres (i.e. costs) to zones in a way that seeks to manage "the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity"[19]. In the existing methodology this requirement is balanced with the requirement for cost-reflectivity through the maximum £2/kW spread in nodal tariffs comprising a single zone. Currently this has led to 20 generation TNUoS zones in GB.

5.32 At both the Glasgow stakeholder event on the 30 June 2011[20] and the WG1 meeting[21] National Grid noted that the generation zoning criteria represent this balance between stability and cost-reflectivity and that a change to these criteria could change this balance if it was found to be incorrect.

5.33 One member proposed that the Working Group should consider the option to put all transmission in the Transport Model as 400kV overhead line. The member's logic presented in support this approach was as follows:

i) If there were no planning issues, the entire onshore transmission network would be built as overhead lines without cables. New forms of low carbon generation connecting to the network face more cable (underground) connections because the public increasingly demands this;
ii) New underground/undersea technologies (e.g. HVDC) are not as expensive or intrusive as 400kV underground AC cables;
iii) Low carbon generators have fewer options to relocate to avoid such connections;
iv) The proposal aligns with the EU Directive on peripheral regions as peripheral regions tend to be connected at lower voltages and therefore face higher charges under the current method. This proposal would satisfy the Directive;
v) The proposal is a simple cost reflective model which will be more stable and transparent;

5.34 Another Working Group member put forward alternative suggestions for dampening some locational elements of the ICRP methodology, specifically:

- Model wider tariffs with a security factor of 1 on the basis that security is a global benefit and users have little or not choice in this.
- Explore alternative zoning criteria which would average costs over a wider area.

5.35 The Working Group member provided some indicative wider tariffs for the 400kV overhead line treatment (outlined in paragraph 5.33) as well as the security factor of 1 and alternative zoning criteria. (outlined in paragraph 5.34). These are reproduced in Annex 8.

[19] CUSC Section 14 - The Statement of Use of System Charging Methodology, paragraph 2.21
[20] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/NGET%20presentation.pdf
[21] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/Web%20Forum_NGridPPSlide.pdf

5.36 The majority of the Working Group felt that insufficient justification was put forward for the aforementioned approaches to dampening the locational differential signal for them to be taken forward as part of the improved ICRP model

5.37 One Working Group member put forward a paper on a proposed treatment of new technologies (e.g. series capacitors and quadrature boosters) that improve boundary flows, proposing that they be included in the distance-related costs (some of which are discussed in Section 7 of this report). This was discounted from inclusion in the Improved ICRP model.

5.38 The same Working Group member also promoted a methodology adopted in Ireland which restricts the locational differentials to be based on those circuits that are planned to be reinforced or newly constructed in the next few years or have recently been reinforced or newly constructed. The methodology is described in SEM 11-037 of June 2011[22].

5.39 This Working Group member supported the principle of investigating the basic methodology of determining locational differentials as described, but not necessarily the exact implementation as proposed, for Ireland. The chair indicated that this topic was out of scope for discussion by the Working Group as the methodology was neither Status Quo, Improved ICRP nor Postage Stamp.

5.40 One Working Group member presented data (included in Annex 7) from National Grid's TEC register[23] in support of the view that the Status Quo ICRP methodology had a limited effect on the locational siting of generation. Members noted that this was outside the remit of the Working Group.

5.41 The potential for capping and collaring of the highest and lowest locational tariffs in order to provide stability and predictability for long-term generation investments and to support renewable projects on the periphery of the transmission network was suggested by one Working Group member. No proposal was brought forward for how this would be implemented and one member believed that fixing some transmission tariffs would make others more volatile. Some members also believed that transmission network charges may not be the most efficient vehicle for the promotion of renewable generation as this was the purpose of the Renewable Obligation and the proposed CFD FIT mechanism. No Working Group consensus was reached on this.

5.42 The consensus of the Working Group was one of general support for the current generation charges zoning methodology.

Postage Stamp Model

5.43 The Working Group agreed that the application of theme 2 to the postalised model also related to both issues of the local/wider boundary and the cost differentiation of wider infrastructure.

Local / wider boundary

[22] http://www.allislandproject.org/en/transmission_current_consultations.aspx?article=c513b4c4-5062-4b3f-a579-edb8d763ce4a&mode=author

[23] http://www.nationalgrid.com/NR/rdonlyres/AA41B933-3CE1-453B-8AE6-CAF387768837/48984/TEC12September11.xls

5.44 The Working Group discussed the need and level of distinction between local and wider infrastructure asset charging.

5.45 The group noted that there where three key broad choices that could be considered:-

i) Removing the 'local' charging boundary and applying a uniform tariff to all infrastructure assets (local and wider combined ~ £465m of transmission revenue for 2011/12)

ii) Retaining the local/wider boundary (no change, as now ~ £113m local and £352m wider transmission revenue for 2011/12)

iii) Retaining the boundary but with modifications. One suggested alternative was to recognise that some 'local' assets are likely to transition to 'wider' in the long run, as outlined in paragraph 5.15 (e.g. anticipatory change to wider as a result of demand on the islands).

5.46 There was considerable debate within the group over the exact nature of postage stamp model for charging. There was consensus that such a model does not, in principle, differentiate costs by distance.

5.47 Consideration was given as to whether a uniform tariff should be applied throughout, option (i) in paragraph 5.45, as some of the Working Group believed that this would be more consistent with a principle of removing all locational differentiation of costs by distance.

5.48 One justification for this view was a belief that a charging model that sought to retain some elements of cost-reflectivity and socialise the remainder could lead to perverse incentives at the boundary between the two. The potential result is that more transmission assets could be built (under this option) above what is considered to be an efficient level at greater cost to the end consumer. One member noted that the Transmission Owners would only be allowed by Ofgem to include the costs of an economic design in their Regulated Asset Base.

5.49 A member of the working group also felt that as the rationale for introducing the concept of a local charge was to improve on the cost reflectivity of charging for local assets, where for instance lower levels of security exist than implied by a 1.8 security factor, there didn't seem to be the same requirement to retain one under a socialised approach. Otherwise, there could be a perception of cost reflectivity being selectively applied in order to benefit particular parties (i.e. those with low levels of local assets).

5.50 Some members believed there were disadvantages to the removal of the cost-reflective local charge, i.e. they favoured option (ii) in paragraph 5.45. They believed that, contrary to the concerns noted in paragraph 5.48, the removal of an incentive from users to make efficient choices in local transmission connection designs would increase total costs to end users associated with local assets. It was also considered inappropriate to socialise costs that are clearly driven by specific generator choices (where these are not made by the Transmission Owner) due to local assets. One member noted the potential negative impact on island connections with local circuit tariffs if a cost-reflective local charge remained.

5.51 It was also suggested that a boundary could be maintained, but with modifications such as recognising that some local assets may become wider over time, option (iii) in paragraph 5.45. This could potentially remove some of the perceived shortcomings of the current definition (e.g. the appearance of demand can move an island connection from local to wider).

Cost Differentiation of Wider Infrastructure

5.52 The Working Group considered the issue of whether the postalised charge should have any cost differentiation applied to wider transmission infrastructure assets. Two options were discussed by the group and are summarised in Table 5-2, below.

Table 5-2: Options for Postage Stamp Cost Differentiation

Generation	Demand
Uniform tariff for use of wider network	Retain locational differentiation on demand, using the existing ICRP methodology. Maintain Triad and the £/kW and p/kWh rates for HH and NHH demand respectively charging.
Uniform tariff for use of wider network.	Uniform tariff for use of the wider network. Maintain Triad and the £/kW and p/kWh rates for HH and NHH demand respectively charging.

5.53 Concern was raised over the option to remove the locational signal from generator transmission charging whilst leaving it in place for demand charging. Some felt that this could be viewed as discriminatory and that there was no evidence put forward to suggest that demand users are more reactive to locational signals than generators. Others believed that the existing misalignment of demand charging zones meant that there was sufficient precedent of a different treatment for demand.

5.54 The differences between the two relate to the difference in treatment of demand users. The majority of working group members believed that both generation and demand users should be treated the same and exposed to a postalised charge (ie both exposed to a uniform charge). A minority of the group believed that only generation users should be exposed to a postalised charge and that demand users should continue to pay charges based on the existing ICRP methodology.

Working Group Conclusions and Position on Theme 2 – Improved ICRP

5.55 A general consensus was reached that there was no strong reason to change the current generation charges zoning criteria within the Improved ICRP model.

5.56 A majority were in agreement that there was no strong reason to change the current local / wider boundary within the Improved ICRP model.

Working Group Conclusions and Position on Theme 2 – Postage Stamp

5.57 Several Postage Stamp models were presented to the group and these are captured in Annex 5 – Detailed Options for Postage Stamp Models

5.58 There was no agreement on whether the existing local / wider boundary would remain in place in a Postage Stamp model.

5.59 There was agreement amongst the group that a postage stamp model is one that doesn't differentiate costs by distance for generators. A minority believed that it may still be appropriate to do so for demand.

6 Summary of Theme 3 Working Group Discussion

6.1 This section summarises the Working Group discussions relating to Theme 3 – treatment of security provision. The Working Group noted that this was specifically an issue related to the improved ICRP model as it was noted that this theme was much less relevant in a postage stamp approach to transmission charging.

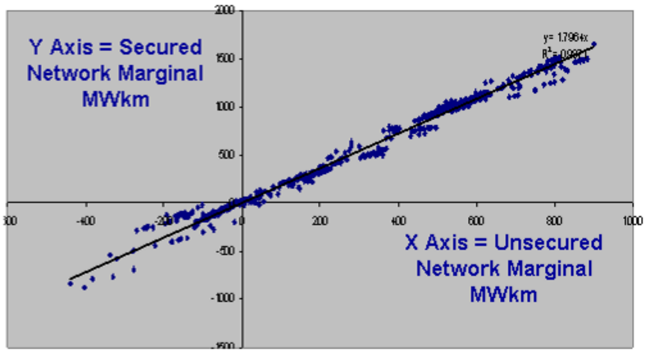
6.2 Currently, the locational onshore security factor for the wider transmission network is derived by running a secure DCLF ICRP transport study based on the same market background as used in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak demand can be met despite the Security and Quality of Supply Standard (NETS SQSS) contingencies (simulating single and double circuit faults) on the network.

6.3 The calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

6.4 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method.

6.5 The prevailing security factor for the wider network is 1.8 and is based on an average from a number of studies conducted by NGET to account for future network developments. The security factor is reviewed for each transmission price control period and fixed for the duration.

Figure 3 - Illustration of Least Squares Fit Approach for Global Security Factor



Issues and defects this theme seeks to address

6.6 To assist the Working Group, Ofgem compiled responses to their Project TransmiT Call for Evidence in September 2010 to the six themes under consideration. The responses given in the table below relate to those responses relevant to Theme 3:

What is Theme 3?

Theme 3 seeks to address how the charging methodology deals with the redundancy (i.e. N – 1 or N – 2 security) built into the local and wider elements of the transmission network in accordance with the NETS SQSS. Treatment of island links becoming part of the wider network is also considered.

Table 6-1: Summary of Call for Evidence Responses Relating to Theme 3

Respondent	Issue / defect
International Power, NGET, Tim Russell	The ICRP model does not explicitly recognise the existence of spare capacity and/or the level of redundancy (or lack of). The actual 'security factor' will vary from place to place on the network and will depend on demand and generation dispatch. It is appropriate to consider arrangements that better reflect regional or individual security.

Options Discussed

6.7 National Grid introduced the concept of the security factor and the potential options for change. Specifically, the possibility of introducing a locationally varying, as opposed to global, security factor was presented as an option for change. However, National Grid also noted that any change would alter the balance between cost-reflectivity and the stability and predictability of tariffs.

Locational Security Factors

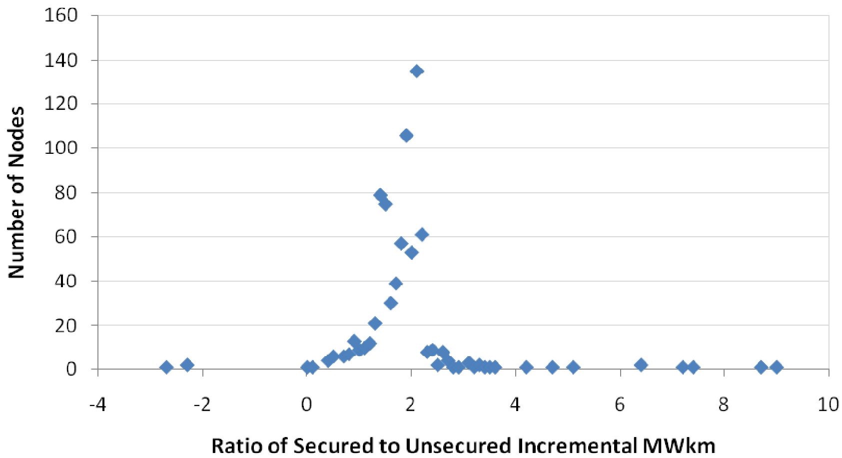
6.8 The Working Group noted the stability and predictability of the current arrangement as being a highly desirable feature.

6.9 Some members of the Working Group requested additional information on the nodal variance from the global security factor and sought clarification as to whether there were any geographical patterns in the variance.

6.10 National Grid clarified that the secured load flow methodology used to calculate the global security factor excluded local circuits (many of which have a security factor of 1.0), and that the methodology compared secured incremental MWkm with unsecured incremental MWkm. The majority of the Working Group requested further information on the detail of the methodology.

6.11 National Grid circulated a presentation on the operation of the secured load flow, which included an example calculation, to the group and also agreed to provide information showing the distribution of nodes around the mean security factor. This is shown in Figure 4, below.

Figure 4 - Distribution of Nodal Security Factors



6.12 The Working Group was presented with this information graphically and noted that there was no geographical pattern to nodes outside of one standard deviation from the mean. These nodes were shown to be spread across generation TNUoS zones 11 and 14.

6.13 Upon being presented with the above distribution, the Working Group generally agreed that there was sufficiently convincing evidence for continuing with the current methodology for the treatment of security provision and its application to both the local and wider transmission system.

6.14 One member of the group suggested that the data on the distribution of nodes around the mean be presented in a different format to better illustrate the zones in which those nodes which deviated most significantly below or above the mean were located. Others noted that on the basis that the secured load flow model is flow related, takes into account all credible contingencies and excludes circuits classified as local, the parts of the network that the member is interested in are adequately captured by the analysis provided.

6.15 One member noted that variable renewable generators would normally connect to a network with a single circuit and would not voluntarily pay extra for added security of N -2 redundancy. (i.e. they would accept a security factor of 1 locally). Extending this principle to the wider network this member believed that it was not reasonable to base charges for such generation on the higher security factor (i.e.1.8) sought, in their view. by demand users in particular. However, most members of the WG thought that as the renewable projects were benefitting from the wider 1.8 security factor and associated firm access rights to the wider network, they therefore should pay for it.

6.16 The Working Group noted the general consensus that the current treatment of security provision was appropriate and should be modelled by Redpoint in its current form.

Island Security Factors

6.17 Ofgem noted that the key outstanding issue in Theme 3 was the security treatment of potential transmission links to island groups within the TNUoS methodology.

6.18 As noted in Section 5, the growth of demand on the islands may lead to the construction of a grid supply point. As a result a situation could arise where island connections would shift from being a local circuit to being considered part of the wider transmission network under the existing charging methodology, due to the application of the local/wider boundary criteria as outlined in paragraph 5.4.

6.19 In the aforementioned situation this would result in the GB global security factor (currently 1.8) being used in the calculation of a generator's TNUoS tariff as opposed to a local security factor of 1.0 (reflecting the likely situation that the loss of a single circuit would result in complete loss of access to the network).

6.20 The Working Group was asked to consider whether there was justification to treat island links as a distinct group within the calculation of the GB global security factor and Ofgem noted that the modelling approach will need to make a decision on this issue.

6.21 The options initially noted by the Working Group were:

i) Assume that, consistent with the current methodology, potential island links will transfer to the wider network where applicable and the global security factor (1.8) would be applied from this point,

ii) Treat islands as a "special case" on the onshore wider network and allow charges to continue to be set on the basis of a security factor less than 1.8, or

iii) Alter the definition of the local/wider boundary (see Section 5) in order to preclude islands from becoming part of the wider network.

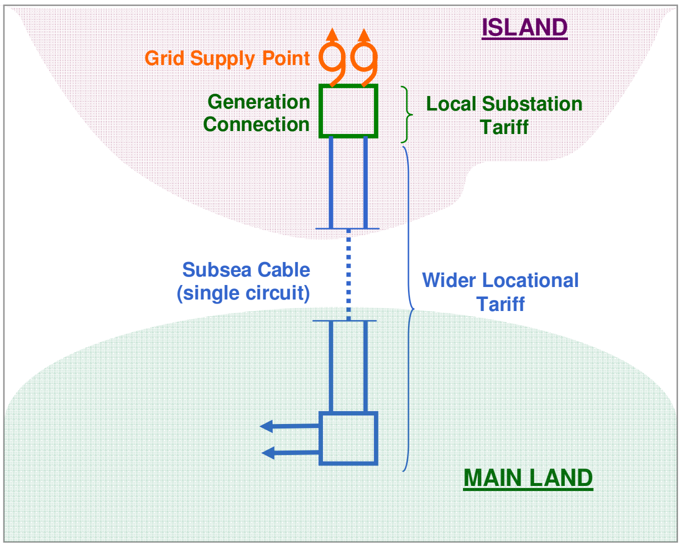
6.22 Some members of the group noted concerns regarding option (ii) for the reason that special treatment for islands generators in this instance could potentially set a precedent for concessions in other areas.

6.23 Following some debate, the Working Group were of the broad opinion that the modelling should seek to apply the GB global security factor (1.8) to circuits considered to be part of the wider transmission network.

6.24 Some members confirmed their understanding that island links designed with little or no redundancy (i.e. not compliant with NETS SQSS) would not have firm access to the wider transmission network. As such, generators connected on the island would not receive compensation for loss of transmission access due to unavailability of the single circuit. However, the quid pro quo is a reduced TNUoS charge by way of a specific security factor as part of the local circuit charge.

6.25 The Working Group noted that, should option (i) be modelled, the principle of the TNUoS tariff remaining commensurate with the firmness of transmission access rights, as delivered through the local circuit charge, was sound and that further changes were therefore likely to be warranted. The situation depicted in Figure 5, below, was discussed by the group.

Figure 5 - Island Connections as Part of the Wider Network



6.26 The Working Group debated the implications of the agreed approach and discussed a range of alternative options, these included:

i) Island generators paying a wider locational tariff derived from the application of the global security factor (1.8) and receiving compensation if the single circuit sub-sea cable link was unavailable; or

ii) Island generators paying a wider locational tariff derived from the application of the actual level of resilience, which could mean the global security factor (1.8) would be used for all but the single circuit sub-sea cable link that would have a specific factor of 1.0. In this situation the generator would not receive any compensation for the unavailability of the single circuit link.

6.27 It was noted that the methodology could reflect the level of redundancy associated with a single circuit cable link in the zonal tariff calculation by modifying the specific expansion factor applicable to the sub-sea cable section of the island connection. This would be done by dividing the expansion factor by the prevailing global security factor (currently 1.8). Ultimately, through the application of the global security factor to the overall zonal locational tariff calculation, this would result in a zonal tariff reflective of the specific security characteristics of the single sub-sea cable link included in this part of the wider transmission network.

6.28 The Working Group noted the importance of being mindful of setting unintended precedents when developing the policy for dealing with a nested lack of redundancy on a radial piece of the transmission network. Any principles developed should fall within universal principles that will be enduring. Therefore, the drafting of the methodology text for such an approach would have to be carefully considered to ensure that the arrangements would not apply unintentionally to other local circuit links where it would not be appropriate to do so.

Working Group Conclusions and Position on Theme 3

6.29 There was a majority view that the existing approach to calculating a GB wide global security factor (currently 1.8) remained an acceptable approach to the treatment of security provision.

6.30 The majority of the Working Group agreed that island links should not receive special treatment through the selection of a specific security factor, once they become part of the wider transmission network (where applicable). However, it was agreed that where the generators see a TNUoS tariff which reflects a secure transmission system it was understood that such parties should also receive compensation associated with firm transmission rights.

6.31 The Working Group did agree that it would be appropriate to reflect the reduced security that generators on a wider radial spur with a section of single circuit would receive. This would be affected through a change in the expansion factor calculation (i.e. divided by 1.8). However, it was noted that compensation for loss of transmission access would not be available under these circumstances for the loss of the single circuit section.

6.32 There was a consensus that the above approach outlined in 6.30 be incorporated into the modelling of Improved ICRP.

7 Summary of Theme 4 Working Group Discussion

7.1 This section summarises the Working Group discussions relating to Theme 4 – reflecting new transmission technology and specifically those relating to options that could be developed for an improved ICRP model as it was noted that this theme was much less relevant in a postage stamp approach to charging.

7.2 Currently the element of the TNUoS charging model that calculates nodal incremental costs does this using a set of input data including nodal generation and demand, transmission circuits and their characteristics (length, impedance, voltage and whether cable or overhead line). This is called the Transport Model.

7.3 The Transport Model then uses the DCLF ICRP transport algorithm to derive a resultant pattern of power flows based on the network impedance for both a 'base case' and 'incremental MW' scenario. This is used to calculate the incremental network MWkm for 1 MW of generation and demand (equal and opposite to generation) for a given node on the network.

7.4 The Transport Model employs the use of circuit length expansion factors to reflect the difference in cost between:

i) AC cable and overhead line routes

ii) 132kV, 275kV and 400kV AC circuits

7.5 As the transport model expresses cost as marginal kilometres (irrespective of technology) and uses 400kV overhead line as the base technology, some account needs to be taken of the fact that investment in other technologies is more expensive. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect additional cost.

7.6 The Transport Model does not take into account the cost of other technologies used to increase the capability of the transmission network. In April of 2006 National Grid undertook a review of the elements included in the incremental cost of capacity as part of GB Charging Condition 2[24]. This review considered the addition of quadrature boosters (QBs) and reactive compensation devices into the calculation of locational differentials.

7.7 At that time National Grid concluded that, due to the way in which they redirect power flow on the transmission system, rather than provide additional capacity, the addition of QBs was likely to be subjective. Condition 2 proposed that the potential increased cost reflectivity of inclusion of QBs in the Transport Model was outweighed by the increased subjectivity and complexity that this would introduce.

7.8 A similar consideration was given to reactive compensation devices (SVCs, RSVCs, MSCs and Reactors). At that time, Condition 2 considered that a more complex model and charging base would need to be developed to incorporate reactive power and that the benefits would be outweighed by a reduction in transparency and simplicity of the model.

7.9 In order to accommodate increasing volumes of new generation connecting to the transmission network, the Transmission Owners have proposed the use of High Voltage Direct Current (HVDC) links[25] that parallel the AC network and would be routed offshore in order to avoid planning and

What is Theme 4?

Theme 4 seeks to address how the charging methodology deals with new technologies, not currently taken into account in the Transport and Tariff Model when calculating locational differentials. The main focus in this area is on HVDC links that parallel the onshore AC transmission network.

24 http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/2/

25 One example can be found at: www.westernhvdclink.co.uk

consenting constraints (and associated timescales) onshore. HVDC links are not currently catered for in the Transport Model.

Issues and defects this theme seeks to address

7.10 To assist the Working Group, Ofgem compiled responses to their Project TransmiT Call for Evidence in September 2010 to the six themes under consideration. The responses given in the table below relate to those responses relevant to theme 4:

Table 7-1: Summary of Call for Evidence Responses Relating to Theme 4

Respondent	Issue / defect
DONG, Eon, ESB International, NGET, Renewable UK, RWE, SCDI	The current TNUoS methodology does not recognise the treatment of HVDC links (or network technology change in general).

Options Discussed

7.11 At both the Glasgow stakeholder event on the 30 June 2011[26] and the WG1 meeting[27] National Grid presented their view that the determination of a methodology for the inclusion of HVDC was an important element that should be addressed within the remit of the Significant Code Review.

7.12 These presentations indicated that the two main issues to be addressed in order to facilitate HVDC circuits in the charging model were:

i) treatment of flows in the DC load flow element of the charging model, in light of the inherent controllability of power flows through an HVDC link;

ii) calculation of the expansion factor (i.e. relative unit cost) for HVDC circuits.

7.13 One member expressed a view that, whilst the major issue is how to adapt the charging technology to cope with HVDC links running in parallel with the main AC system, other pieces of technology were also worth reviewing. This member noted that some of this technology had been in use for some time, but was not currently modelled.

7.14 After some debate, there was a general consensus that the inclusion of HVDC links into the transmission charging methodology should be the main focus of the group.

7.15 The aforementioned Working Group member provided an overview of the technologies, other than HVDC, that may be considered for inclusion in the methodology.

7.16 **Series Capacitors –** These have not yet been used on the GB system but are planned to be used so come firmly under the category of new transmission technology. They add additional boundary capability to the transmission network by relieving voltage and stability constraints, which would otherwise restrict usage of a thermal capacity. Consequently the Working Group member believed that their cost should be included in the ICRP calculation by adjusting the expansion factor of the relevant circuit to reflect the installed cost of the assets (i.e. increase the cost of the circuit route in which the capacitor is installed).

[26] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/NGET%20presentation.pdf
[27] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/Web%20Forum_NGridPPSlide.pdf

7.17 **Quadrature Boosters (QB) –** These have been in use in GB for some time and the Working Group member suggested that they could be treated in a similar manner to that proposed for series capacitors. However, by increasing or decreasing the flow of power in their circuit in order to optimise the power flow distribution in a number of transmission circuits, the Working Group member suggested that there is an argument that the cost of the QB should not be attributed to the circuit that it is inserted into but to all the circuits across a transmission boundary, the sharing of flows across which it optimises.

7.18 **Shunt devices that increase transmission boundary flow capacity –** Typical devices in this category would include SVCs and shunt capacitors. The cost of these devices is not currently included in the ICRP calculation although as they can increase boundary flow capabilities and have an associated cost the member believed it could be argued that they should be. The proposed approach was to treat shunt devices in a similar manner to QB's, above.

7.19 The Working Group noted the contribution of the member who provided the above approaches for incorporating other technologies into the transmission charging model and agreed that these technologies, covered in paragraphs 7.16 through 7.18, would not be taken further through this process.

7.20 Whilst agreeing with a focus on HVDC, the Working Group noted that the proposed HVDC links are unlikely to come online before 2015 and perhaps did not need to be addressed in the short term. However, due to their potentially significant impact on tariffs in an ICRP approach and the timeframes over which Redpoint are modelling (i.e. out to 2030), it was agreed that the Working Group should discuss options for the treatment of this new technology within the modelling scenarios.

7.21 National Grid delivered a presentation to WG3[28] detailing a range of options and illustrating the associated impacts for the treatment of new HVDC transmission technology. Specifically these options dealt with the cost treatment, i.e. calculation of the expansion factor, and treatment of HVDC with regards to the flow of the incremental MW in the DCLF calculation. The details of this work are outlined within Annex 4.

Treatment of HVDC in DC Load Flow

7.22 The Working Group agreed that the treatment of power flow down the HVDC link in the Transport Model would have to be based on a simplifying assumption due to the controllable nature of these links relative to power flows on the AC network, which are dictated solely by the impedance of a circuit that is fixed.

7.23 As a result the group agreed that, for an ICRP approach, National Grid's proposal to model HVDC links that parallel the onshore AC network as an AC circuit in the model would be reasonable simplification. This approach requires the calculation of an impedance for the transmission circuit (i.e. the circuit characteristic that dictates power flow).

7.24 One member developed a detailed paper outlining available options for incorporating HVDC into the charging methodology, with some input from National Grid. This paper, included in Annex 4, put forward five approaches to calculating an impedance for the HVDC link in the Transport Model. Options 2 through 4 focus on calculating a base case flow down the link, which would then be used to calculate the impedance.

[28] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/TransmiT%20WG%203%20-%20treatment%20of%20HVDC.pdf

1) optimum power flow,
2) base case flows in proportion to number of routes on a boundary,
3) base case flows in proportion to number of circuits on a boundary,
4) (a) base case flows in proportion to circuit ratings of a boundary,
   (b) base case flows in proportion to circuit ratings averaged across multiple boundaries.

7.25 National Grid undertook some analysis of the impact of each option on TNUoS tariffs and presented these results, along with some detail behind how the power flow calculation would be undertaken[29] at WG5.

7.26 The Working Group was in general agreement that option 4 was credible and presented a logical way of dealing with the calculation of impedance for the purposes of the HVDC Loadflow. It was agreed that option 4(b), taking into account multiple transmission boundaries would be put forward to Redpoint to model. Some members believed that this was the most theoretically correct model.

Expansion Factor Calculation for HVDC

7.27 At WG1, National Grid presented options for the treatment of HVDC costs when calculating the expansion factor in order to instigate work group discussion:

i) All costs of the technology included in the calculation
ii) Convertor station costs excluded on the basis that they provide additional flexibility in system operation, akin to reactive compensation and QBs
iii) Treat HVDC as 400kV overhead line on the basis that HVDC is only built because no suitable onshore AC alternative is available

7.28 Some members of the Working Group proposed that converter station costs should be excluded from the expansion factor calculation - option (ii). Conversely, some WG members preferred to include all HVDC costs, including those of the converter station, in the locational signal – option (i). Ofgem noted the precedent of offshore arrangements whereby converter station costs are included in the calculation of the locational signal.

7.29 As noted above in paragraph 5.33 above, one member proposed that the Working Group should consider the option to put all transmission in the Transport Model as 400kV overhead line; an extension of option (iii), above, to include the whole transmission network.. The Working Group did not believe there was sufficient justification to pursue this option further.

7.30 Some members raised the possibility that the modelling parameters for input into Redpoint's modelling of HVDC may be different in the Status Quo option than the Improved ICRP option.

7.31 Following some debate, the Working Group initially proposed that for the Improved ICRP model converter station costs should be excluded from the expansion factor calculation. A lengthy debate on the approach for the Status Quo model followed, with some Working Group members preferring to include all HVDC costs, including converter station costs, in the locational signal.

7.32 The Working Group noted that one of the difficulties with Theme 4 was that HVDC links paralleling the onshore AC transmission network were not due to come online until 2015, therefore clearly establishing the 'baseline' (i.e. 'status quo') was problematic. Consequently, one of the decisions to be

[29] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/NGET%20-%20Theme%204%20HVDC%20Final%20Option%20Assessment%20presentation.pdf

made was whether to treat HVDC the same for both the current ICRP methodology and the Improved ICRP, or to devise alternative arrangements for each scenario.

7.33 Some in the Working Group noted that while the precedent for offshore was to include converter station costs in the expansion constant, HVDC ‘bootstraps’ were inherently different (i.e. they will operate in parallel with the onshore transmission network whereas offshore links will be radial) and thus there were grounds for treating them differently.

7.34 However, some members of the group felt that there was an argument for a consistent approach to be adopted for radial links too such as when HVDC assets form part of an offshore generator’s local assets. In this instance, the local circuit charge would not include the cost of converter stations, but the local substation charge would include the cost of the offshore converter station. The cost of the converter station at the other end of the link would be recovered through the residual tariff. These members believed that this would be consistent with the present treatment of costs for similar transmission assets such as transformers.

7.35 One member noted that an approach to take converter station costs out of the locational calculation should be applicable to both onshore converter stations and those applicable to offshore links.

7.36 Some Working Group members noted their preference for a consistent approach for both Status Quo and Improved ICRP which they deemed necessary if the treatment of HVDC was not to contribute to significant differences in modelled outputs and obscure other effects.

Working Group Conclusions and Position on Theme 4

7.37 There was general consensus that new technology changes would only be made for HVDC links that parallel the onshore (AC) transmission network.

7.38 The Working Group agreed that the most appropriate approach to modelling the power flow down the HVDC link (i.e. calculating the impedance for the DC load flow model) was to use Option 4(b) – calculating base case flows in proportion to circuit ratings on multiple transmission boundaries.

7.39 The Working Group was unable to arrive at a consensus on the treatment of HVDC costs in calculating the expansion factor to be used in the Repoint’s modelling work. The 2 broad options identified by the group were:

- Option 1: Include all costs (i.e. converter stations and subsea cable) of HVDC links in the expansion factor calculation for both links that parallel the onshore transmission network and those used for offshore transmission. It was noted that this is consistent with the current precedent of offshore converter cost treatment - paragraph 4.30 of National Grid’s conclusions report for Charging Modification ECM-24.

- Option 2: Different cost treatment based on consideration of whether the link will parallel the (AC) onshore transmission network or not. Proposed approach is to exclude the costs of converter stations of the ‘bootstrap’ links that run parallel to the onshore network from the expansion factor calculation (i.e. recover that cost through the residual element of TNUoS). The costs of converter stations associated with offshore radial HVDC links - that do not parallel the onshore network - would be included in the expansion factor calculation.

8.1 This section summarises the Working Group discussions relating to Theme 5 – unit cost of transmission and specifically those relating to an improved ICRP model as it was noted that this theme was much less relevant in a postage stamp approach to charging.

Introduction

8.2 In order to calculate nodal marginal costs from the incremental MWkm arising out of the charging model as outlined briefly in paragraphs 7.2 through 7.5, a unit cost of transmission (i.e.£/MWkm) is required.

8.3 The current approach used in the ICRP methodology is to use an '*expansion constant*'. The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future transmission system expansion.

8.4 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible.

8.5 The table below shows the first stage in calculating the expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

Table 8-1: Illustrative 400kV OHL expansion constant calculation

MW	Type	£(000)/km	Circuit km*	£/MWkm	Weight
A	B	C	D	E = C/A	F=E*D
6500	La	700	500	107.69	53846
6500	Lb	780	0	120.00	0
3500	La/b	600	200	171.43	34286
3600	Lc	400	300	111.11	33333
4000	Lc/a	450	1100	112.50	123750
5000	Ld	500	300	100.00	30000
5400	Ld/a	550	100	101.85	10185
Sum:			2500 (G)		285400 (H)
				Weighted Average (J = H/G):	**114.160 (J)**

8.6 The weighted average £/MWkm ('J' in Table 8-1) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

What is Theme 5?

Theme 5 seeks to address how the charging methodology calculates the unit cost of transmission, called the expansion constant, used in setting the locational differentials of the TNUoS tariff.

8.7 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of each Transmission Price Control Review period and remain constant throughout that price control period. The WACC used in the calculation of the annuity factor is the National Grid regulated rate of return; this assumes that it will be reasonably representative of all licensees. The transmission asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

8.8 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

8.9 Using the previous example in Table 8-1, the final steps in establishing the expansion constant are demonstrated below:

	Ave £/MWkm
Weighted Average Overhead	114.160
Annuitised	7.535
Overhead	2.055
Final	**9.589**

8.10 This process of calculating the incremental cost of transmission capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control period and is increased by inflation, RPI, (May–October average increase, as defined in National Grid's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 11.143

8.11 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of transmission circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. These factors are fixed for each respective price control period.

Issues and defects this Theme seeks to address

8.12 To assist the Working Group, Ofgem compiled responses to their Project TransmiT Call for Evidence in September 2010 to the six themes under consideration. The responses given in the table below relate to those responses relevant to Theme 5:

Table 8-2: Summary of Call for Evidence Responses Relating to Theme 5

Respondent	Issue / defect
HIE, RWE, Voith, Tim Russell, Renewable UK	There are issues with the manner in which the TNUoS methodology models the cost of expanding the network and providing capacity. There is a need to review the main unit costs of providing capacity under the current TNUoS methodology to ensure it is reflective of accurate unit costs.

8.13 At both the Glasgow stakeholder event on the 30 June 2011[30] and the WG1 meeting[31] National Grid introduced the issue of the unit cost of transmission capacity and its relevance with respect to transmission charging. The divergence of the unit costs used in charging from actual unit costs for onshore transmission infrastructure was highlighted. It was explained that this divergence originated from two elements of the methodology:

i) the use of a basket of circuit types, weighted by recent historical usage on the transmission network, and the lack of up to date cost information for circuit types that are no longer procured;

ii) the use of RPI over a price control review period can diverge from the inflation of specific commodities used for transmission (as outlined in paragraph 8.4).

Options Discussed

8.14 The majority of the Working Group quite quickly came to the view that the unit cost of transmission capacity could be considered under the RIIO Transmission Price Control Review rather than fully debated within the Working Group.

8.15 Some members noted that while this was sensible, it was nonetheless important that the Working Group discuss it while they had the opportunity.

8.16 One Working Group member noted his view that the exclusion of non-distance related transmission assets meant that the method of calculating the expansion constant was sub-optimal.

8.17 Another member noted that any upward revision of the cost data used to underpin the expansion constant will have a significant impact in the northern regions (i.e. those with positive TNUoS charges) of the transmission system. As the expansion constant essentially sets the locational differentials in TNUoS tariffs, this was confirmed.

Working Group Conclusions and Position on Theme 5

8.18 There was a general consensus that, subject to noting the concerns expressed, consideration of the unit cost of transmission capacity should be deferred to the ongoing RIIO Transmission Price Control Review Process.

30 http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/NGET%20presentation.pdf

31 http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/Web%20Forum_NGridPPSlide.pdf

9 Summary of Theme 6 Working Group Discussion

9.1 This section summarises the Working Group discussions relating to Theme 6 – reviewing the generation / demand split.

9.2 The Status quo, Improved ICRP and Postage Stamp models are all covered under this Theme 6.

9.3 Currently, a TNUoS revenue split between generation and demand of 27% and 73% respectively is applied. This is referred to as the G:D split.

Issues and defects this theme seeks to address

9.4 To assist the Working Group, Ofgem compiled responses to their Project TransmiT Call for Evidence in September 2010 to the six themes under consideration. The responses given in the table below relate to those responses relevant to Theme 6

Table 9-1: Summary of Call for Evidence Responses Relating to Theme 6

Respondent	Issue / defect
AEP, Consumer Focus, Drax, EDF Energy, International Power, Mainstream Renewable Power, NGET, OREF, Orkney Islands Council, REA, Renewable UK, SCDI, Scottish Government, Scottish Power	The current TNUoS methodology reflects an arbitrary G:D split proportion. It is appropriate to investigate the possibility of altering the arbitrary split of transmission costs between G:D. Examine current split to ensure that generators located within GB are not at a competitive disadvantage to those exporting into GB from Europe. (Theme 6)
NGET, SCDI, Orkney Islands Council, OREF, Pelamis Wave Power, Renewable UK	The current TNUoS methodology does not consider the treatment of transmission links to island users. (Themes 2 and 6)
Centrica, DONG, EDF Energy, NGET, HIE, Orkney Islands Council, Renewable UK, RWE, SCDI, Statkraft, Statoil	The current TNUoS charging methodology does not reflect the growth of an offshore transmission network. It is appropriate to examine the impact of OFTO revenues and the dominance of the local charge under the current charging mechanism. (Themes 2, 3 and 6)
Centrica, OREF, Pelamis wave power, Renewable UK, RWE, SSE, SCDI, Scottish Government	The current TNUoS methodology contains locational charging elements and socialised charging elements. It is appropriate to consider the current split between these elements and the treatment of local (user specific) infrastructure assets and the local/wider boundary in particular (ie extension of the principle of postalisation to all Local Infrastructure Assets or the maintenance of some sort of user specific signal). (Themes 2, 3 and 6)

Drivers for Change

9.5 The Working Group discussions of the issues under this Theme primarily related to the position of the revenue recovery split of 27:73 between generation and demand users respectively.

9.6 There were three potential reasons for change highlighted by the Working Group in this area:

What is Theme 6?

Theme 6 seeks to review the proportion of TNUoS Transmission Revenue collected from generation and demand users of the network. Currently this proportion is equal to 27% and 73% respectively. The interaction with revenue collected through local circuit and local substation charges is also considered.

i) The relative competitive position of GB generators to competitors based in interconnected EU markets;

ii) The binding EU Tarification Guidelines, arising from the Regulation on Cross Border Electricity Exchanges;

iii) The proportion of total transmission revenue collected from offshore generators through the local circuit and local substation elements of the tariff.

9.7 After some debate the Working Group agreed that the timescales for a change in the G:D split would likely be driven by (ii), above, and that the ultimate percentage of total revenue to be collected from generators would likely be driven by (i).

9.8 A key argument for change is to improve alignment of GB generation with EU competitors. It is widely asserted that the majority of European transmission system generator users pay a lower proportion, or even 0%, of total transmission costs. However, it was noted that one of the difficulties of determining an appropriate G:D split was the lack of comparative data with neighbouring EU charging regimes. For example, it was argued that some European generators may face large connection charges that are not considered transmission use of system charges. Some Working Group members believed that more analysis should be undertaken to better understand what European generators pay before the percentage to be recovered from generators could be decided.

9.9 One member of the Working Group provided anecdotal evidence from specific projects that they had worked on in Europe. Those in the neighbouring countries of Germany, The Netherlands and Belgium indicated that all transmission losses, ancillary services and Use of System charges are paid for exclusively by demand.

9.10 Another member of the group provided the Working Group with a review of the ENTSO-E "Overview of transmission tariffs in Europe Synthesis" report for 2011 (published in May)[32]. This indicated[33] that of the 32 European countries reviewed twenty had a 0% sharing factor for network charges for generation, four countries had between 0% and 10%, two countries between 10% and 20%, five countries between 20% and 30% (which included GB) and one country in excess of 30%. In the context of countries currently interconnected with GB, France applied 2% to generation, Ireland 25% and Holland 0%. In terms of future potential interconnections, Belgium and Norway apply 0% and 35% respectively to generation.

9.11 In terms of connection, the report indicated[34] that 19 of the 32 countries had a 'shallow' connections approach for generation with the remaining having either 'shallow to partially deep', 'partially deep' or 'deep' arrangements. In the context of countries currently interconnected with GB, France applied 'shallow', Ireland 'shallow to partially deep' and Holland 'shallow'. In terms of future potential interconnectors, say, to Belgium and Norway they both applied 'shallow'.

9.12 A number of working group members, who had also read the above report, considered that it was sometimes unclear about the exact types of cost which had been incorporated into the analysis, with the information for some countries being clearer than others. Despite the uncertainties surrounding what EU generators pay, there was a general consensus within the Working Group that reducing the G proportion of transmission charges would bring

[32] https://www.entsoe.eu/media/news/newssingleview/article/entso-e-publishes-its-overview-of-transmission-tariffs-in-europe-2011/

[33] On page 6 of the ENTSO-E report

[34] On pages 30-31 of the ENTSO-E report

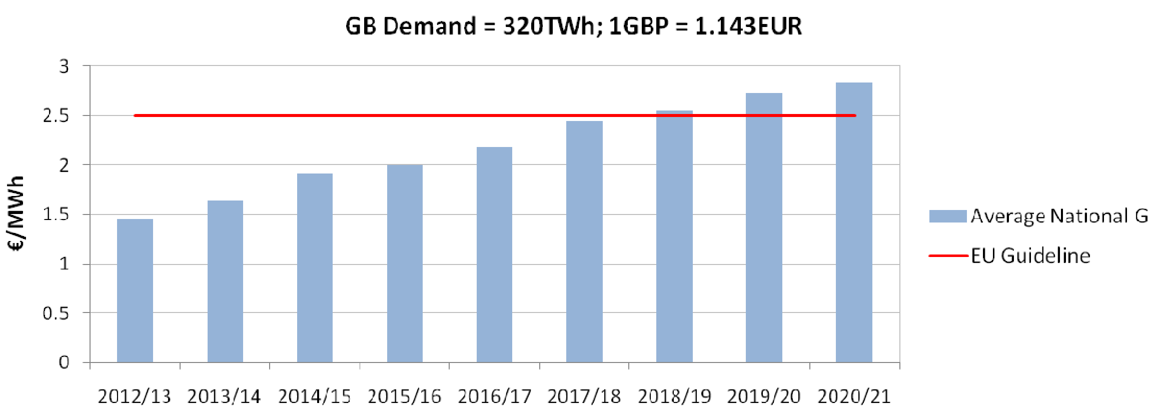
GB generators more in line with the direction of travel in the EU and that this could benefit cross border trading.

9.13 A number of Working Group members also considered that the binding European Tarification Guidelines would require a change to the current GB G:D split in the medium-term. These guidelines require that the value of the 'annual national average G' within Great Britain, Republic of Ireland and Northern Ireland should not exceed a value of €2.5/MWh. Currently GB generators contribute approximately €1.5/MWh.

9.14 The value of the 'annual national average G' is the annual total transmission charges paid by generators divided by the total measured energy injected annually by generators into the transmission network. The 'annual average G' excludes any charges paid by generators for physical assets required for the generators connection to the transmission system (or upgrade of the connection) as well as any charges paid by generators related to ancillary services or any specific network loss charges paid by generators. This was interpreted by the Working Group as referring to transmission revenue collected through TNUoS charges only (i.e. excluding BSUoS, connection charges and losses).

9.15 Analysis was presented to the Working Group to ascertain when the EU €2.5/MWh guideline would be likely to be breached. It was estimated that, in the context of GB, the EU Tarification Guidelines could be breached as early as 2015/16 using 'worse case' assumptions and by 2018/19 using assumptions considered to be a 'central case', shown in Figure I, below.

Figure I: Illustrative Future Average National G - Central Case



9.16 Although the accuracy of these GB estimates are dependant on the actual electricity volumes, the agreed level of transmission investment required, the quantity of offshore transmission, and exchange rates and inflation, the Working Group concluded that the proportion of transmission costs recovered from GB generators would need to be reduced in the medium term and hence this should be considered in the development of options for transmission charges going forward.

9.17 Additional discussions also took place regarding the impact of increased generation local charges, primarily as a result of future offshore connections, and the consequential effects on generation residual tariffs through adherence to a 27:73 G:D revenue split. This discussion is covered in further detail below and in Annex 6.

Options discussed

9.18 The Working Group considered three broad options for the overall G:D split. These options would address reasons (i) and (ii) for change, outlined in paragraph 9.6, above:

i) no change (i.e. maintain 27/73 split);

ii) a single change from 27/73 to another ratio; and

iii) phased change to another ratio (e.g. dropping G% gradually).

9.19 The Working Group and Ofgem agreed that there could only be a change to the current G:D split arrangements if there was convincing evidence to justify such a change and that the implications had been fully considered.

9.20 Some members of the WG noted the timeframes for change would have a significant impact upon retail markets. For that reason, it was noted that a minimum eighteen month to two year transition period would most likely be required in any change process which reduced the G element and, correspondingly, increased the D element. This is discussed in more detail in Section 10 - Implementation / Transitional Issues.

9.21 The Working Group also noted that a potential movement to the application of an average G=0 split would require more negative generator charges relative to the current position. The comment was made that this could be perceived as one set of generators offsetting the costs of another set.

9.22 Some members of the Working Group noted that, as a general rule, if the development of renewable and other low carbon generation is the key focus of Project TransmiT, then the proportion of costs recovered from generators should be set to 0% to encourage a higher proportion of marginal plant to develop. Other members noted that the issue of renewables support should be entirely separate from specific changes to the TNUoS charging methodology and the Project TransmiT SCR process (as all generation types, including carbon intensive generators would be affected equally be a change in G:D split), and is a matter for DECC. Some members noted that this was a cash-flow benefit to all marginal generation investors, not just those investing in renewable plant. The potential effects on the development of low carbon nuclear generation were not considered.

9.23 In order to address reason (iii) for change, outlined in paragraph 9.6 above, the two Working Group members who raised this issue presented on the growing effects on generators' TNUoS tariffs due to the connection of offshore generators. These members believed that, the resultant reduction of the residual, payable by all generators, was an issue that needed to be addressed.

9.24 The WG members who raised this as an issue provided a range of views on why they believed this is an issue. They considered that the current treatment of revenue collected from local transmission circuit charges:

- Provides a subsidy to onshore generators,
- Decreases the stability of tariffs,
- Is to a large extent an unintended consequence,
- Is incongruous from a presentational point of view.

9.25 All members of the group agreed that the existing fixed percentage of transmission revenue recovered from generators (i.e. 27%), coupled with the increasing proportion of this revenue collected from offshore local circuit and local substation tariffs, would reduce the residual element of TNUoS tariffs applicable to all generators. However, as the residual element applies to all generators and locational differentials would be maintained between generators, many believed that this was not a problem.

9.26 A number of options were discussed for managing the perceived issue of increasing generation local charges within a 27:73 G:D split. These included;

i) Offshore transmission assets become connection assets and are recovered in full from offshore users through connection charges (discounted as connection charges out of the scope of Project TransmiT)
ii) Offshore local transmission assets only charged 90% of cost G=90% D=10;%.
iii) Remove local transmission assets from G/D split and alter onshore G/D split; to ensure overall G = <27%.
iv) Offshore local transmission asset charged G=27% D=73%;
v) Offshore local transmission assets charged G=90% but local charge based on 400kV OHL cost (i.e. expansion factor 1); and
vi) No local transmission assets.

9.27 Discussions centred around the effect of these options on the proportion of TNUoS revenue recovered from offshore generators, onshore generators and demand users. Some in the Working Group expressed concerns with some of the options, believing that these amounted to a 'subsidy' from onshore to offshore generation. Some questioned the validity of this as an issue to be resolved.

9.28 Despite significant debate, the majority of the Working Group were either not convinced that this was an issue that needed to be addressed, or did not believe that it needed to be addressed as an immediate priority. Two members disagreed with this assessment. The detail of options discussed are presented in further detail in Annex 6.

Working Group Conclusions and Position on Theme 6

9.29 There was a consensus amongst the group that reasons (i) and (ii) for change, highlighted above, are sufficient to warrant a reduction in the proportion of transmission revenue recovered from generators.

9.30 The Working Group agreed the following treatment of G:D split in the modelling scenarios:

- April 2012 - March 2015: The total revenue to be recovered from generation is calculated as 27% of the total TO target revenue to be collected via TNUoS charges for each financial year.
- April 2015 – March 2030: Reduce G proportion to 15% (and increase D proportion to 85%) to comply with the EU Tarification Guidelines. It was noted that this reduction would be sufficient to ensure no breach took place before 2020 in the 'worse case' assumption.

9.31 No consensus was reached regarding any proposal to manage generation local charges (and their conseqences on the residual TNUoS tariff) via changes to the G:D split. The majority of the Working Group did not believe that this was an issue that needed to be addressed.

9.32 The Working Group agreed that the most appropriate way of changing the split between Generation and Demand would be a single step change with sufficient notice to allow parties the time to adapt. This is also discussion in Section 10 – Implementation/Transition Issue.

10 Implementation / Transitional Issues

10.1 The Working Group considered the transitional issues that could arise if the transmission charging SCR were to result in a direction from Ofgem to make a significant change to the current charging methodology. In order to assist with this a number of members put forward papers outlining the potential issues that may arise.

10.2 It was widely agreed that it was important that a decision on this issue is achieved as soon as possible. There was a general concern that both existing users and new entrants alike are finding it more difficult to make business decisions, such as planning new generation investment, in light of the current uncertainty as to how Project TransmiT will conclude.

10.3 The Working Group was mindful that an Ofgem direction would not be the end of this process and that potentially a considerable amount of work still lay ahead to progress any necessary proposals through the CUSC modification process, dependent on the extent of change being proposed. However, it was agreed that a timely decision from Ofgem would allow transmission users to operate and plan their businesses with more confidence, even if the new arrangements were not to be implemented until sometime later.

10.4 There was a significant amount of debate within the Working Group regarding the impact that changes in charges could have on customers and different categories of transmission user. There was a general consensus that the nature of some of the proposed changes was such that there was the potential for significant impacts to be felt by customers and market participants alike, and that it was important that the industry was in a position to manage this appropriately.

10.5 There was a discussion about whether certain types of market participant were able to cope better with changes than others, with some members suggesting that smaller independent parties would be more exposed than larger more vertically integrated ones. Others believed that this was not the case and that all generation companies for instance tended to make business decisions on a plant by plant basis. It was agreed however by the Working Group that all transmission users would be impacted to some extent by any significant changes that were to occur.

10.6 It was noted that an important consideration was the arrangements that existed between suppliers and their customers. Suppliers need to be a position to manage this relationship appropriately in order to minimise the disruption that any changes to charges would have on customers and on their businesses. The impact of any changes would be dependent on the types of deals that customers are signed up to, but it was agreed that as a general principle suppliers and customers needed sufficient notice of any changes in order to be able to react accordingly.

10.7 It was also agreed that generators needed sufficient time to be able to respond to new price signals. The Working Group noted that at present generators are required to give a full financial year and five business days' notice before they are able to reduce their transmission entry capacity.

10.8 There are also a variety of commercial agreements such as Power Purchase Agreements or contracts to provide reserve which can commit generators to operating their plant for a number of years. The group considered that the notice requirements for generators appeared to be similar to those of suppliers.

10.9 From a transmission company perspective the potential shift of costs from TNUoS to BSUoS for some changes may require a review of the current balancing services incentive scheme, which is due to expire in March 2013. In addition, it was noted by the Working Group that any change is likely to require changes to IS systems (e.g. invoicing) which would need to be considered in implementation timescales.

10.10 The Working Group considered what a reasonable lead time for implementation might be and agreed that, were Ofgem to conclude on the SCR in its proposed timescales, an appropriate time to implement any new arrangements would be from April 2014. The Working Group believed that an April 2013 implementation was the absolute earliest date that would be feasible, given the significant effort required following a SCR direction from Ofgem, in order to develop any proposals fully through the CUSC modification process.

10.11 However, there was concern that this would still leave customers and other transmission users exposed to cost implications that they would not be able to manage appropriately. The Working Group also noted that it was the notice period rather than the proposed implementation date which was important and that the above dates would have to move accordingly should there be a significant delay to Ofgem's SCR conclusions.

10.12 The Working Group also discussed whether or not it would be feasible or beneficial to implement any new arrangements part way through a charging year. It was concluded that this was not desirable for a number of reasons including the impact that this would have on companies' internal processes such as business planning and the potential disruption that this could cause to the main supply contracting rounds with large customers. It was also felt that a mid-year tariff change would be more complicated and therefore more costly to implement and which would potentially undermine or negate any benefits of bringing in changes to tariffs at a slightly earlier date.

10.13 The issue of phasing in of changes to charges was also considered by the Working Group. The Working Group concluded that this would also be unnecessarily complicated and that an approach that implemented any changes fully would be more appropriate.

10.14 Therefore, in summary the Working Group concluded that:

- There should be an implementation date of April 2014, if Ofgem's SCR conclusions are issued in the timescales proposed, with an earliest feasible date being April 2013.
- A significant delay to Ofgem's SCR conclusions would require these dates to be moved accordingly.
- That implementation should occur fully at the implementation date (i.e. no phasing) and that a mid year change would be undesirable.

10.15 Further detail of the issues implementation and transitional issues raised in the Working Group is included in Annex 9 of this report.

11 Recommendations on Models for Assessment by Redpoint

11.1 The following tables summarise the decisions made by the Working Group on how Redpoint Consulting should model the three charging options in their impact assessment for Ofgem.

Status Quo (ICRP extended to 2030)	
Theme	**Outcome**
1	- no change
2	- no change
3	- no change - noted that some island connections could be classed as wider for charging purposes and would therefore have a security factor of 1.8
4	- model HVDC links that parallel the onshore network as an equivalent AC circuit by: i) determining impedance from an HVDC power flow calculated as the average of a ratio of total network boundary rating versus HVDC link rating for all boundaries that the link crosses ii) No consensus on calculating expansion factor for the HVDC link; choice of either: a) excluding convertor costs or b) including all costs
5	- no change
6	- move from a G/D revenue collection split of 27/73 to 15/85 from 2015

What information did the Working Group provide to Redpoint?

The Working Group passed their conclusions on how each individual theme should be modelled in the impact assessment for each of the Status Quo, Improved ICRP and Postage Stamp charging models.

Theme	Improved ICRP Outcome
1	- Dual background approach to the Transport Model used in calculating locational differentials (Peak Security and Year Round backgrounds) - Background scaling factors for plant types consistent with NETS SQSS proposals under GSR009 - The use of a two part tariff commensurate with the dual backgrounds - No consensus on plant contributing to tariff elements; choice of: i) Intermittent plant only contributes to Year Round element; or ii) All plant contribute to both Peak Security and Year Round element - No consensus on tariff calculation for Year Round element; choice of: i) TEC only ii) TEC x specific historic load factor iii) TEC x generic load factor for plant type iv) TEC x specific forecast load factor (with reconciliation) v) TEC x ex-post MWh
2	- no change to zoning criteria or local/wider boundary
3	- no change - for island connections that would be classed as wider for charging purposes and that have significant sections of single circuit (i.e. islands with single circuit sub-sea connections) the expansion factor for this section would be calculated by dividing the unit cost by 1.8
4	- focus on HVDC links only - model HVDC links that parallel the onshore network as an equivalent AC circuit by: i) Determining impedance from an HVDC power flow calculated as the average of a ratio of total network boundary rating versus HVDC link rating for all boundaries that the link crosses ii) No consensus on calculating expansion factor for the HVDC link; choice of either: a) excluding convertor costs or b) including all costs
5	- no change
6	- move from a G/D revenue collection split of 27/73 to 15/85 from 2015

Theme	Postage Stamp Outcome
1	- no consensus on reflecting user characteristics; choice of allocating charges based on: i) MW or ii) MWh
2	- no consensus on differentiation of costs; choice of: i) maintain existing local/wider boundary ii) remove local/wider boundary and socialise all costs iii) continue to calculate an ICRP based demand charge iv) charge demand on the same basis as generation (i.e. socialised)
3	- not relevant for wider tariffs - no change for local if maintaining local/wider boundary
4	- not relevant for a postage stamp model
5	- no change for local if maintaining local/wider boundary
6	- move from a G/D revenue collection split of 27/73 to 15/85 from 2015

Annex 1 – Working Group Members

	Name	Representing
1	Ricky Hill	Centrica
2	Helen Snodin	Representing Scottish Renewables
3	Robert Longden	Mainstream Renewable Power
4	Simon Lord	First Hydro company
5	Ivo Spreeuwenberg	NGET
6	Michael Dodd	ESBI international
7	Paul Jones	Eon
8	Louise Schmitz	EDF Energy
9	Frank Prashad	RWE npower
10	Tim Russell	Advisor to the Renewable Energy Association
11	Garth Graham	SSE
12	James Anderson	Scottish Power
13	Stuart Cotten	Drax Power Limited
14	Guy Nicholson	RenewableUK
15	Chair	Ofgem
16	Secretariat	Ofgem

Who is the Working Group?

The Working Group is comprised of 14 industry technical experts and is chaired and minuted by Ofgem.

Annex 2 – Working Group Terms of Reference

Terms of reference for industry technical working group

This appendix sets out the terms of reference for the technical working group to support the development of the technical detail of potential options for generation and demand Transmission Network Use of System (TNUoS) changes, and indicative dates for the meetings. The draft terms of reference include our initial thoughts on the high level charging principles and assessment criteria to be applied by the working group in developing practical technical changes associated with each of the broad charging options we have identified.

1. Group composition:

Chair: Ofgem
Members: Up to a maximum of 15 industry representatives

The use of an alternate may be permitted depending on the circumstances. Any alternate will be expected to contribute proactively to the discussion and will be required to provide comments in both written and verbal form at meetings on the technical solutions and the form of methodology changes required under the broad options for change.

2. Purpose of the group

The purpose of the working group is to support the development of the technical detail of potential options for TNUoS changes.

The potential options for TNUoS changes within scope of the SCR range from postalised charging options to improvements to the current 'Incremental Cost Related Pricing' (ICRP) approach.

A key focus of the group will be to develop the technical detail associated with the options for potential change, building on the themes we have identified as requiring most urgent attention following consideration of the information received since the launch of TransmiT. The table below summarises the six broad themes of potential changes to TNUoS charging we have identified based on all issues raised so far. Each of the themes is applicable to the two broad options for potential TNUoS change in the shorter term.

Theme
1. Reflecting characteristics of transmission users
2. Geographical/topological differentiation of costs
3. Treatment of security provision
4. Reflecting new transmission technology
5. Unit cost of transmission capacity
6. G:D split

3. The technical working group

We envisage that the technical working group will meet on approximately a fortnightly basis from the week commencing 18 July 2011. At this stage, Ofgem envisages the need for six meetings, between July and September 2011, concluding with the production of a final agreed and accepted written report summarising the group's technical conclusions and changes against each of the charging options. We expect that this report will provide a valuable contribution to the development of proposals for change that we intend to consult on in October 2011.

We expect National Grid Electricity Transmission (NGET) to be the lead party responsible for coordinating the drafting of the technical working group report. We will discuss the process for doing this at the first meeting.

We are specifically seeking the support of the working group to develop detailed changes under each of the themes identified across the two broad options. In particular, we expect the working group members to play a proactive role in contributing their technical expertise to the group and developing the form of methodology changes required under the broad options for change.

The conclusions of the working group will provide an important input to our thinking, but it is not a decision making body. Ofgem retains the responsibility to develop any proposals for changing the existing TNUoS charging arrangements and for these to be consulted upon with the wider industry in a transparent and open manner under the SCR process.

We are looking to bring together a small number (around 15) of technical experts who are representatives of all the key stakeholder groups. This necessarily rules out every interested party having a seat on the group.

All materials generated by the group will be published on the designated TransmiT section of the Ofgem website. Views on these materials will be welcome from all parties, including those who do not attend the working group. All responses received will be published on the web forum. In this way we can create a wider virtual forum to enhance the work of the group. We would also encourage anyone to approach the group if they identify specific issues they consider the group should take into account. We will set out a mechanism for doing this following our first meeting.

In addition, there will be further consultation and stakeholder events in the coming months to provide further opportunity for all stakeholders to feed into our review of the electricity transmission charging arrangements. There will also be additional stakeholder events to give all interested parties an opportunity to participate in the SCR process.

4. Scope of work

- Help Ofgem to identify the technical solution and the form of the methodology change required to give effect to this solution for each of the potential TNUoS change options; postalised charging options and improvements to the current ICRP approach.

- Help Ofgem to collect and review relevant evidence relating to the effectiveness of the current GB charging regime.

- Provide comment and expert technical views on the relative priorities of the six broad themes we have identified as requiring most urgent attention and detailed aspects of the current charging methodologies that require change under each of these themes applicable to the two broad options for potential TNUoS change.

- Comment on likely impacts of recommended changes on all relevant stakeholders including different types of generation and consumers, the achievement of relevant energy policy goals, as well as the appropriateness of the high-level objectives and principles.

5. Commitment

Between mid July 2011 and September 2011, approximately 6 days will be required from each member to attend 6 working group meetings. The successful representative will be required to provide comments in both written and verbal form at meetings on the technical solutions and the form of methodology changes required under the broad options for change.

The members are expected to attend meetings at Ofgem's offices in Glasgow and Millbank.

6. Deliverables

The key deliverable is:

- **A publishable report by mid September 2011** – this written report should summarise key information from the working group process in a form which is fit for publication and does not contain any confidential information and is factually correct and accurate. The report will briefly summarise the technical debate at each of the working group meetings and detail the technical solutions agreed and the form of methodology changes required under each of the broad options for change.

7. Charging principles and assessment criteria

It is important for us to make well-informed and robust decisions on the options to be adopted for the short term, if any. Ultimately, we want to develop a better understanding of the interaction between potential changes to the charging arrangements for allocating transmission costs (ie including costs relating to transmission assets and costs relating to system operation, such as constraints and losses) to users and decisions of generators in locating new plant, making retirement decisions and the impact of these decisions on transmission investment.

To help us assess the two broad options for potential change, we propose to assess the impact of these options in four key areas:

- The economic efficiency in both the short run (efficiency in generation despatch) and the long run (efficiency in transmission infrastructure investment decisions);
- The development of renewable generation across GB and the achievement of domestic environmental targets;
- Other areas of consumer interests such as security of supply;
- The efficient use of cross border transmission infrastructure and free trade of power across neighbouring European networks.

The above criteria have been developed following consideration of all the information received through our consultation process, from our dialogue with stakeholders, participation in discussions in Europe and academic advice.
Furthermore, we note that there are some 'must do' constraints that must form the baseline assessment of each of the emerging options associated with legal compliance, including requirements on transparency and non-discrimination.

We recognise that there are potential trade-offs between the impacts of any charging option in each of the above categories. For example, options that focus solely on the economic efficiency of the GB system may not all be compatible with the need to facilitate maximising the potential renewable generation development.
The working group assessment of the options therefore has to consider the impacts in each of the four individual areas, and seek to identify those that would deliver an overall benefit relative to the system as a whole.
In addition to the assessment of impacts in the above key areas, we also will consider a number of practical issues relating to the applicability of the options. In particular the simplicity and transparency of the arrangements (which to some degree is linked with the impact of a particular charging option in economic efficiency) and the transition / implementation cost in the context of both applying to postalisation and improved ICRP options.

8. Organisation of meetings

We envisage that the working group will meet on approximately a fortnightly basis from the week commencing 18 July 2011. In the first instance Ofgem envisages the need for six meetings between July and September 2011, concluding with the production of a final written report summarising the group's technical conclusions and changes for each of the charging options.

The first meeting will take place in Ofgem's offices in Glasgow on Tuesday, 19 July 2011. The meeting will discuss the draft terms of reference and comment on the potential technical solutions for each of the six broad themes identified and establish the priority for future working group discussion. Subsequent meetings will address the agreed themes in the context of both applying to Postalisation and Improved ICRP options.

9. Proposed meeting schedule

Meeting 1	Tuesday 19th July (Ofgem's offices in Glasgow)	
Meeting 2	Monday 1st August (Ofgem's offices in London)	Conference room 8
Meeting 3	Tuesday 9th August (Ofgem's offices in Glasgow)	
Meeting 4	Thursday 18th August (Ofgem's offices in London)	Conference room 9
Meeting 5	Tuesday 30th August (Ofgem's offices in London)	Conference room 9
Meeting 6	Friday 9th September (Ofgem's offices in London)	Conference room 9

A3.1 Reflecting the Characteristics of Users – National Grid Improved ICRP Proposal

The following brief describes a proposal given by National Grid to the Project TransmiT SCR Working Group. The proposal makes a number of suggested incremental improvements to the existing ICRP methodology used to calculate users' TNUoS charges. These can be incremental improvements can be broken down into;

- Proposed changes to the Transport model
- Proposed changes to the Tariff model
- Proposed proxy for year round charge

A3.1.1 Proposed Changes to the Transport Model

The locational element of the wider TNUoS charge is calculated through consideration of the relative impact of an additional MW, applied on a nodal basis, within a DC load flow. Currently, the setting of this DC load flow is based on a peak security background, with all contracted generation uniformly scaled to match the peak MW demand.

Under this National Grid proposal, a year round background would be used alongside peak security considerations, to represent future transmission system development requirements. This year round background would group generation into types based on their technology and perceived future operating regimes, and then either flat or variably scale their aggregated capacity to meet demand. The level of scaling is shown in ***Table II*** below with flat scaling in black, and variable scaling in grey. It should be noted that the peak security background sets intermittent generators and interconnectors to zero; i.e. it assumes no contribution from energy sources that cannot be controlled at times of peak demand. The scaling factors given in ***Table II*** are a result of the detailed cost-benefit analysis work undertaken by the NETS SQSS review group as part of GSR009 [35] to represent investment requirements for year round conditions in a single snapshot.

It is proposed by National Grid that the scaling factors given in ***Table II*** are treated similarly to other charging data which may change with time (e.g. expansion constant) and that they be reviewed at each Transmission Price Control Review (TPCR). If the NETS SQSS intermittency proposals[36] currently being considered are accepted, and similar scaling factors are used within the NETS SQSS, then it is proposed that future revisions of scaling factors for charging will be aligned with any revised NETS SQSS scaling. In the event that the NETS SQSS intermittency proposals do not proceed, then the underlying cost-benefit analysis work undertaken by the NETS SQSS review group will continue to represent a reasonable approach to ascertain the figures required to provide a single snapshot of year round operation.

[35] NETS SQSS Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation – GSR009 Consultation Document v1.0 11th June 2010; http://www.nationalgrid.com/NR/rdonlyres/E22B1547-D4CC-4F88-AEEF-C76305718C25/41720/GSR009SQSSConsultation.pdf

[36] Minimum transmission capacity requirements in the Security and Quality of Supply Standard; http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/SQSS/Documents1/GSR009%20Impact%20Assessment.pdf

Generator type	TEC in Transport Model	Current methodology	Peak Security Background	Year Round Background
Intermittent	5,460	65.5%	0%	70%
Nuclear & CCS	10,753	65.5%	72.5%	85%
Interconnectors	3,268	65.5%	0%	100%
Hydro	635	65.5%	72.5%	66%
Pumped Storage	2,744	65.5%	72.5%	50%
Peaking	5,025	65.5%	72.5%	0%
Other (Conventional)	61,185	65.5%	72.5%	66%
(source 2011/12 Transport Model)				

Table II – Proposed ICRP generation background scaling factors

In the above table, peaking plant is defined as oil and OCGT technologies. In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) will apply.

Utilising the existing Transport Model, generation will be scaled, or set, as appropriate using the factors in ***Table II*** to create two balanced DC load flow models. It should be noted that, consistent with the current DC load flow model, no circuit ratings would be considered, and no level of redundancy would be assessed at this stage.

Flows on these two models will then be compared. The model giving rise to the higher flow on a circuit will be considered to be the 'triggering criterion'. Triggering criteria for all circuits in the model will then be ascertained and recorded; i.e. circuits will be tagged as either 'peak security' or 'year round'. In the rare event that both triggering criteria give rise to identical circuit flows, then the peak security background will be taken as the triggering criterion. This reflects the order of priority given to these two backgrounds when considering transmission investment requirements.

As outlined above the current ICRP methodology uses an incremental MW applied to a DC load flow at each node in turn (and removed at the reference node), in order to establish the effect of that additional MW on the transmission system as a whole. Under the (National Grid) proposed methodology, this assessment would be carried out at each node in turn for both peak security and year round models.

Currently a single reference node is selected. This selection is arbitrary as, due to the re-referencing process, only the relative locational charges are of relevance. However, due to the use of two background criteria in the Transport Model, the re-referencing process will become more involved. In order to simplify this revised re-referencing process as much as possible, it is proposed to use a distributed reference node rather than a single reference node. This would effectively split the incremental 1MW of demand from a single point to proportions on each demand node in the Transport Model. The proportion would be based on the background nodal demand in the model. For example with a GB demand of 60GW in the Transport Model, a node with a demand of 600MW would contain 1% of the distributed reference node (i.e. 0.01MW).

On a (transmission) circuit by circuit basis, the impact of the incremental MW (i.e. the net change in power flow) needs to be recorded for each circuit's triggering criterion. For each circuit an incremental MWkm needs to be established and tagged to the appropriate triggering criterion; i.e. peak security or year round. This process results in a set of peak security MWkm and year round MWkm which combined amount to approximately the same level of incremental MWkm as the existing ICRP approach. For generation in a 2011/12 model, net peak security MWkm represent 13.5% of the total incremental MWkm.

A summary of the (National Grid) proposed process is given below in Figure II.

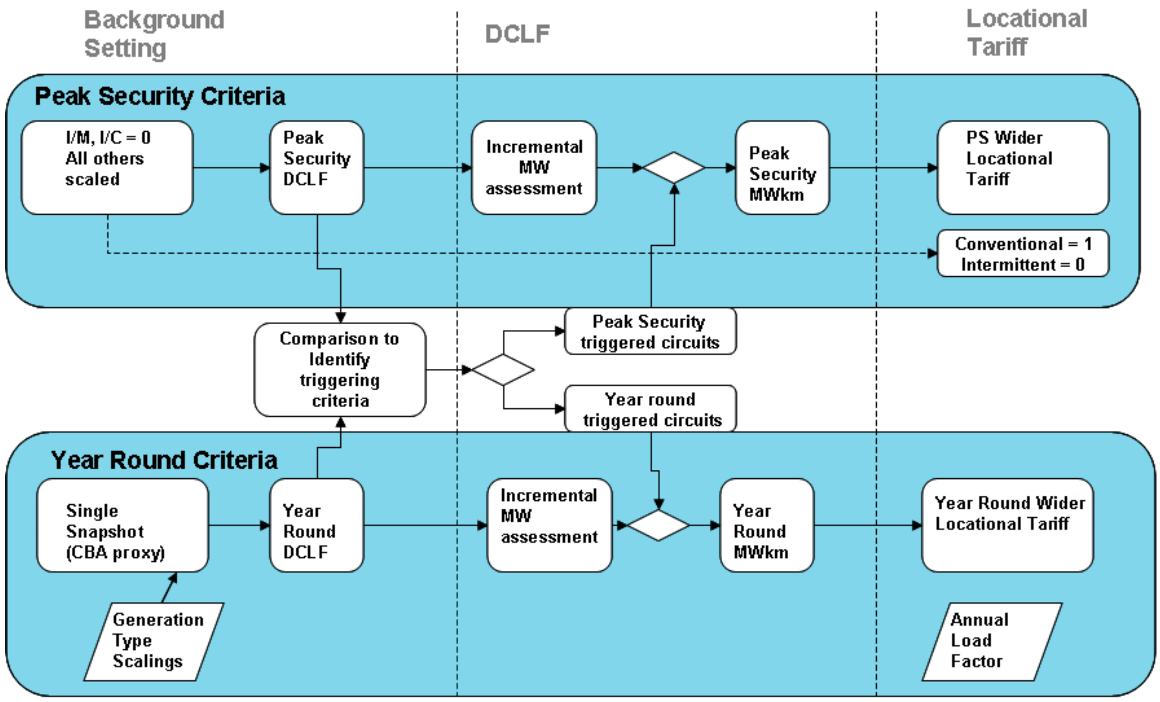


Figure II – Proposed dual background TNUoS charging methodology

A3.1.2 Production of Tariffs

A3.1.2.1 Generation Tariffs

It is intended that the incremental MWkm for demand security and year round backgrounds be converted into tariffs, which would ultimately lead to the creation of two wider locational tariffs:

- *Peak Security Wider Tariff.* It is proposed that the peak security wider tariff for intermittent generation will be zero (for both positive and negative peak security zones) due to its lack of contribution to the need for transmission network investment to ensure demand security. Conventional plant will pay the peak security element based on their TEC capacity (MW).

- *Year Round Wider Tariff.* It is proposed that this tariff is scaled by a suitable proxy that is representative of the long term year round impact of the user on the transmission system. In this proposal this is suggested to be via an annual load factor (ALF) specific to each particular generator. Further details on the National Grid proposal for ALF are provided in section A3.1.3, below.

Hence, under National Grid's proposal a generator's TNUoS charge would be comprised of the following four components;

- Peak security wider zonal charge
- Year round wider zonal charge
- Residual charge
- Local substation charge
- Local circuit charge

This section describes the proposed approach to each of these tariffs in turn.

A3.1.2.1.1 Impact on local charges

Local charges consist of a local (transmission) substation charge and a local (transmission) circuit charge. National Grid's proposal will not to alter the local substation tariff calculation, and therefore will have no impact on local substation charges. Similarly, it is not proposed that there is any explicit change to the calculation of local circuit charges. However, due to the categorisation of (transmission) circuits as either peak security or year round, there will be an indirect impact on local circuit tariffs. At this stage it is proposed that all local circuits will have a year round triggering criterion, so as to avoid any perverse incentives in the choice of level of security for design variations on local circuits.. *(source 2011/12 Transport Model)*

It should also be noted that National Grid's proposal does not intend to alter the extent to which circuits are defined as local or wider, dealt with under Theme 2 of the SCR Working Group report.

A3.1.2.1.2 Wider locational tariffs

It is proposed that locational tariffs are derived, as per the existing transmission charging methodology, from the nodal marginal km output from the Transport Model, and the associated zoning exercise (as described in section A3.1.2.1.2.3 below). However, as there are two sets of generation MWkm created in the Transport model, corresponding to the peak security and year round criteria, there will ultimately be two wider locational tariffs for generation; a peak security tariff and a year round tariff. Conversion from zonal MWkm to unadjusted tariffs follows the existing process through multiplication by the expansion constant and locational security factor. However, the added complexity caused by two locational tariffs for generation has required changes to the re-referencing process and proposals for this are described in section A3.1.2.1.2.4 below.

Whilst both these tariffs are charged based on a generator's TEC (MW) capacity (as described in section A3.1.2.1.2.5 below), the actual application for specific users will depend on that user's characteristics and is different for both tariffs. This is described in more detail in sections A3.1.2.1.2.1 and A3.1.2.1.2.2 below.

A3.1.2.1.2.1 Peak Security locational tariff

It is proposed (by National Grid) that the peak security tariff is only levied on those generators which have a high probability of operating at significant volumes during peak demand periods. Transmission network development for peak security requirements is triggered by such generation and hence it is proposed that it is appropriate that a proportion of the TNUoS charge be directed towards this generation. As noted above, for the generation background in a 2011/12 model, the net peak security MWkm represent 13.5% of the total incremental MWkm.

The revenue from a specific generator due to the peak security locational tariff is equal to that tariff multiplied by the forecast generation capacity. This also needs to be multiplied by the appropriate peak security flag. The peak security (PS) flags indicate whether a generation type contributes to the need for transmission network investment at peak demand levels. As such, they are consistent with the background generation scaling used in the peak security Transport Model assessment (see Table II above), and are given below in Table III.

Generation type	**PS flag**
Intermittent	0
Other	1

Table III– Peak Security Flags

The revenue recovery, for peak security purposes, of a generator is calculated as;

$$ITRR_{GiPS} = G_{Gi} \; x \; SF_{PS} \; x \; ITT_{GPS}$$

Where; $ITRR_{GiPS}$ = Initial Transport Revenue Recovery for generator is due to System Peak Security criterion

G_{Gi} = Forecast generation capacity

F_{PS} = Peak Security flag appropriate to that generator type

ITT_{GPS} = Initial Transport Peak Security Tariff (£/kW)

A3.1.2.1.2.2 Year Round locational tariff

National Grid's analysis of the relationship between load factor and transmission constraints has indicated a linear relationship largely independent of generation technology (see section A3.2 for further details). It is therefore proposed that a generator's specific output over an extended period of time is reflective of the assumption used in transmission network planning timescales, and thus the transmission investment it triggers. It follows that the year round locational tariff for a generation user should be based on the specific output of that generator over time.

It is proposed that historic generation annual load factors (ALF) be used as scaling factors, as set out in section A3.1.3. For clarity, the formula for revenue recovery for year round charging purposes is calculated as below;

$$ITRR_{GiYR} = G_{Gi} \; x \; ITT_{GYR} \; x \; ALF_{gen}$$

Where; $ITRR_{GiYR}$ = Initial Transport Revenue Recovery for generator is due to Year Year Round criterion

G_{Gi} = Forecast generation capacity

ITT_{GYR} = Initial Transport Year Round Tariff (£/kW)

ALF = Annual Load Factor specific to that generator

A3.1.2.1.2.3 Setting of generation charging zones

The current methodology for the setting of generation charging zones describes three criteria for zonal assessment. Specifically, the first criterion requires that these zones should contain relevant nodes whose wider marginal costs are all within +/-£1.00/kW across the zone (i.e. a £2.00/kW spread). Under this (National Grid) proposal it is recommended that zonal assessment continues to be undertaken such that wider marginal costs are within +/-£1.00/kW (i.e. a £2.00/kW spread).

It should be noted that, unless there are exceptional circumstances, generation charging zones are normally fixed for the duration of each Transmission Price Control Review. It is therefore recommended that there is no zonal reassessment until the next price control review period which is currently anticipated to come into effect in 2013.

A3.1.2.1.2.4 Re-referencing of locational tariffs

Presently, for both generation and demand users, zonal marginal km (ZMkm) are multiplied by the expansion constant and the global security factor (SF) to give an initial transport tariff. These initial transport tariffs are multiplied by the expected total metered triad demand and total generation TEC capacity (MW) to calculate the initial revenue recovery. These initial revenue recoveries are then corrected to obtain a 27:73 split in revenue collection between generation and demand respectively. This is achieved through the calculation of a single constant, C, which is then added to the total zonal marginal km for generation and demand as below;

$$\sum_{Gi=1}^{21}\left[\left(ZMkm_{Gi}+C\right)\times EC\times SF\times G_{Gi}\right]=CTRR_{G}$$

$$\sum_{Di=1}^{14}\left[\left(ZMkm_{Di}-C\right)\times EC\times LSF\times D_{Di}\right]=CTRR_{D}$$

Where EC = expansion constant
LSF = locational security factor
G = generation within [a] [each]zone
D = demand within [a] [each]zone
CTTR = 'generation / demand split' corrected transport revenue recovery

In addition to the existing re-referencing process ensuring the correct revenue split, the introduction of the C constant also ensures that the transmission charging methodology is stable for any changes to the reference node[37]. Effectively, the C constant readjusts for the position of the reference node when ensuring the 27:73 (G:D) revenue recovery split.

However, the (National Grid) proposal makes this referencing process more involved due to the following features;

[37] The reference node is required to ensure balancing of the incremental MW DC load flow analysis in the Transport model.

- *Determination of triggering criterion* – Alteration of the reference node in the Transport model will alter circuit flows in the two background models, and therefore the determination of circuits as either year round or peak security. This will have the impact of altering the total revenue collected through each locational charge.
- *Difference in generation charging base* – Re-referencing of generation tariffs to alter specific revenue recoveries could mean that some revenue collection is transferred between locational charges and the residual. As these have differing generation charging bases, charges could be re-apportioned on an unequal basis.

In order to resolve these issues there are several options available. These are summarised below, with option 1 being the method presently preferred by National Grid for re-referencing on the basis that this is consistent with the current approach.

- *Option 1 - Re-reference each locational revenue element separately for the G:D revenue split:* Peak security and year round revenue pots are separately re-referenced to obtain a 27:73 split for each pot, without altering the size of the pot. This effectively works by creating two C constants; one for each triggering criterion. This is currently the preferred mechanism. Whilst this accounts for differences in generation charging bases, it does not fully resolve the issues with the reference node. In order that this is resolved, it is proposed to introduce a distributed reference node.

- *Option 2 - Re-reference by revenue recovery:* Each set of wider locational tariffs are separately re-referenced to ensure the overall revenue recovery from each criteria is zero. This has the benefit of maintaining consistency of the size of each revenue pot (i.e. zero), and also makes the solution stable for reference node changes. However, charges are redistributed through the re-referencing process as, when creating the residual charge, charges are moved between different generation bases.

A3.1.2.1.2.5 Relevant Chargeable Capacities for Generator Charge Calculations

It is proposed (by National Grid) that, for the peak security criterion, there is no change to the existing definitions of chargeable capacity. Hence, the chargeable capacity for power stations with a positive wider peak security tariff will be the highest TEC (MW) applicable to that power station for that Financial Year. The chargeable capacity for power stations with negative wider generation tariffs would continue to be the average of the capped metered volumes during three settlement periods of the highest and next highest metered volumes which are separated from each other by at least 10 Clear Days, between November and February of the relevant Financial Year inclusive. These settlement periods do not have to coincide with the demand Triad.

It is proposed that, for the year round criterion, the chargeable capacity for all power stations would be based on the highest TEC (MW) applicable to that power station for the Financial Year. This is correct for the year round criterion, as the load factor used in tariff calculation has been calculated on the TEC (MW) of the power station rather than its highest output during the winter period.

A3.1.2.1.3 The Residual Tariff

As with the existing process there is still a requirement under this National Grid proposal for a residual charge in order to ensure the necessary revenue recovery.

Assuming that the revenue to be collected from generator users is 27% of total infrastructure revenue, the required revenue to be recovered from the generation residual charge can be calculated as;

$$R_{RG} = 0.27T_{tot} – R_{LS} – R_{LC} – R_{PSG} –R_{YRG}$$

Where; R_{RG} = required revenue from generation residual charge
T_{tot} = total infrastructure revenue
R_{LS} = revenue from local substation charges
R_{LC} = revenue from local circuit charges
R_{PSG} = revenue from peak security locational charges
R_{YRG} = revenue from year round locational charges

The £/kW residual charge can then be calculated from the division of this required revenue by the chargeable generation capacity which, for the residual charge, is proposed to be equal to the total GB Transmission Entry Capacity (TEC) of connected generation. The residual calculation for demand is shown below.

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A3.1.2.1.4 Small Generators Discount

Although not directly part of the TNUoS methodology, these proposals have a potential impact on National Grid's Transmission Licence Condition C13 which ensures small generators connected to the 132kV transmission system are eligible for a reduction in the listed generation TNUoS tariffs. Currently the discount equates to 25% of the combined generation and demand residual components of the TNUoS tariffs. It is not proposed to alter this level of discount. However, an alternative approach could potentially be to apportion this (25%) discount to generators based on their annual load factor.

A3.1.2.2 Demand Charges

It is not proposed to alter the overall nature of TNUoS demand charges and the structure relating to half hourly (HH) metered customers and non-half hourly (NHH) metered customers would not be altered. The zonal charging structure would remain aligned with the 14 GB DNO boundaries as now. It is proposed that the structure of final TNUoS tariffs remain unaltered, with a zonal £/kW tariff for HH customers and a zonal p/kWh tariff for NHH customers.

However, in order to reflect the introduction of the year round and peak security background criteria, there would need to be modifications to the tariff calculation methodology. This is in order to facilitate a 73% share of revenue recovery from each locational component. As for generation users, it is proposed that zonal MWkm will be tagged by their triggering criterion (i.e. equal and opposite to generation on a nodal basis), and through multiplication by the expansion constant and global security factor, unadjusted zonal tariffs for year round and peak security. These would then be separately re-referenced to ensure 73% revenue collections for each criterion. The required revenue to be collected through the demand residual would be derived from the following formula;

$$R_{RD} = 0.73T_{tot} – R_{PSD} –R_{YRD}$$

Where; R_{RD} = required revenue from demand residual charge
T_{tot} = total infrastructure revenue

R_{PSD} = revenue from peak security locational charges
R_{YRD} = revenue from year round locational charges

Zonal £/kW tariffs for HH customers and zonal p/kWh tariffs for NHH customers would then be calculated as per the existing transmission charging methodology.

A3.1.3 Proposed Annual Load Factor (ALF) Methodology

National Grid's proposal recommends that a suitable proxy for the year round effect that a generator has on transmission system investment is that each generator's forecast annual load factor is based on the average of its historical output over the last five financial years, with the highest and lowest years excluded from the calculation of ALF to remove the majority of atypical behaviours and running regimes. The forecast ALF would be used to scale a generator's year round wider locational TNUoS charge; i.e. the charge based on its year round operation.

The ALF is taken to be indicative of assumptions made about a generator's operating regime in transmission planning timescales, and therefore its effect on transmission investment required for year round operation of the system. As such it is not intended to be an accurate reflection of a generators actual output over a particular twelve month charging period. Whilst several potential options exist for the calculation of the ALF based on forecast or historical load factor, this proposal puts forward a fixed, historical based approach that precludes the need for an end of year reconciliation. The benefits of this fixed approach are added certainty and stability as a result of increased predictability of tariffs and accuracy of within year revenue collection. In addition, of all the alternatives considered, this approach is deemed most representative of assumptions made in transmission network planning timescales.

A3.1.3.1 Calculation of User Specific ALF

Historic annual load factors would be calculated (for each power station) for each of the last five complete financial years (years -5 to -1) (with the highest and lowest load factors removed) using the formula below;

$$ALF = \frac{MWhr_{\_Output}}{TEC * 8760}$$

The TEC figure used in each calculation would be the highest TEC applicable to that power station for that financial year. The MWh output figure would be derived from published historic user data available to National Grid. Alternative sources for this data could include Final Physical Notification (FPN) and metering data used for settlements purposes. The benefit of FPN data is that it better represents a generator's intended system usage as it accounts for some SO constraint actions taken to manage the system. However, it should be noted that longer timescale SO actions would not be captured. The use of FPN data may also require the development of a new process to obtain validated historic FPN data, as this data is not currently used for settlement purposes for all users.

For an April 2012 implementation it is proposed that metered data would be used to calculate tariffs on the basis that the approach of removing the highest and lowest load factors from the ALF calculation would remove the majority of atypical behaviours and running regimes. It may be necessary for National Grid to undertake a review of FPNs vs. metered data in the first year to check for any anomalies of a material nature.

Once all five historic load factor figures have been calculated they would be compared, and the highest and lowest figures are discarded. The discarding of these outermost figures ensures that the final ALF is representative of an indicative operating regime for a particular generator, and has not been influenced by atypical behaviours. Such behaviours can range from unseasonal weather conditions through to response to System Operator instructions.

The ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three historic load factor figures. The process, with example figures, is illustrated in Figure III below.

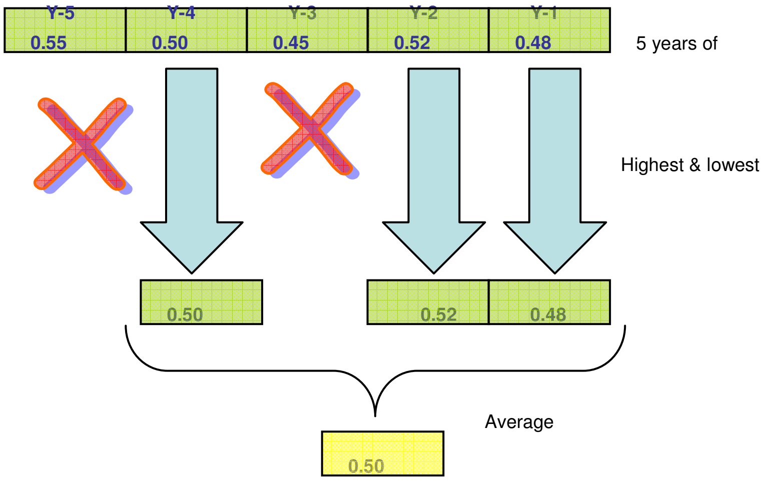


Figure III – Process for deriving user specific ALF

In the event that only four years of complete metered data are available for a generator then the higher three years load factor would be used in the calculation of ALF. In the event that only three years of complete metering data are available then these three years would be used.

Due to the aggregation of metered data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the annual load factor would be calculated based on the total output of the BMU and the overall TEC of the BMU.

A3.1.3.2 Derivation of generic generator data

In the event that there are not three full years of a generator's output available, missing historical information would be replaced by generic data for that generator type to ensure three years of information are available for the user.

Generic data would be derived from the average annual output of all GB generation of a particular fuel type over the last five years, using an identical methodology to that used for the user specific calculation. The proposed fuel type categories and illustrative data are listed in Table IV below;

Fuel Type	Generic Load Factor
Biomass	N/A
Coal	43%
Gas	57%
Hydro	12%
Nuclear	60%
Oil	2%
Pumped Storage	15%
Wind	16%

Table IV – Fuel Type Categories to be used to derive generic load factor

For new and emerging technologies, where insufficient data is present to allow a generic load factor to be developed from historic information, a generic load factor would be produced by National Grid using its agreed forecast modelling tool. Currently, it is anticipated that this would be either Plexos or the Electricity Scenario Illustrator developed by National Grid for RIIO-T1 engagement.

Generic load factors would be reviewed annually in the period November – December (i.e. at the same time as user specific ALFs) and would be published, in a form similar to Table IV above, within the Statement of Use of System Charges (the Charging Statement).

It should be noted that for new generation connecting mid-year, a pro-rated ALF would be derived using the figures in Table IV. When used for this purpose, it is assumed that the output of the generator is apportioned evenly across a twelve month period.

A3.1.3.3 Proposed Timeline

ALF forecasts would be provided to all generation users at the same time as draft TNUoS tariffs are published. The full proposed timeline is described below.

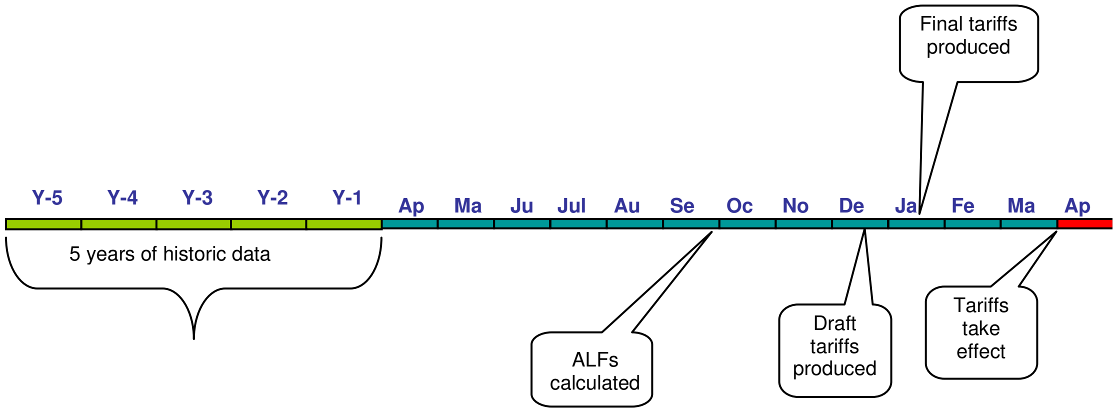


Figure IV – Timeline for proposed process

A3.2 National Grid Analysis of the Impact on Generator Load Factor on Constraint Costs

The GB electricity transmission system is developed on an economic basis to ensure the lowest overall cost to the end consumer. On a broad level these costs can be realised in one of two ways; either as the cost of capital investment, incurred through the construction of new transmission system capacity (long run costs), or as the cost of operating the system, incurred through the day to day costs of balancing flows across the transmission system (short run costs).

One of these key balancing services is the requirement to manage constraints on the transmission network. System constraints occur when, without System Operator intervention, power flows on the transmission network would exceed operational limits on the system. If these operational limits are frequently exceeded, or if the cost of their management by the SO is sufficiently high, then it may be more efficient to permanently raise the limit through reinforcement of the transmission system. There is therefore a linkage between the marginal short run costs of operating the system and the long run costs of transmission investment. Ultimately it is the responsibility of the System Operator and Transmission Owners to ensure that efficient transmission system development balances both these costs.

The amount of power a generator produces over a period of time, quoted as a proportion of the maximum amount of power it could produce during that period, is referred to as the generator's load factor. It follows that a generator with a high load factor, who generates at a higher level, or more often, than a lower load factor generator will have a larger impact on the transmission system. This is because, during periods of system constraint, it is more likely to be operating and potentially adding to the constraint. Whilst logically a relationship can be appreciated, it does not mean that the relationship is of a linear nature, nor indeed that it is a significant factor in constraint costs at all.

In order to better understand the relationship between generator load factor and constraint costs, analysis has been undertaken by National Grid using an economic model of the electricity market and transmission network. The model used being the CBA cost benefit analysis model developed for the NETS SQSS intermittency proposals.

The model works by investigating the effect on constraints of an incremental increase of 1 MW of a specific generation fuel type assessed against the overall change in GB constraint costs across a year of operation. The NETS SQSS model utilises transmission zones built around planning transmission boundaries. The model was assessed using the 2011/12 'Gone Green' backgrounds developed by National Grid.

The effect of the incremental 1 MW is considered across a number of background runs representative of a year of operation of the transmission system. . In some of the runs the incremental 1 MW will be generating, in others it will not due to the relative requirements for power. Overall, when considering all runs of the model, this will give an annual load factor for that generator, which will be different for different fuel types. This is shown graphically on the x-axis of the results graphs, with a typical graph being given in the Figure V below. This is effectively the annual load factor of the incremental 1 MW. The y-axis of the graph in Figure V represents the affect on GB constraint costs for this incremental MW as compared to a base run.

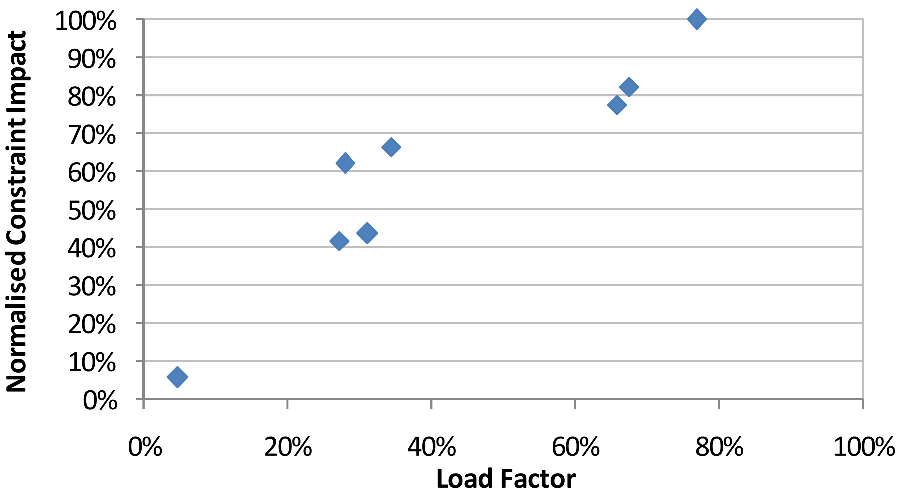


Figure V – Illustrative Output

Results from the model are included latter in this Annex. National Grid believes that generally there is a good correlation as to the relationship between generation load factor and constraint costs, and in the majority of cases this relationship is found to be broadly linear in nature. This suggests that the relationship is maintained, regardless of a generator's specific fuel type.

There are some limitations to this relationship. It can often be seen that wind generation causes a comparatively higher change in constraints than other fuel types. Also, in locations where there is a dominance of a particular fuel type, the relationship for that fuel type can be skewed from the norm.

In conclusion, whilst accepting some limitations, analysis of the model suggests a relationship between a generator's output during a year of operation (i.e. its load factor) and the level of constraint costs incurred. This relationship exists irrespective of the generator technology. Accepting the linkage between constraint costs (short run marginal costs) and transmission investment costs (long run marginal costs), National Grid believes that it appears logical to consider generator load factor as a reasonable and simple proxy for economic transmission investment requirements.

It is necessary, when considering whether the use of a generation load factor in transmission charging is an improvement on the cost-reflectivity of the current approach, to consider how the relationship between a generator's load factor and constraints compares to that of a generator's capacity (TEC) and constraints. Figure VI, below, compares the correlation between generation load factor and constraints with the correlation between capacity (TEC) and constraints using an example of actual output from the model (in Zone 2). A 'least squares fit' trend line (in red) is used to represent the correlation of generation load factor to constraints, whereas a straight average (in green) is used as a proxy for the correlation of capacity (TEC) and constraints (i.e. a perfect correlation between capacity and constraints would be a straight line with a slope of zero).

By visual inspection of the proximity of model outputs (plotted in blue) to the two comparison indicators (in red and green), National Grid believes it is clear that load factor is a better indicator of the impact on network investment requirements than a generators capacity, as is currently used.

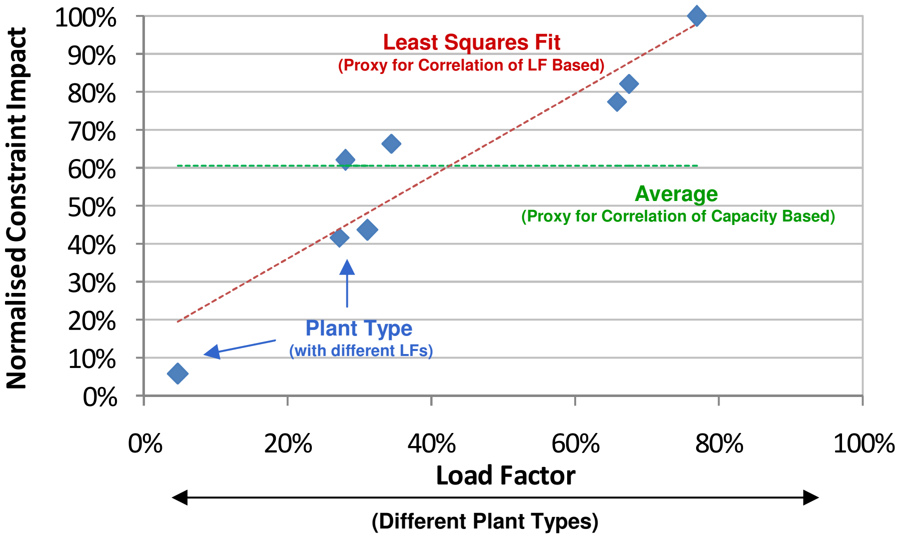


Figure VI – Comparison of LF and Capacity Correlation to Constraint Impact

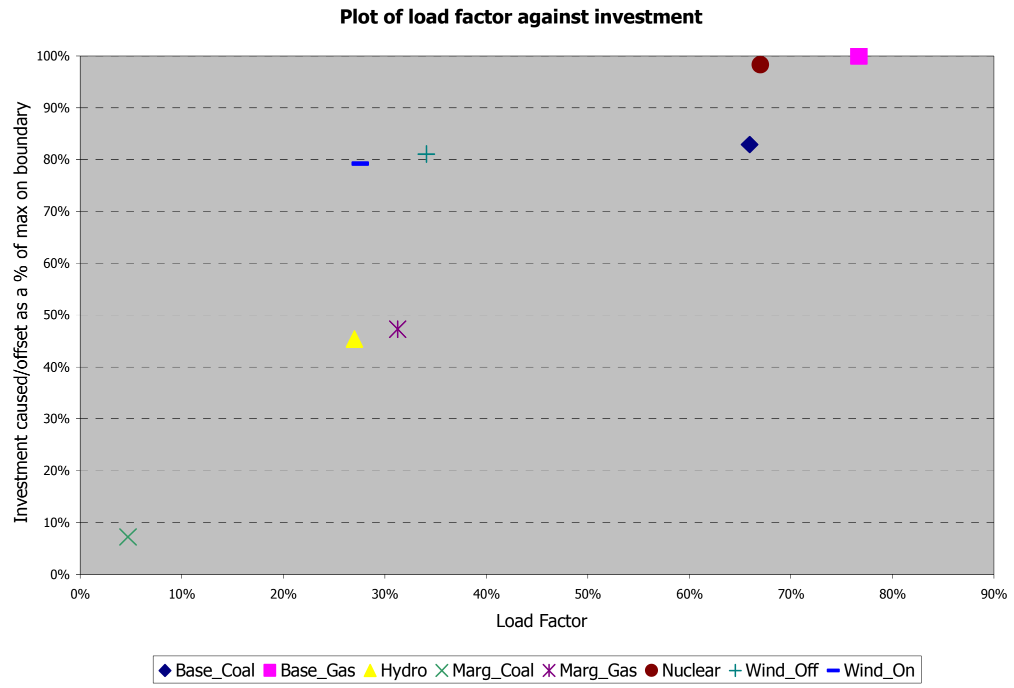
This comparison was carried out for each transmission zone and presented to the Working Group[38].

A3.2.1 Results from NETS SQSS CBA Model

All results shown below are from the 2011/12 ‘Gone Green’ scenario. Analysis was carried out through application of incremental 1MW to this background and assessment of the impact on GB transmission system constraint costs. A full set of results was obtained through application of 1MW on zonal and generation type bases. Note generation effects are only given for generation types that exist within a zone.

[38] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/IS%20-%20Updated%20Load%20Factor%20slides.pdf

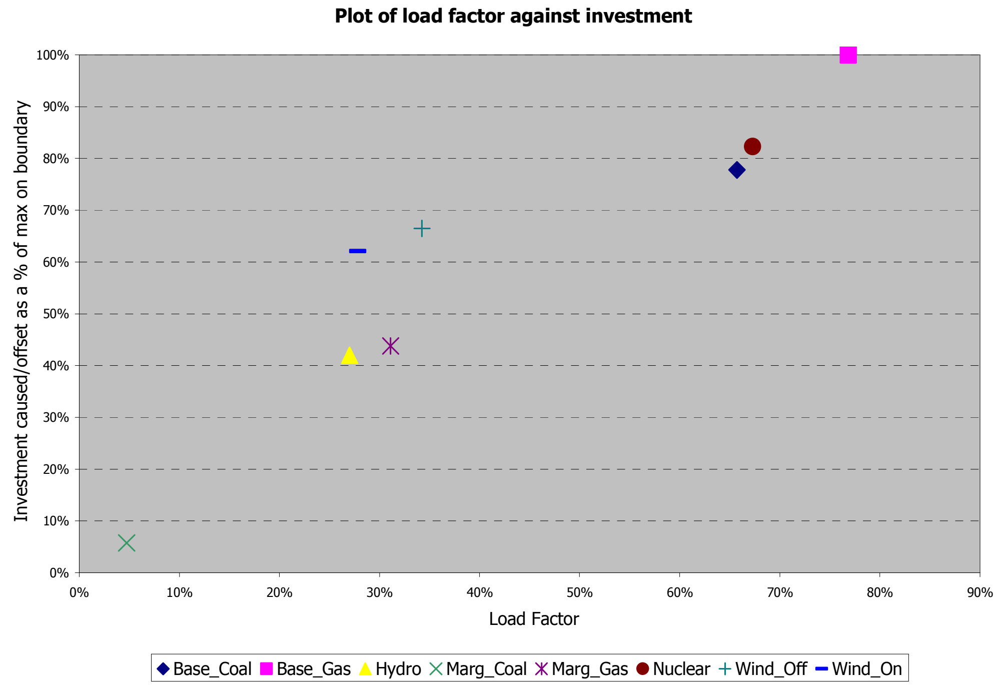
Zone 0 – NW SHETL



High level summary

- There is an observable correlation between generation load factor and transmission constraints incurred for the majority of generation types.
- Off-shore and on-shore wind give rise to higher levels of constraints in relation to their load factor.

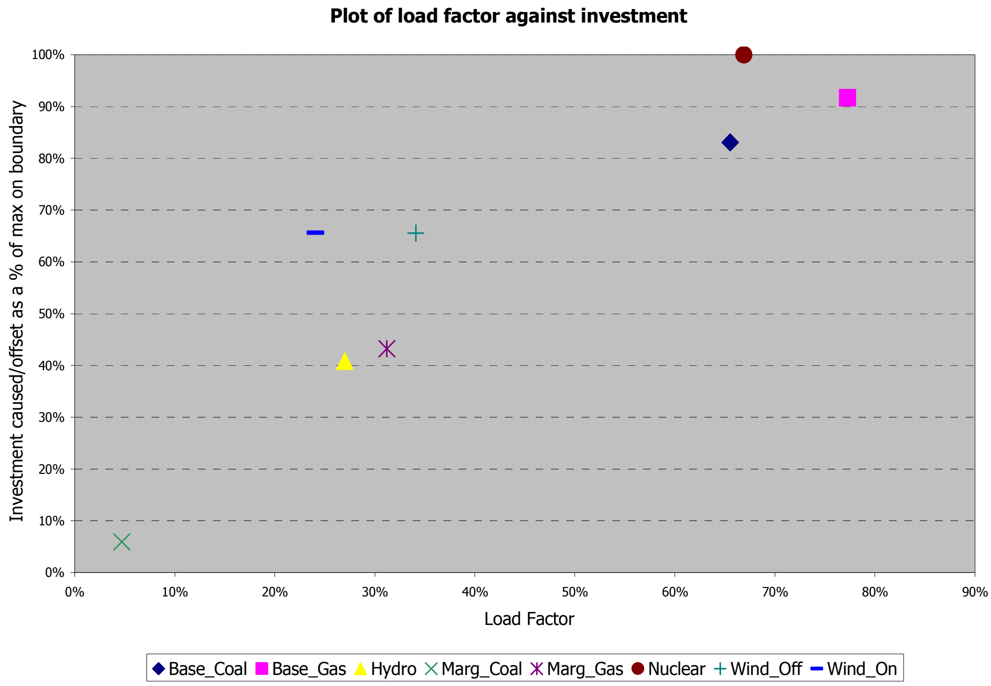
Zone 1 – SHETL



High level summary;

- Discernable link between generation load factor and transmission constraints incurred.
- Off-shore and on-shore wind still away from trend, but closer than zone 1.

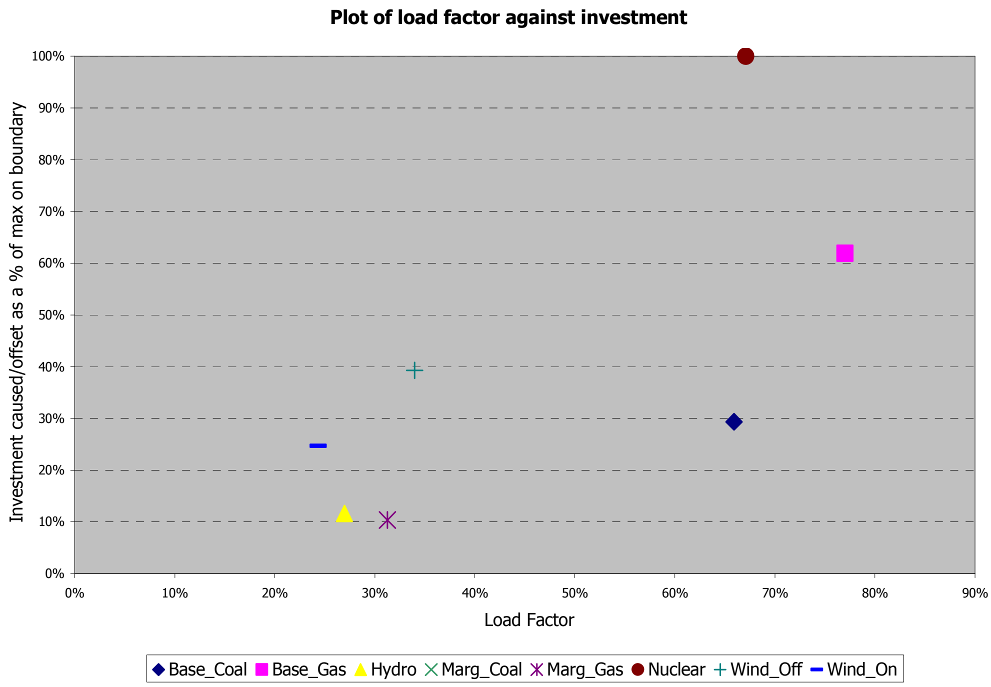
Zone 2 – SPT



High level summary;

- Correlation still visible, though not as apparent as zone 1.
- Off-shore and on-shore wind still above trend.
- Nuclear also risen above trend (this is most northerly zone with nuclear generation).

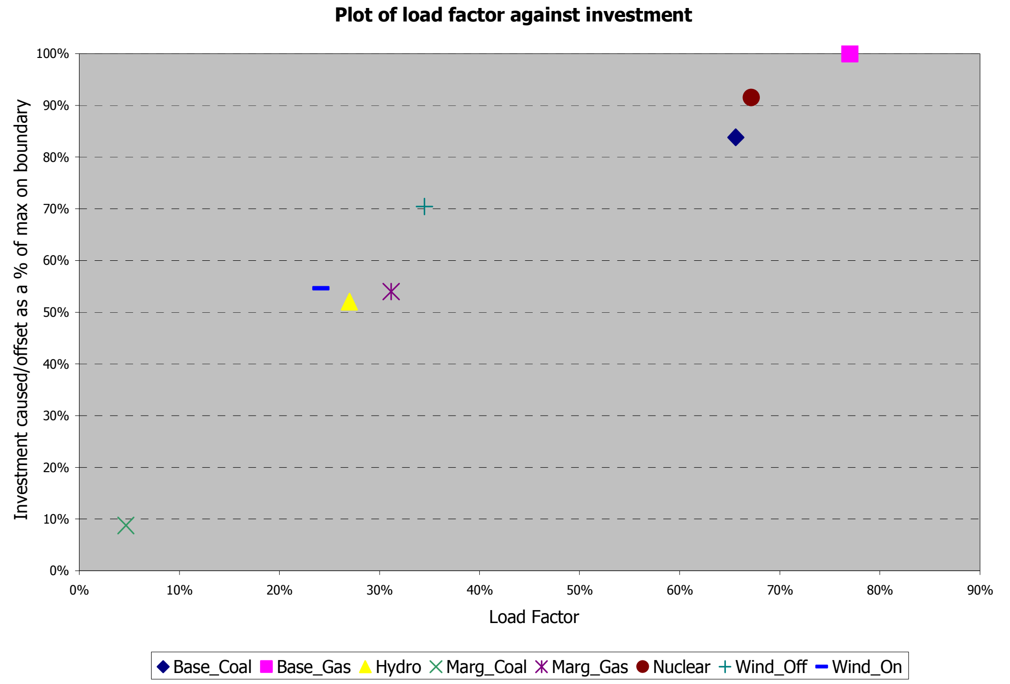
Zone 3 – Upper Northern England



High level summary

- Less discernable pattern, with almost two separate lines;
    - Upper line – Off-shore wind, on-shore wind, nuclear
    - Lower line – Rest

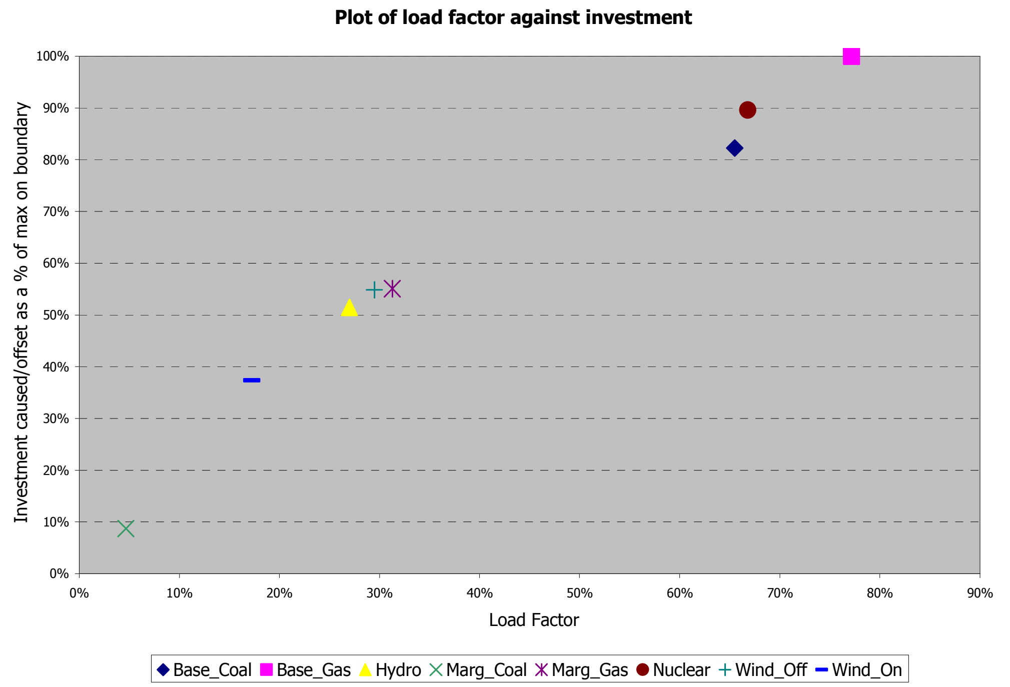
Zone 4 – Northern England



High level summary

- Good correlation for all generation types between transmission constraint change and generation load factor.
- NB - MW increment of each generation type reduces transmission constraints under CBA model.

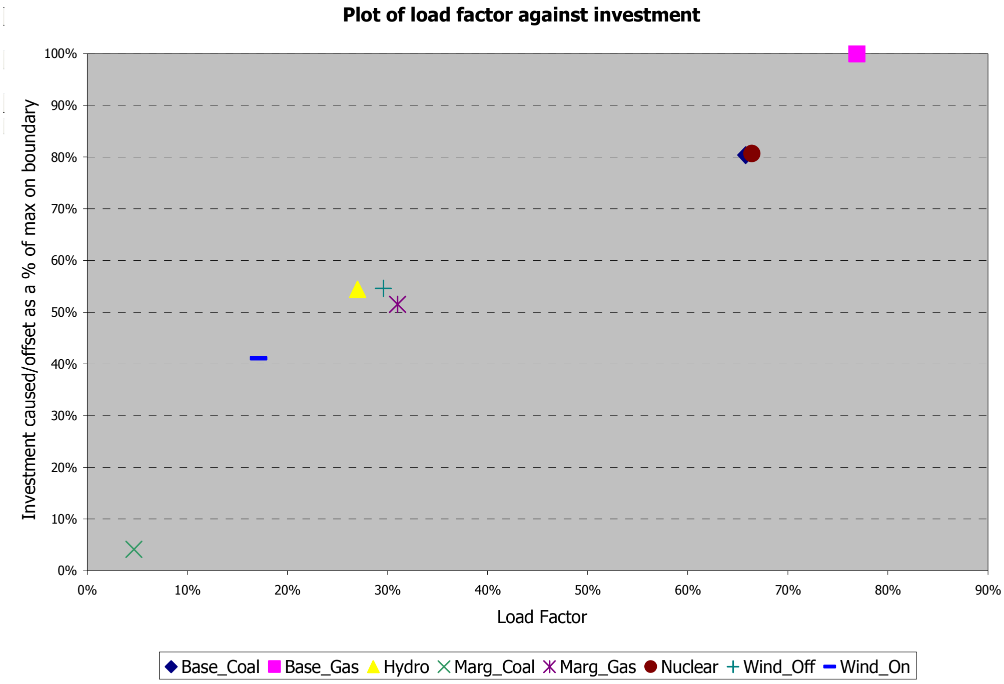
Zone 5 – Midlands



High Level Summary

- Strong correlation between generation load factor and change in transmission constraints.
- NB - Increase in any generation in this zone reduces GB transmission constraints in model.

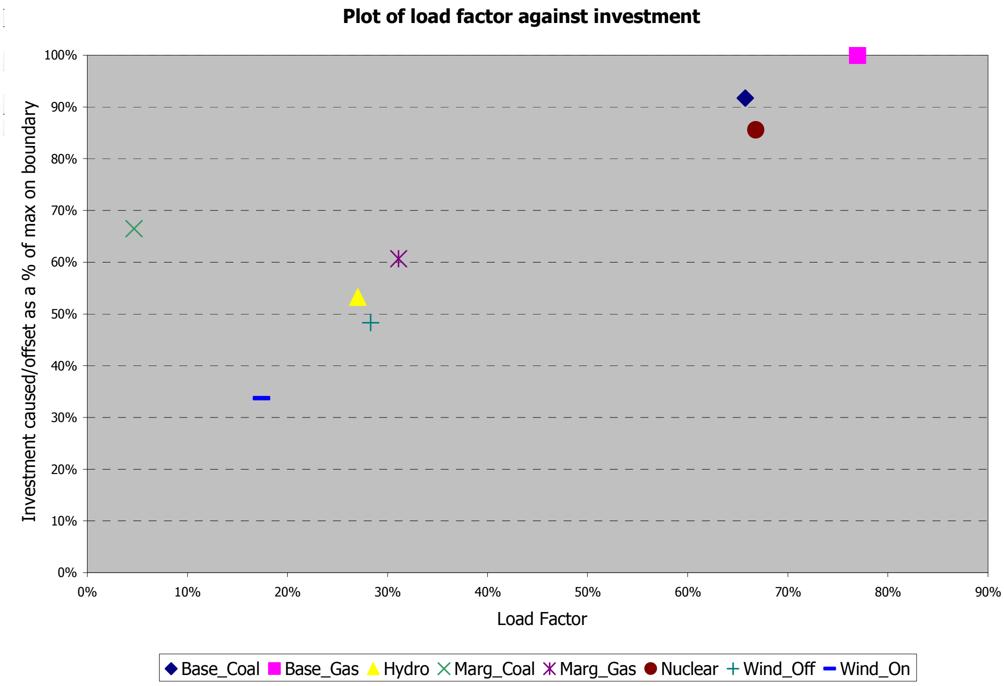
Zone 6 – Thames Estuary



High Level Summary

- Overall trend still observable.
- NB - Increasing most generation within zone reduces transmission constraints - exception is marginal coal which was found to slightly increase constraints.

Zone 7 – Southern England



High level summary

- Strong trend observable in results.
- NB - Increase of any generation type within zone reduces GB transmission constraints.

A3.3 Summary of Comments in Respect of National Grid Theme 1 Proposal

The following Q&A section is a modified version of a paper circulated to the Working Group by National Grid in order to answer the questions raised within the group in respect of National Grid's proposal for Theme 1 - Reflecting characteristics of transmission users.

<u>The answers included in this section are National Grid's view and may not represent the view of the Working Group.</u>

Q) *Fixed annual transmission charges are for a right of access up to a maximum capacity based export limit (TEC). Might a scaled charge imply a different type of access?*

A) The National Grid proposal does not seek to change users' transmission access rights, with generators continuing to have firm transmission access rights in accordance with their Transmission Entry Capacity. The implicit assumption of transmission network capacity sharing by generators of different characteristics is reflective of the assumptions made in the network capacity investment decision.

Q) *National Grid analysis implying a direct relationship between ALF and constraints and therefore transmission tariffs warrants more rigorous justification before this premise can be used.*

A) Further details of the National Grid analysis was provided in annexes 1 and 2 of the revised Theme 1 proposal document circulated to the group (a section of which is included in Section 2 of this Annex, above). It is recognised that generator load factor is not the only generation characteristic that contributes to network operational costs (and hence transmission network investment costs in a cost-benefit approach to network planning). However, the relatively linear relationship between generation load factor and transmission constraint costs demonstrated through analysis is believed to represent a reasonable balance between simplicity, stability and cost-reflectivity.

Q) *Any interaction is strongly linked to the diversity of generation behind any given boundary*

A) It is noted that the diversity of generation behind a given transmission boundary can have an impact on constraints. However, inclusion of diversity considerations would increase the complexity of the proposal. Analysis has indicated that generator load factor alone represents a reasonable proxy across the GB transmission system for at least the next five years when using the "Gone Green" background assumptions. In addition, load factor has been shown to be better indication of impact on transmission network costs than capacity (i.e TEC).

Charging and the NETS SQSS

Q) *Why has the link to NETS SQSS been broken?*

A) The existing NETS SQSS[39] requires the Transmission System Operators to consider in the design of the main interconnected transmission system not only the requirements for transmission system peak, but also the year round use of the transmission system including cost-benefit analysis development of the

[39] [39] NETS SQSS v.2.1 7th March 2011; http://www.nationalgrid.com/NR/rdonlyres/784F2DFC-133A-41CD-A624-952EF4CCD29B/45776/NETSSQSS_v21_March2011.pdf

transmission network (see Appendix E of the NETS SQSS – "Guidance on Economic Justification"). Due to the changing generation mix, not least of which is due to the increasing penetration of intermittent generation, this second requirement is becoming increasingly significant. Hence National Grid would disagree with the above statement, in that the Theme 1 proposals are still in alignment with the existing NETS SQSS, to the extent that this alignment has historically existed.

Q) *Clarity is needed on the overall position in respect of cost reflectivity of transmission assets and what assets are built according to transmission planning standards*

A) Transmission companies in Great Britain have a license obligation to plan and operate their networks in accordance with the NETS SQSS. All transmission assets are therefore 'built according to transmission planning standards'.

Q) *Strawman proposal is based on GSR009 (yet to be approved)*

A) The National Grid proposal builds on the analysis undertaken by the GSR009 review group to understand how a complex cost-benefit analysis can be approximated to a single model of background conditions. For clarity, this group consisted of representatives from NGET, SHETL and SPT. The original analysis has already been presented to industry for comment[40], and modified as a result[41]. This work stands, in its own right, as representative of a full CBA which is already a requirement of the existing NETS SQSS document. Therefore, National Grid believes that it is largely immaterial as to the status of proposed NETS SQSS changes when considering a cost-reflective TNUoS charging proposal.

Q) *Strawman implies that the SQSS process will continue to govern the process of transmission charging*

A) The National Grid proposal presents an option for an incremental improvement to the ICRP methodology, specifically to address 'Theme 1' under the SCR. As such, we National Grid have assumed that paragraphs 14.14.6 and 14.14.7 of Section 14 of the CUSC would continue to apply.[42] It is believed that the Theme 1 National Grid proposal is more reflective of the incremental impact that Users of the transmission system at different locations (and of different characteristics) would have on the Transmission Owner's costs.

Q) *Subsequent comment from NGET seems potentially contradictory: "National Grid does not believe that a direct link between deterministic criteria set out in the NETS SQSS and the charging methodology necessarily needs to exist in order for charging to be cost reflective"*

A) Whilst National Grid have assumed that the linkage between TNUoS charging and the NETS SQSS will remain, National Grid does not believe that there necessarily needs to be (or has historically been) a 'hard wired' connection linkage between the detailed application of the two for transmission charges to

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[40] NETS SQSS Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation – GSR009 Consultation Document v1.0 11th June 2010; http://www.nationalgrid.com/NR/rdonlyres/E22B1547-D4CC-4F88-AEEF-C76305718C25/41720/GSR009SQSSConsultation.pdf

[41] Minimum transmission capacity requirements in the Security and Quality of Supply Standard 12th August 2011; http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/SQSS/Documents1/GSR009%20Impact%20Assessment.pdf

[42] CUSC, section 14, v1.2; http://www.nationalgrid.com/NR/rdonlyres/8FFA9408-9DC7-44C2-AF68-93E684A176D8/47549/CUSC_Section_14combinedmasterclean5July11_FINAL.pdf

be cost reflective. The complexities of transmission network planning have always required simplification when reflected in transmission charging arrangements for reasons of transparency, stability and practicality. This will remain the case under the proposal for Theme 1.

The Dual Background Approach

Q) *For the dual background approach; what are the drivers for transmission investment and are these used appropriately to deliver cost reflectivity?*

A) Transmission investment is driven by the design standards laid out in the NETS SQSS. Section 4 specifically covers requirements for the design of the main interconnected transmission system, and requires consideration of both the average cold spell (ACS) peak demand conditions, and conditions in the course of a year of operation. National Grid is building on the analysis undertaken by the NETS SQSS review group under GSR009 to use two backgrounds within the ICRP methodology to reflect these two conditions. Transmission circuit flows under each background will be compared to ascertain the higher flow, and this background will be considered to be the case which would cause the need for transmission reinforcement. This is consistent with the underlying rationale behind TNUoS charges; that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them.

Q) *Why only recover a 'flat' peak capacity charge from a subset of generators?*

A) National Grid's proposal is based on the analysis undertaken by the GSR009 review group which recommended an intermittent output of zero for peak demand analysis. A flat charge is consistent with the current approach to peak charging and a subset of generators is deemed not to contribute to the need for additional transmission network capacity under ACS peak demand conditions.

Q) *Could an end of year reconciliation be used to charge intermittent generation for their use of peak?*

A) An end of year reconciliation could be used to charge intermittent generation, as could alternative options such as an intermittent charge based on historical output at peak. However, this could be deemed less reflective of the incremental costs of supplying transmission network capacity to these generators under ACS peak demand conditions, where their output is assumed to be zero.

Q) *Given that economic transmission system reinforcements are increasingly made for renewable generation are the costs of the two scenarios appropriately attributed?*

A) The relative costs of the two scenarios are derived from the apportionment of transmission circuits to each scenario, based on the scenario giving the higher flow. This is consistent with the view that the higher flow would trigger the need for transmission system reinforcement earlier and, as such, consistent with the principle of reflecting the incremental cost of supplying network capacity to a User at a given location.

Q) *A different methodology for tagging of circuits might be more appropriate given the philosophy of ICRP? It would demonstrate that any increase in flow triggers some level of reinforcement.*

A) An alternative option for the tagging of transmission circuits was put forward by a Working Group member. National Grid undertook analysis of this approach, and presented results in Annex 4 of their Theme 1 report, which was circulated to the group. Whilst not dismissed as a feasible approach, it is believed to be less cost-reflective than the initial National Grid proposal. This is supported by the fact that both approaches lead to a similar level of total transmission network incremental MWkm (i.e. consistent with the principle that any increase in flow triggers some level of transmission reinforcement).

Load factor usage and calculations

Q) *Can you explain further the justification for a fixed % in the background setting and an individual LF being applied to tariffs?*

A) The fixed percentages in the background setting for the year round criteria relate to the analysis undertaken by the SQSS GSR009 review group in the derivation of a single background that could be used to best represent the overall impact of power flows for year round operation of the GB transmission system. Whilst these fixed percentages lead to power flows that result in a reasonable proxy for economic investment in transmission network capacity, they are only deemed suitable for the tagging of transmission circuits as either being peak security or year round driven in the charging methodology. It is recognised that individual users, within the same generation class, will have a different impact on transmission investment requirements based on their specific assumed output over a period of time at the time of making the network investment decision. This is why National Grid are is proposing to use individual generator load factors in transmission charge calculations.

Q) *Given that the rationale for use of Annual Load Factor (ALF) has yet to be fully justified we should use a set of tariff equations which exclude this aspect, in parallel with the current proposal.*

A) Whilst National Grid believe that a robust justification for the use of ALF has been put forward, National Grid encouraged Working Group members to put forward any alternative options that they believe to present a better balance between simplicity and cost-reflectivity. National Grid would question whether this particular alternative could be considered as cost reflective for users as the current National Grid proposal (see Figure VI in Section 2 of this Annex). It is important that any alternatives put forward are justified on the basis of the transmission charging objectives set out in the CUSC and the Transmission Licence.

Q) *What is the justification for applying to the wider element only?*

A) Local circuit and substation elements reflect transmission build made for a specific user (or users), which therefore limit the potential for sharing of transmission network capacity and, as such, are sized to that user's (or users) capacity. Design variation (a.k.a. 'user choice') is available on local circuits and as such the transmission charge for these network elements should reflect the full cost of the build rather than an amount based on its usage.

Q) *Load factor might be better based on FPNs than metered output?*

A) National Grid is currently analysing both FPN and metered data to quantify the level of difference. However, it should be noted that even FPN data would not capture all relevant running hours (e.g. additional running hours caused through SO instruction) that an annual load factor (ALF) calculation should incorporate. There are pros and cons to the use of both these data sources and National Grid is currently proposing to use metered data for simplicity, subject to the outcome of the aforementioned analysis.

Q) *What is the rationale for a 5 year period given the likely changes to plant running due to a changing generation mix?*

A) The rationale for a five year period is to ensure that variability such as seasonal difference or unit breakdowns are smoothed out as much as possible. However, it is noted that this smoothing needs to be balanced against changes to users' planned operating regimes. As with many transmission charging issues, the choice in respect of calculated ALF comes down to the balance between stability and cost-reflectivity. The assumptions made by the transmission planner, which do not reflect actual generation operating regimes, are relevant in this respect.

Assumed Contribution at Peak

Q) *It seems perverse that generators which secure the transmission system are to see a higher share of network costs?*

A) There is an ongoing requirement to ensure that there is sufficient transmission network capacity to ensure that generation output at (ACS) system peak can be accommodated. National Grid's proposal seeks to ensure that the incremental cost of this transmission network investment requirement is charged appropriately. Commensurate with this approach, the peak security element of the TNUoS tariff will be positive in some zones and negative in others. It seems reasonable to continue on the premise that TNUoS charges signal the cost of transmission network investment only and therefore need not compensate generators for energy supplied at peak or any other time of year.

Q) *Are there implications for the capacity mechanism of these assumptions around contribution to peak and contribution to transmission system costs*?

A) National Grid's proposal seeks to reflect the costs of transmission investment in TNUoS (i.e. transmission owner costs). Whilst accepting that there may be an interaction with the UK Government's proposed introduction of a capacity mechanism, which considers the role of the system operator going forwards, National Grid would suggest that this sits outs outside the remit of the Project TransmiT SCR.

Detailed Aspects

Q) *Why is the re-referencing step required on the wider locational tariffs before applying the G/D split?*

A) Re-referencing takes place in the Tariff Model to ensure that the correct ratio of revenue is collected from generation and demand through both the un-adjusted (i.e. purely locational) and adjusted (i.e. locational + residual) steps of the tariff setting process. Under the status quo this step is somewhat redundant. However, with a two part (peak security and year round) tariff charged differently to different generation types this step becomes important to apportion revenue to these elements in a consistent manner.

Q) *Why not remove negative charges?*

A) Generation charges could be re-referenced such that all transmission charges were positive, but differentials kept the same. This would affect the balance of revenue collection between locational charges and residual which, given the National Grid proposal's different generation charging bases, may lead to concerns over re-distribution of costs using this methodology.

Q) *Price control length and review timescales – how often will parameters be updated?*

A) Whilst this depends on the particular parameter, (e.g. generator load factor inputs to the ALF calculation should be updated annually) National Grid would note that there needs to be a balance struck between stability of transmission charges and the need for charges to reflect changing external factors. Whilst National Grid have suggested the link between reviews and transmission price control periods, as this is largely in alignment with the current methodology, alternative proposals with an associated justification were welcomed.

Q) *Plant classifications by fuel type/ new technologies i.e. how to treat those running on gas oil?*

A) National Grid is proposing that power stations with more than one fuel technology are treated by the dominant fuel technology, but would welcome alternative, justifiable proposals to this approach.

Background

Theme 4 is concerned with how to incorporate technologies not currently used on the transmission network in Great Britain into the transmission charging methodology.

This note considers how to treat high voltage direct current (HVDC) 'bootstraps'; i.e. HVDC links; that are connected in parallel with the main AC transmission system. It does not deal with "interconnected HVDC networks" of the form that may evolve offshore nor does it deal with other types of new technology such as series capacitors. It is based on the note presented by a Working Group member on 5th August 2011 and the National Grid presentation given to the Working Group on the 9th August 2011. The HVDC links considered are those of the types that are currently envisaged for reinforcing the connection between Scotland and England and Wales with undersea HVDC cables running off the east and west coasts of Great Britain.

The description is probably only adaptable to a locationally differentiated transmission charging methodology for example the current Status Quo methodology or Improved ICRP rather than the postalised approach. It is considered that although it is new it would still be applicable to the Status Quo option as it is driven by a new type of technology rather than a new transmission charging methodology per se and therefore even for the Status Quo transmission charging option a development of the existing rules would be needed to deal with the new technology.

The rest of the note is structured as:

- Why the existing methodology does not work for HVDC 'bootstraps' bootstraps
- Options for treating HVDC 'bootstraps' where they cross a single main transmission boundary
- The additional methodology needed to do the above where they cross more than one main transmission boundary. Note that both of the HVDC 'bootstraps' that may be built in the next decade (shown geographically in Figure 6 below) do in fact cross more than one main transmission system boundary so this is not an academic extension of the methodology.
- A consideration of how to calculate the unit costs of HVDC 'bootstraps' (Theme 5 – unit cost of transmission capacity - included by National Grid in their paper)

Figure A4.1: Geographical Representation of Proposed HVDC links

Why the existing ICRP methodology does not work for HVDC 'bootstraps'

The core of the ICRP methodology is that, taking each node in turn, an additional MW of generation is applied and this is balanced by a corresponding increase in demand to rebalance the system at a reference node in the notional centre of the transmission network. The change in flows in each transmission circuit is subsequently calculated and multiplied by the notional length of each circuit (which for a 400kV overhead line is equal to the actual length) to produce a total increase (or decrease) in MWkm across the network. Finally, these MWkm are then multiplied by the unit cost of transmission (called the expansion constant) to produce the marginal cost of reinforcing the whole system to accommodate the additional MW.

In a system of interconnected AC transmission circuits the power (and the incremental power) for any combination of nodal injections and withdrawals will flow along each circuit in a manner determined entirely by the network topology and the relative reactances of each circuit (it is a DC load flow study approximation, which for the avoidance of doubt assumes constant voltages and neglects losses in order to be able to solve the problem with linear simultaneous equations; i.e. the term DC is unrelated to DC transmission).

Conversely, the power flow on an HVDC link, such as the 'bootstraps', can be set manually to any desired value (within the link rating) and this is what determines the flow down it. Altered conditions on the transmission system will not alter this flow automatically and so incrementing the generation at one node and compensating by adjusting the total system demand to balance this does not produce any change in flow on a HVDC link. The current ICRP methodology of increasing generation (say) at a node by 1MW, balancing it by a corresponding reduction at other nodes and observing the automatic change in network flows which is translated into a change in MWkm for each circuit does not therefore work. For an ICRP system that is meant to be cost reflective the conclusion that there is no incremental flow and therefore no cost recovery for such HVDC links is not a sensible result and one therefore needs to develop a methodology that results in some change in incremental flow on the DC circuit.

Options for imputing incremental flows on HVDC 'bootstraps'

Before splitting the discussion into a basic methodology and an enhancement to cope with 'bootstraps' crossing multiple transmission boundaries, an alternative methodology that has been proposed but is not considered suitable to take forward is described.

<u>Academic suggestion that it is recommended is rejected</u>

It has been suggested that a way around this issue is to use an optimal power flow with and without the incremental change in injection at the node being measured. Ignoring the extra complexity of undertaking an optimal power flow the Working Group member believed this is liable in many cases not to produce a sensible result as it will often produce an optimum power flow (secure network with minimised losses) to run the HVDC link at full power. This would produce the same flow on the link with and without the incremental injection and thus assign no cost to the link. This effectively gives the same result as using the argument that because there is no automatic change on the HVDC link as a result of incremental generation at any node, no locational charges should be generated by the link.

Although it may be argued by some that this is the "correct" answer it does not appear to be compatible with any notion of cost reflectivity and therefore for a methodology that is meant to be reflective of transmission costs and the locational variation of these costs a different methodology is required.

A possible solution for a link crossing a single transmission boundary

The solution that has been suggested is to model the HVDC 'bootstraps' as an AC circuit with an "appropriate" impedance which would allow for incremental flows on this AC equivalent transmission circuit as a result of incremental injections and withdrawals that can be translated into a change in MWkm and hence cost. The issue is what is the "appropriate" impedance? One can think of the appropriate impedance in terms of the impedance that would produce a particular pre increment flow in the line.

<u>Methods of calculating the "impedance" of the AC "equivalent" to an HVDC link</u>

One can postulate a number of methods to impute an equivalent impedance. These include:

1. **Optimal Power flow.**

As the impedance can be calculated from a particular pre incremental injection flow in the transmission line one could derive this flow from an optimal power flow (which could result in the line running pre increment at the full rating of the HVDC link). Whilst deriving the flow from which to calculate the impedance that would produce this flow from an optimal power flow has its philosophical attractions it would be quite resource intensive and there are simpler methods that have a similar level of logical justification (see 4 below). It does however have the advantage that there would be no additional complexity from 'bootstraps' crossing multiple transmission boundaries.

2. **Number of transmission "routes" across the boundary**

This involves counting the transmission routes across a transmission boundary and assuming equal flows on each route, counting a double circuit overhead line as one route on the basis that both an HVDC link and a double circuit overhead line both constitute a credible contingency for network planning. Thus for a boundary crossed by two double circuit overhead transmission lines and one HVDC 'bootstrap' you assume 1/3rd of the flow goes down each and calculates the impedance of the AC equivalent of the 'bootstrap' to result in 1/3rd of the boundary flow being along it pre incremental injection / withdrawal.

This method is simple, but may also have some disadvantages. It is not immediately clear how one would treat routes of different voltage and hence possibly significantly different capacities. In an example presented to the Working Group for the proposed Scotland / England and Wales 'bootstraps' the 132kV interconnector was ignored for simplicity as it does not provide a significant amount of transmission boundary capability (i.e. the boundary is not limited by thermal, 'capacity', constraints), which is a possible way around this but somewhat arbitrary. It is also possible to postulate a case where the rating of the HVDC 'bootstrap' is relatively low compared to the AC routes across the same transmission boundary and sharing the flows equally could produce an imputed flow (and hence AC equivalent impedance) in the HVDC link that exceeds its rating which does not feel right. Nevertheless, as the current DC load flow model does not take into account the ratings of transmission circuits, the aforementioned concerns do not necessarily rule out this approach. Indeed, the biggest advantage of this approach is its simplicity.

3. **Number of transmission circuits across the boundary**

This is an obvious variation of method 2 so that, for example, on the Anglo Scottish transmission boundary instead of assuming that the two double circuit overhead line routes and one HVDC link share equally (ignoring the 132kv interconnection) one says that all of these transmission circuits (apart from the 132kv interconnection) share the flow equally and therefore the HVDC link would be assumed to carry 1/5th of the flow and have its equivalent impedance calculated accordingly.

This has the same advantages and disadvantages as method 2 above but if double circuit routes cross the boundary produces a lower base case flow than method 2 because one is counting transmission circuits rather than routes. The definition of a 'secured fault' (otherwise known as a credible contingency) in the NETS SQSS planning standard and its application to HVDC links may provide some guidance as to the relative attractiveness of methods 2 and 3.

4. Apportioning flows in proportion to transmission circuit ratings

In theory, with an optimally designed network of parallel transmission circuits crossing a transmission boundary the circuit impedances are in inverse proportion to the circuit ratings (so that they will share the power flow in proportion to their ratings) so there is an argument to choose the equivalent AC impedance for the HVDC 'bootstrap' according to that. In other words choose an impedance that will produce a power flow down the equivalent AC transmission circuit as a ratio of its rating that is the same as the ratio of the total transmission boundary flow is to the sum of the ratings of all circuits that cross the boundary. This has a logical basis, maintains a relatively simple approach, and allows all transmission circuits of all voltages across a transmission boundary to be taken into account and cannot produce a notional pre injection / withdrawal flow on the HVDC 'bootstrap' that exceeds its rating.

Example of method 4 – apportioning flows in proportion to transmission circuit rating

Consider a boundary with a 2GW capacity HVDC 'bootstrap' connecting one side to the other and 5 other AC single transmission circuits crossing the transmission boundary with ratings of 1.5, 1.7, 2.1, 2.5 and 2.9GW. The arithmetical sum of the capability of the boundary circuits is 12.7GW. The equivalent impedance of the 2GW HVDC 'bootstrap' should be set such that 20/127ths of the boundary flow goes through its equivalent AC circuit. The incremental flow down it can then be found via a load flow study in the normal way. In order to calculate the 400kV overhead equivalent length, the incremental MWkm is of course then multiplied by the appropriate expansion factor for HVDC links of the appropriate type, which will be discussed later.

Of all the above methods proposed, none will represent how the HVDC link is actually operated (although in principle the optimal power flow should come close) as this is up to the conditions on the transmission network and System Operator actions at a given point in time. Therefore, whilst based on some underlying assumptions and representing an approach based on logic, none of the above methodologies is inherently more 'correct' than another. However, on balance, it is recommended by the Working Group that to calculate the equivalent AC transmission circuit impedance of an HVDC 'bootstrap', method 4 is used.

Effect of choosing different impedances on HVDC 'bootstraps'

It should be noted that the effect of choosing a different equivalent impedance on the HVDC 'bootstrap' is that the lower the equivalent impedance the greater proportion of any incremental flow across a transmission boundary that will flow along the HVDC link. To take the extremes if one were to assume zero impedance then 100% of the incremental flow would be along the HVDC link and if one were to assume an infinite impedance none of the incremental flow would be along the HVDC link. This affects locational charge differentials if the HVDC link has a different reinforcement £/MW cost (taking the different length into account) than the other transmission circuits that it parallels. If one assumes that it has the same cost / MW to reinforce incrementally as the transmission circuits it is in parallel with it would not matter how much of the incremental flow went along the 'bootstrap' compared to the other circuits.

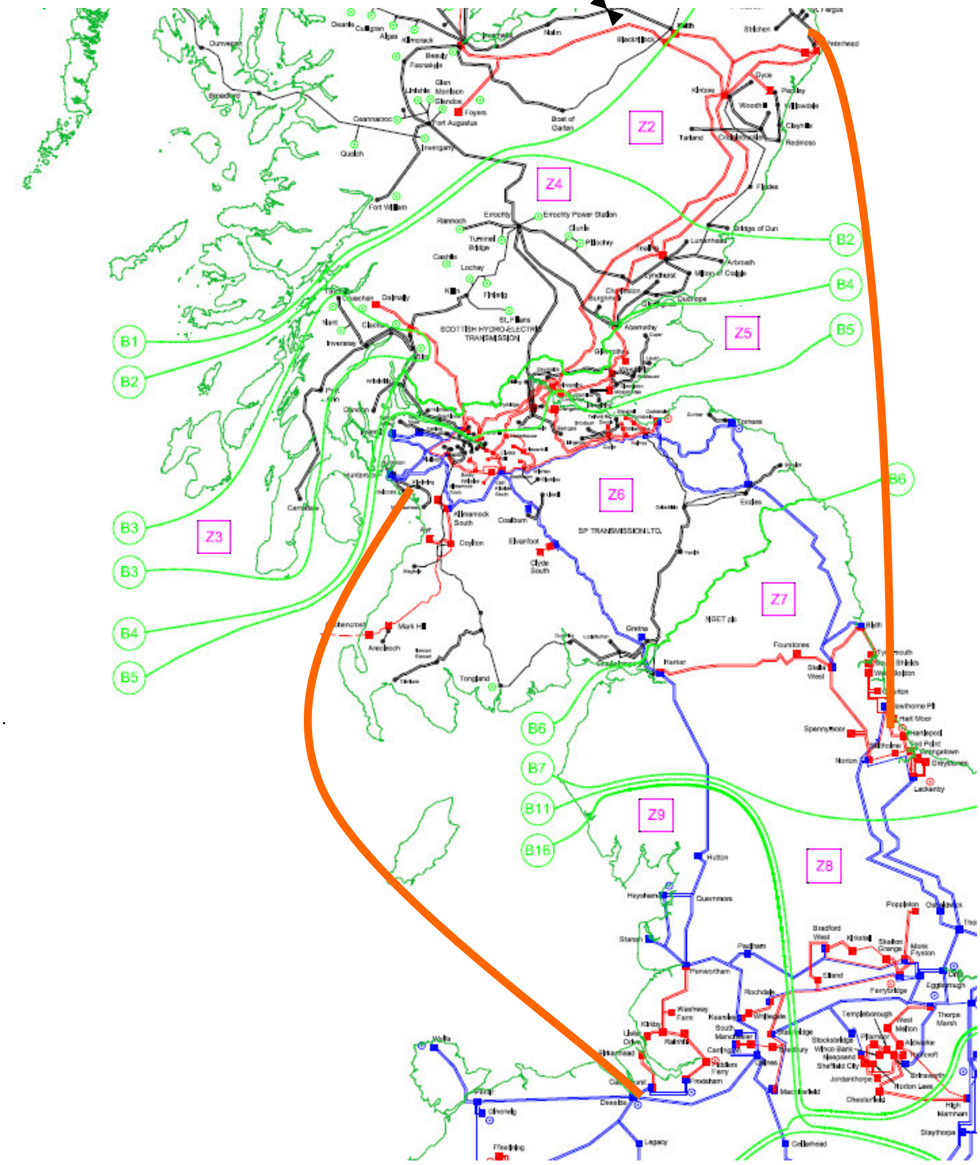
HVDC 'Bootstraps' crossing more than one main transmission boundary

Up to this point only HVDC 'bootstraps' crossing a single transmission boundary have been considered. However, an HVDC 'bootstrap' may in fact cross more than one main transmission system boundary. Indeed the proposed ones between Scotland and England & Wales do; i.e. they do not cross only the Cheviot (SYS – B6) boundary (as shown in Figure 7 below).

When one has an HVDC 'bootstrap' in parallel with several main transmission system boundaries in series with generation and demand between each of those boundaries (as will be the case) methods 2, 3 and 4 above may need to be enhanced (as the different transmission boundaries crossed would have different numbers of AC routes / circuits / total capacities between them). Method 1 (optimal power flow) would in principle work with an HVDC 'bootstrap' crossing several main transmission system boundaries without enhancement. In addition if one put in place an accompanying methodology for choosing a single transmission boundary to choose out of the multiple boundaries crossed to use the single boundary methodology on, say, one that represents the initial binding constraint that drives the need for transmission reinforcement or one that has the lowest capacity (or capability), methods 2, 3 and 4 for a single boundary would also present workable approaches (as one would "pretend" that they were the only boundary).

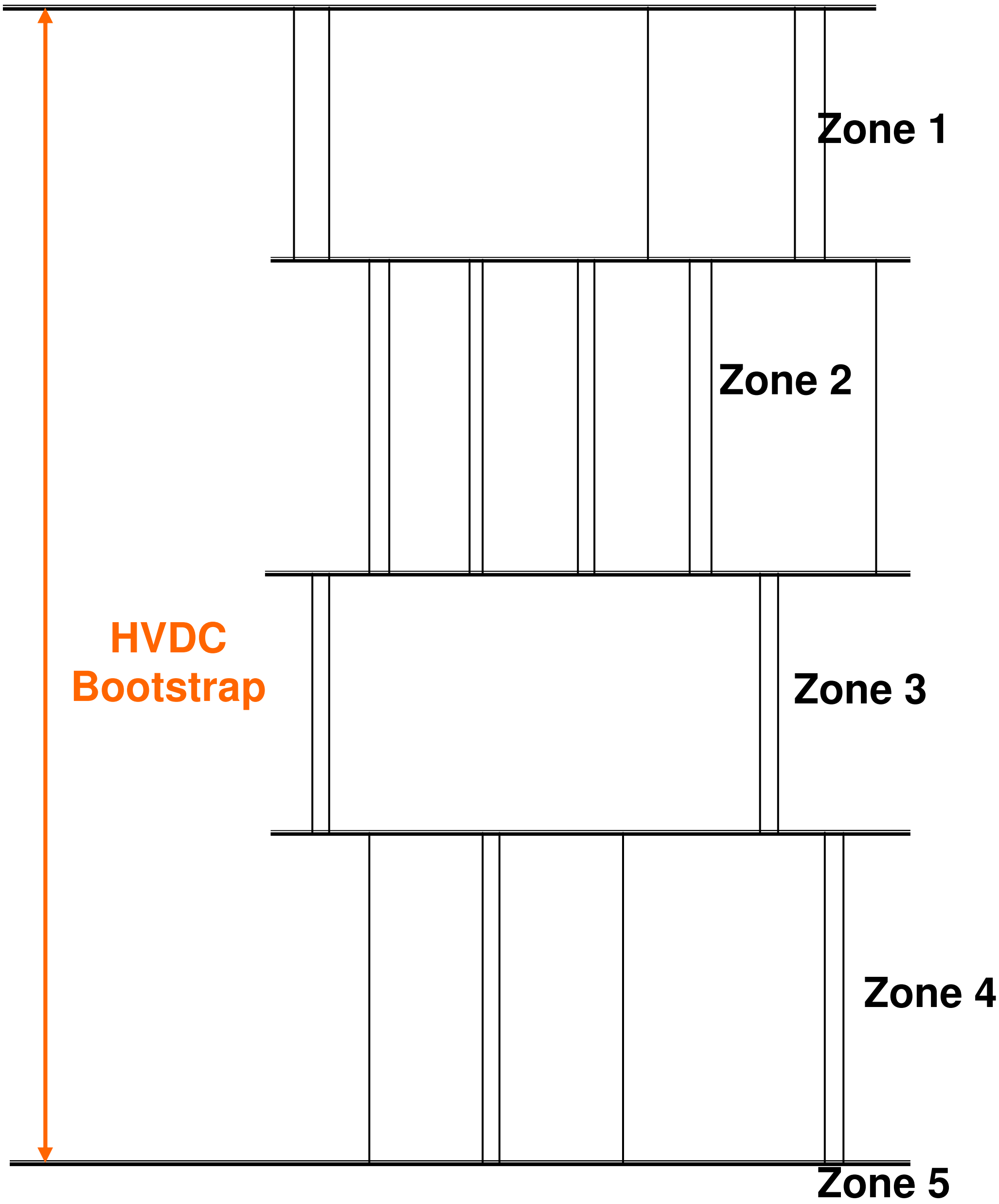
The issue is illustrated in Figure A4.2 below (reproduced from the National Grid Seven Year Statement with addition of bootstraps).

Figure A4.2: Illustration of HVDC ‘Bootstraps’ Crossing Multiple Transmission Boundaries



It can be seen from Figure A4.2 that both the proposed west coast Hunterston to Deeside and the east coast Peterhead to Hawthorne Pitt HVDC ‘bootstrap’ cross several main transmission boundaries. So for methods 2, 3, or 4 one is left with something looking in principle like what is represented below, in Figure A4. (which does not purport to represent the actual transmission boundaries shown in Figure A4.2 above). Horizontal lines represent the zones, vertical lines the transmission circuits between these zones.

Figure A4.3: Five Zone Example of Multiple Boundary HVDC



It can be seen from Figure A4.3 that the HVDC 'bootstrap' connects Zone 1 to Zone 5 and each of these zones are interconnected with the next one by a different number of transmission circuit routes, circuits and almost definitely total arithmetic sum of circuit capacities between zones. If one therefore wants to have the HVDC 'bootstrap' basic flow and hence AC equivalent impedance based on the number of routes or circuits between zones or capacity of the circuits between zones, one has to have a method for combining the transmission interconnections between the zones.

The method below is therefore suggested as how to deal with an HVDC 'bootstrap' crossing several transmission system boundaries assuming that method 4 above is chosen; i.e. the equivalent impedance is chosen so as to share pre incremental injection flows in proportion to transmission circuit ratings.

<u>Suggested methodology for sharing in proportion to circuit ratings where multiple transmission boundaries are crossed</u>

Sum arithmetically the ratings of all transmission circuits that cross each transmission boundary individually excluding the 'bootstrap', look at the flow across each boundary without any flow on the 'bootstrap' (this is necessary to produce a unique result) and then for each boundary evaluate a ratio of flow to boundary total circuit rating, accounting for the direction of the boundary flow in the base case. Accounting for the direction of transmission boundary flow is necessary as it is possible for the flow direction across some of the boundaries in series to be in a different direction to flows across other boundaries. One can then get an average for all transmission boundaries that the 'bootstrap' crosses of a flow to total circuit rating figure and set the impedance of the 'bootstrap' AC equivalent transmission circuit to produce the flow that gives this ratio to the 'bootstrap' rating.

<u>Alternative methods for dealing with 'bootstraps' that cross several transmission system boundaries</u>

There are a number of other methods that could be used for dealing with multiple transmission boundaries. They are basically either use the optimal power flow method 1 above for setting the flow on the HVDC link when multiple boundary crossings do not present additional complexity or choose one of the boundaries crossed based on an agreed methodology and focus only on that boundary. All of the methods below for choosing one transmission boundary to select are simpler than the above but could be considered more arbitrary. Alternative methods include:

1. Use the transmission boundary that is closest to requiring transmission reinforcement (i.e. the weakest link in all those crossed by the HVDC link) and, recognising that the System Operator is likely to be focused on this boundary at high flow conditions as the pinch point on that part of the transmission network, focus on balancing power flows on only that boundary. A possible drawback with this is that, in principle there may be a relatively low capability transmission boundary that is crossed that is actually the one most close in the scenario to requiring reinforcement and this boundary would then determine setting the flow on the HVDC 'bootstrap' and determining its impedance when arguably its "main function" is to cross other boundaries.

2. Use the "longest" transmission boundary that is crossed. One could argue that this is nominally the most expensive boundary to reinforce (assuming all circuits use the same cost of reinforcement per MWkm) and therefore the one that the HVDC 'bootstrap' flow should be set on.

3. Use the transmission boundary with the largest existing flow across it in the scenario being modelled.

4. Use the transmission boundary that would be the most expensive to reinforce in isolation

How to calculate per MWkm cost (Expansion Constant) of HVDC 'bootstraps'

Three ways have been postulated for evaluating the unit cost of HVDC 'bootstraps'. The more of the actual costs that are included the higher the (transmission) charge differential between the two ends of the 'bootstrap' will be in cases where the equivalent AC impedance is calculated with one of the aforementioned approaches and not set to an extremely high level. In principle, at one extreme, if the 'bootstrap' is taken as having costs equal to that of 400kV overhead line, then adding an HVDC 'bootstrap' will make little difference to the charge differential of the two ends of that 'bootstrap'. This is a basic feature of the ICRP methodology under which if a number of equal length 400kV overhead line circuits (or any other type of circuits of equal cost characteristics) cross a transmission boundary adding additional transmission circuits of the same type makes no difference to the (transmission) charge differential at each end. This is largely due to the fact that ICRP does not take transmission circuit capacity into account.

The alternative methods suggested are:

A) Treat the cost of the HVDC 'bootstrap' as the same as that of a 400kV overhead line of the same length. The argument for this is that one would ideally have built a 400kV overhead line but the length of time to get planning consent (if its granted) for one makes that uneconomic. If one follows this argument then to be consistent one could consider that one should cost virtually all transmission circuits as overhead lines, and ignore sections of AC underground cabling because that is what one would always build if one could for purely economic reasons.

   A second argument that has been put forward by some in the Working Group that could lead to such an approach (i.e. the outcome of which is the majority of the cost being collected through the residual element of the TNUoS tariff) is that HVDC links represent a strategic asset, ostensibly put in place to allow Great Britain to meet its 2020 renewable targets, and should therefore be charged on this basis. One could of course apply the same argument to all transmission reinforcement required to meet these targets.

B) Take into account the actual cost of HVDC subsea cable but ignore the cost of the convertor stations at the ends of the cable link. The argument for this is that these convertors can often provide reactive compensation and post fault power flow redirection services which is a system benefit and currently (rightly or wrongly) not taken into account in determining ICRP locational differentials (i.e. shunt reactive compensation devices and quadrature boosters are not included in the expansion constant or expansion factors). If one were to go down this route there may be an argument that one should add any additional cost of the reactive compensation provided by the convertors over and above the cost of standalone reactive compensation equipment / quadrature boosters that could have provided the same variable reactive power resource / power flow control.

A second argument that has been put forward by some in the Working Group for this approach is that HVDC converter stations are akin to transformers and substations on the AC transmission network and that these items are also not factored into the expansion constant or expansion factor calculations.

C) Take into account the entire cost of the HVDC link including the convertors at each end of the circuit. As the links could not be used to transmit power without these convertors it can be argued that this is the most cost reflective option. Indeed the lower £/MWkm cost of HVDC subsea cables relative to underground AC transmission cables (i.e. almost half the cost) would not be possible without AC/DC conversion technology. The relative economics of AC versus DC is therefore distance dependent. Excluding the cost of converters would distort this signal. Thinking of the extreme case of two back to back HVDC convertors (used in some parts of the world) is instructive in considering the extent to which the transmission charging signal would no longer represent transmission network expansion costs.

Effect of options on charges

The following section sets out the impact of various approaches to incorporating HVDC 'bootstraps' into the ICRP charging methodology. Options for both the cost component and treatment of the incremental MW flow (i.e. impedance calculation) are covered in turn. These set out the envelope of the most extreme potential impacts, considering all possible options and seek to illustrate the potential impact for a specific methodology, on a generic basis initially.

Calculations are undertaken using the existing transmission charging methodology (as set out in section 14 of the CUSC) for calculation of an HVDC expansion factor. Therefore when annuitising costs a discount rate of 6.25%, asset life of 50 years and overhead factor of 1.8% are used. These factors may be subject to change under the ongoing RIIO Transmission Price Control Review process for the period starting in 2013.

It should also be noted that any illustrative tariffs provided in this section are calculated in the 2011/12 Transport and Tariff Models and **do not include the effects of any other changes** being considered as part of the remaining five Themes under consideration within the Project TransmiT Significant Code Review technical Working Group.

Following on from the generic impact illustration, specific calculations are undertaken for each of the options outlined above to calculate the impedance of the HVDC 'AC equivalent' transmission circuit.

Expansion Factor Calculation

The current transmission charging methodology calculates an expansion factor used to refer the costs for a given transmission technology back to that of the baseline technology of 400kV overhead line. This approach takes the capital cost of a technology, in this case HVDC, annuitises this cost (using the assumptions outlined above) and adds an overhead factor for Transmission Operator overheads (such as maintenance, rates, etc.) to achieve the total annual cost in £m. This annual cost is subsequently divided by the rating and length of the transmission circuit to achieve a unit cost per MWkm. The expansion factor is simply a multiplier from the expansion constant (i.e. unit cost per MWkm of 400kV overhead line). In 2011/12 the expansion constant is £11.1429/MWkm.

The values set out in the above calculation, along with expansion factors for other transmission technologies in 2011/12 are shown in Figure A4.VII, below

Figure A4.VII: 2011/12 Expansion Factor Inputs and Examples

Annuity Factor:	0.06567
Asset Life:	50
Rate:	0.0625
Overhead Factor %	1.8
Expansion Constant (£/MWkm)	11.142856

Existing Expansion Factor Parameters			
Projected Relative Cost of Asset	NGC	SP	SSE
400kV cable factor	22.390	22.390	22.390
275kV cable factor	22.394	22.394	22.394
132kV cable factor	30.220	30.220	27.790
400kV line factor	1.000	1.000	1.000
275kV line factor	1.137	1.137	1.137
132kV line factor	2.796	2.796	2.238

These inputs shown above, are now used to calculate an example expansion factor that includes all the assumed costs associated with an HVDC 'bootstrap' link (as set out in method C, above). For this example, the cost of the HVDC link is assumed to be £1000m with a rating of 2000MW and length of 370km. The practical modelling of the HVDC in the Transport Model can be done either by modelling as a 400kV cable or a 400kV overhead line. The following example shows the calculation involved for both of these approaches and shows an excerpt from the Transport model spreadsheet, with the HVDC link modelled as its equivalent 400kV overhead line length:

Calculations

HVDC Details:	370.0	Length (km)
	2,000.0	Rating (MW)
	1,000.0	Total Cost (£m)
	65.7	Annuitised cost
	18.0	Overheads cost
	83.7	Total Annual Cost (£m)
£/MWkm:	113.1	£/MWkm
	10.1	HVDC expansion factor
Transport Model:	167.7	Equivalent length of 400kV cable
		or
	3754.4	Equivalent length of 400kV OHL

Assumptions for illustration

Bus 1	Bus 2	R	X	OHL Length	Cable Length
DEES40	HUER40	0.000	????	3754.400	0.00

Example Unit Cost Calculations for Different Approaches

As outlined above, three possible approaches have been discussed in relation to the calculation of an HVDC 'bootstrap link'. These are summarised in the table, below.

Option A	Option B	Option C
No suitable onshore alternative	**SO flexibility akin to SVC or QB**	**Full marginal signal**
▪ Treat as 400kV OHL ▪ Little impact on tariffs ▪ Regardless of MW flow	▪ Remove converters from EF ▪ Some impact on tariffs ▪ Varies by MW flow	▪ Include all elements in EF ▪ Significant impact on tariffs ▪ Varies by MW flow

The calculations for all three options are shown side by side, below:

Calculation - Option A

HVDC Details:	370.0	Length (km)
	2,000.0	Rating (MW)
	1,000.0	Total Cost (£m)
	-	Annuitised cost
	-	Overheads cost
	-	Total Annual Cost (£m)
£/MWkm:	11.1	£/MWkm
	1.0	HVDC expansion factor
Transport Model:	16.5	Equivalent 400kV cable km
	or	
	370.0	Equivalent 400kV OHL km

Calculation - Option B

HVDC Details:	370.0	Length (km)
	2,000.0	Rating (MW)
	550.0	Total Cost (£m)
	36.1	Annuitised cost
	9.9	Overheads cost
	46.0	Total Annual Cost (£m)
£/MWkm:	62.2	£/MWkm
	5.6	HVDC expansion factor
Transport Model:	92.2	Equivalent 400kV cable km
	or	
	2064.9	Equivalent 400kV OHL km

Calculation - Option C

HVDC Details:	370.0	Length (km)
	2,000.0	Rating (MW)
	1,000.0	Total Cost (£m)
	65.7	Annuitised cost
	18.0	Overheads cost
	83.7	Total Annual Cost (£m)
£/MWkm:	113.1	£/MWkm
	10.1	HVDC expansion factor
Transport Model:	167.7	Equivalent 400kV cable km
	or	
	3754.4	Equivalent 400kV OHL km

Generic Illustration of Impact on Tariffs for Single HVDC 'Bootstrap'

As set out in the paper, above, the proposed approach to incorporating HVDC 'bootstrap' links is to model an 'AC equivalent' transmission circuit. The key element of this modelling is how the impedance will be represented. Also described above is the relative effect of choosing an impedance that is zero versus one that is infinite. In order to represent this complete spread of possible outcomes on TNUoS tariffs and define the envelope of potential outcomes, the following generic scenarios of impedance (***X***) for a single HVDC link to be modelled have been chosen:

Scenario 1: ***X*** = 0.0001 (i.e. near zero)
Scenario 2: ***X*** = 2 (i.e. possibly representative of one of the specific methods outlined above)
Scenario 3: ***X*** = 99999 (i.e. very large)

The above scenarios were then combined with the options for calculating the expansion factor and modelled in the 2011/12 Transport and Tariff model as follows:

Scenario	Option	EF	400kV OHL km	X	Flow	Total flow cost
1	A	1	370.0	0.0001	1370.23	506985.1
	B	5.6	2064.9	0.0001	1370.23	2829387.9
	C	10.1	3754.4	0.0001	1370.23	5144391.5
2	A	1	370.0	2	768.79	284452.3
	B	5.6	2064.9	2	768.79	1587474.5
	C	10.1	3754.4	2	768.79	2886345.2
3	A	1	370.0	9999	0.35	129.5
	B	5.6	2064.9	9999	0.35	722.72
	C	10.1	3754.4	9999	0.35	1314.0

*Note: the additional allowed revenue associated with HVDC links has not been added to the MAR for this illustration

The outcome for this matrix of scenarios and options are shown for generation and demand tariffs in Figure A4. and Figure 4. respectively.

Figure A4.4: Generic Illustrative Generation Tariffs

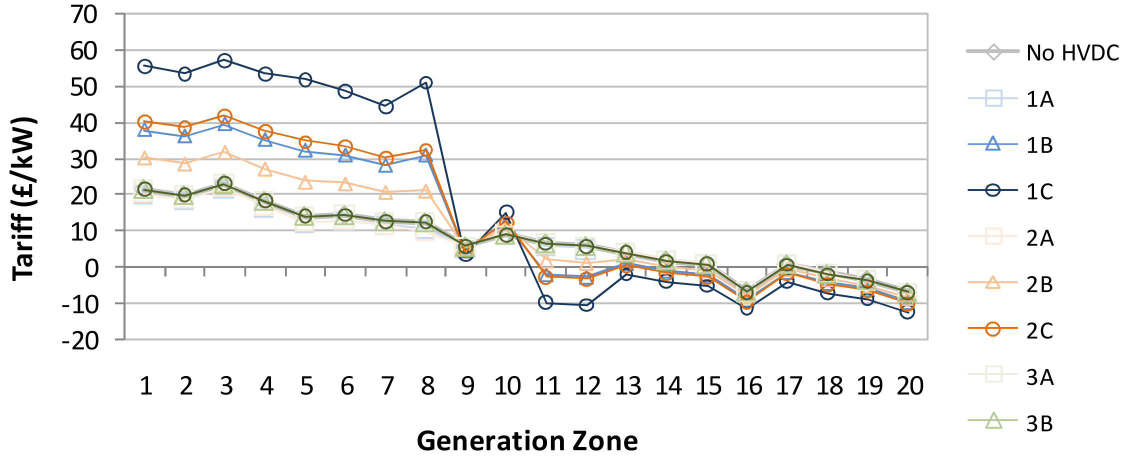
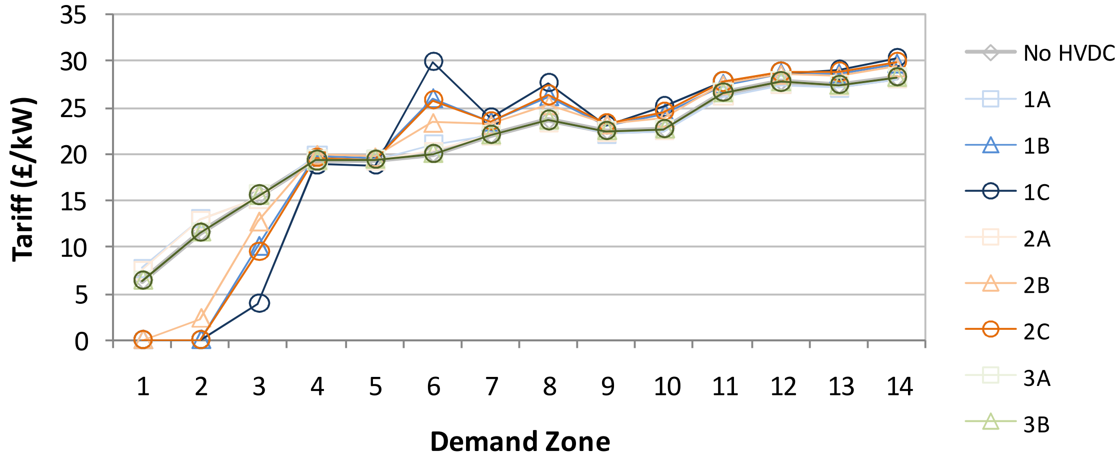


Figure 4.5: Generic Illustrative Demand Tariffs



<u>Specific Illustration of Impact on Tariffs</u>

In one Working Group meeting, National Grid presented an illustrative impact on TNUoS tariffs of using the methodologies for calculating the AC equivalent impedance of the proposed western HVDC link to be used in the Transport Model. Impedance is calculated by first calculating what the flow would be across the HVDC link in the base case load flow, using generation, demand and circuit data from the Transport Model. These are outlined in detail, above, within this Annex. In summary these approaches are:

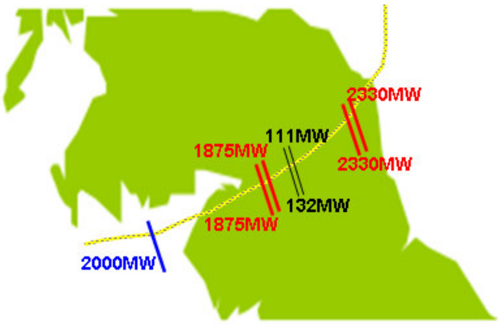
1. optimum power flow
2. base case flows in proportion to number of routes on a boundary
3. base case flows in proportion to number of circuits on a boundary
4. (a) base case flows in proportion to circuit ratings of a boundary
   (b) base case flows in proportion to circuit ratings averaged across multiple boundaries

The optimum power flow method was discounted by the Working Group. Therefore only methods 2, 3, 4(a), and 4(b) were modelled. In undertaking this modelling exercise, the following assumptions were made:

- The most constrained transmission boundary (i.e. B6) was used for the single boundary approaches (i.e. 2, 3, and 4(a)).
- For methods 2 and 3 the 132kV double circuit across the transmission boundary was ignored due to its relatively small size (i.e. 6% of the 400kV circuits. This left 4 circuits on 2 routes for these two methods.
- A 2011/12 Transport and Tariff Models were used; updated with 2015/16 'Gone Green' generation and demand assumptions.

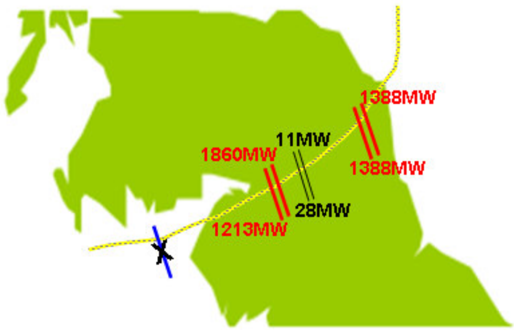
As a first step the total rating of the transmission circuits across the boundary was calculated as 10844 MW.

B6 Boundary Capacity



As a second step the total flow across the transmission boundary as a result of the generation and demand background in the Transport Model was calculated to be 5889 MW.

B6 Boundary Flow



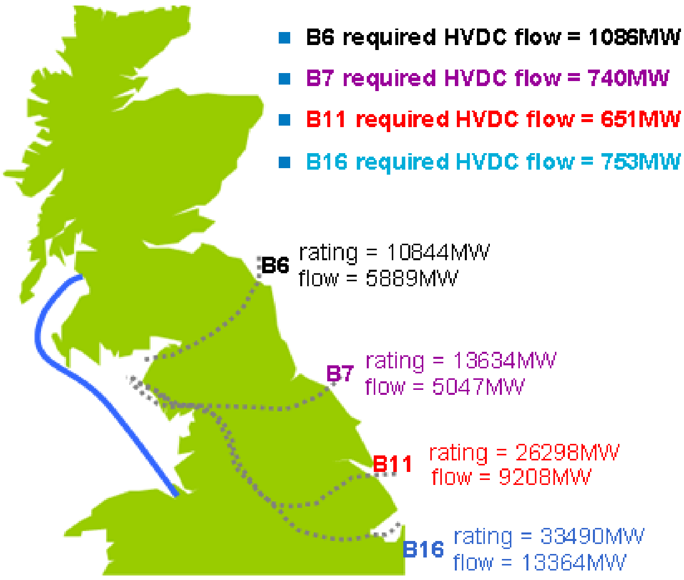
The third step was to calculate the desired HVDC flow using the relevant method. For methods using single transmission boundaries the calculations are as follows:

2. Transmission Routes $BF_{MW} * HVDC_{cap} / N_R$
3. Transmission Circuits $BF_{MW} * HVDC_{cap} / N_C$
4. Circuit Ratings;
   a. single boundary $BF_{MW} * HVDC_{cap} / BR$

Where;

BF_{MW} = MW boundary flow from Transport model with no HVDC
$HVDC_{cap}$ = MW capacity of HVDC circuit
N_R = No. of routes across boundary
N_C = No. of circuits across boundary
BR = total rating of boundary

In order to calculate the desired flow for method 4(b) (i.e. the multiple transmission boundary approach) the same calculation for method 4(a) must be undertaken for each boundary that the HVDC link crosses.



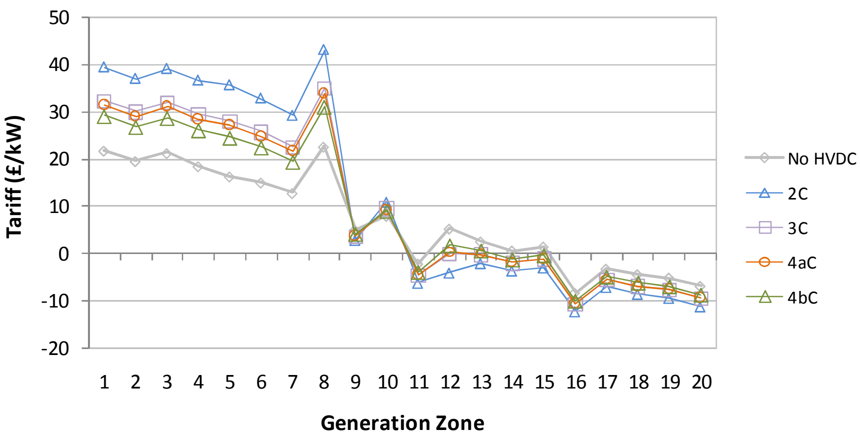
The following desired base case flows were calculated for each method:

- Method 2 1963 MW
- Method 3 1178MW
- Method 4a 1086 MW
- Method 4b 808 MW

An AC equivalent impedance is subsequently calculated to obtain the flows calculated above on the HVDC link in the Transport Model. The following parameters were therefore used in calculating illustrative tariffs:

Calculation Method	Cost Option	EF	400kV OHL km	X	Flow	Total flow cost
2	B	5.6	2064.9	1.92	1963	4053398.7
	C	10.1	3754.4	1.92	1963	7369887.2
3	B	5.6	2064.9	4.86	1178	2432452.2
	C	10.1	3754.4	4.86	1178	4422683.2
4a	B	5.6	2064.9	5.5	1086	2242481.4
	C	10.1	3754.4	5.5	1086	4077278.4
4b	B	5.6	2064.9	8.2	808	1668439.2
	C	10.1	3754.4	8.2	808	3033555.2

Only cost option C (i.e. all HVDC costs included in the expansion factor) was modelled for each method. The illustrative TNUoS tariffs arising out of each approach are illustrated, below.



Annex 5 – Detailed Options for Postage Stamp Models

Background

During the course of Working Group discussion, three postalised (or socialised) models have been proposed by individual Working Group members. Whilst debate originally centred on the scope of a postalised model (e.g. the meaning of the term "postalised", the treatment of demand charging, etc.), the discussion advanced to potential issues surrounding a change to the unit of charging, the preservation of certain charging characteristics (e.g. demand Triads) and the associated cash-flow implications of postalised models.

The key characteristics of each of the three postalised model considered by the Working Group are summarised in Table 1.

Table 1: Key differences between the proposed postalised approaches

Model	**Generation**			**Demand**		**Payment**			**Local Charges**
	Uniform	£/MW	£/MWh	Uniform	ICRP	Ex-ante	Ex-post	Reconcile	
A	✓		✓		✓	✓		✓	✓
B	✓	✓		✓		✓			
C	✓		✓	✓			✓	?	✓

As the table infers, the three key areas where the proposed models differ are:

a) the unit basis on which generation is charged, in terms of a commodity (MWh) or capacity (MW) charge and how the charges are applied (ex-ante or ex-post);
b) the treatment of local charges, in terms of whether separate local charges remain or all (both local and wider) charges are socialised; and
c) the treatment of charges for demand users.

The remainder of this Annex aims to provide more detail on each of the proposed three models. This paper does not evaluate the benefits or dis-benefits of adopting a particular postalised (socialised) model over another (or, in fact, over an ICRP model), but rather attempts to provide an overview of the differences between the proposed models and the reasons for the choices made by the respective proposers of each model.

Finally, it should also be noted that the proposers of the models put forward potential approaches to socialised charging for the purposes of the Redpoint modelling exercise. The proposers do not necessarily endorse a postalised / socialised approach to transmission charging.

Model A

The proposer of the first model suggests that all generators are exposed to the same rate of charge for injecting energy onto the GB electricity transmission system. Generators would move to a flat (non-geographical) commodity based (£/MWh) charging structure, where the TNUoS charges are calculated (annually, as now) ex-ante and recovered (monthly) ex-post based on the actual (monthly) output, with the aim of charging generators in direct proportion to their use of the transmission system (although a reconciliation of costs may be required to achieve this).

As the model aims to socialise the costs associated with areas of the transmission system that are, in essence, shared by multiple network users, the model only proposes to flatten the cost of the Main Interconnected Transmission System (MITS, as currently defined). Local charges would continue on the same basis as today, maintaining the principle of "User Choice" and retaining the signal to locate as close as possible to the MITS.

The proposer suggests that the MITS was established to provide a wider social benefit to users (consumers and generators), providing a secure / robust energy supply and ensuring generators are able to access the wider power market. The proposer also states that the vast majority (£321M / ~ 87% in 2011/12) of the wider generator transmission charges (£370M) are currently collected via the Rresidual element of the TNUoS residual charge, which is applied on a non-locational basis.

With regards to demand users, Model A proposes that transmission charges continue on the same basis as the current baseline; i.e. the ICRP charging regime. The proposer argues that demand should be out of scope for Project Transmit due to:

a) the key aim being to ensure transmission charging arrangements facilitate a timely move to a low carbon energy sector (which is a generation specific goal);
b) the Improved ICRP approach did not seek to modify demand charging (i.e. introduce "peak security" and "year round" elements to demand charges); and
c) the timescales associated with the Significant Code Review may be a limiting factor to the ability to modify demand charges in addition to generation charges.

It was also noted by the proposer that by maintaining the current transmission charging regime for demand, Model A would maintain the current Triad signal (i.e. the reduction of demand in extreme peak demand periods).

The calculation of transmission charges for generation users could work on a similar basis to the recovery of BSUoS charges today; i.e. the processes already exist to apply MW and MWh charges to users. The generation proportion of transmission charges for a given year would be divided by the total demand (MWh) expected for the given charging year, to provide an ex-ante commodity (MWh) based charge.

The proposer noted that National Grid currently bills generators, ex-ante, on an equal month-by-month basis across the charging year. This approach effectively dampens the effect of low summer troughs / high winter peaks in generation output. Whilst moving to an output (MWh) based transmission charging regime may assist generator cash-flow (as charges would theoretically mirror actual output), the variable monthly income may have a consequential effect on National Grid's cash-flow.

To address potential cash-flow concerns, the following potential charging and reconciliation options were put forward by the proposer:

i) Divide a generator's *forecast* annual charge equally by 12 months (i.e. 8% recovery per month):
    - Ex-ante charge based on National Grid's view on individual plant output (forecast);
    - Could be based on recent historic output data or the use of an ALF approach (as proposed by National Grid for use in the Improved ICRP approach);
    - Reconciliation for each generator, based on actual output, would occur at year end;
ii) A variation on i) with a seasonal demand profile:
    - This would also be reconciled on generator outturn;

iii) A variation on ii) with a charge based on the previous month's outturn:
   - This could be based on a) the actual monthly output in the previous month, b) the output in the same month the previous year, or c) an ALF approach on monthly generation patterns for the previous five years.

A further reconciliation may also be required for overall system under / over recovery for a charging year. It is expected that the mismatch between the forecast and the actual generator outturn, and total transmission system under / over recovery, would become more firm over the course of the year.

National Grid provided the Working Group with an indicative generation tariff rate (based on 2011/12 TNUoS revenues) for Model A of £1.193/MWh (plus each generator's local charge) for the current charging year (assuming 310TWh of GB generation output).

<u>Model B</u>

The proposer of the second model proposes that all generators are exposed to the same rate of charge for use of all (i.e. local and wider) transmission assets. Generators would move to a flat (non-geographical) capacity-based (£/MW) charging structure, where transmission charges would be calculated and recovered from generators ex-ante (as they are today).

The proposer of the second model suggested that the principle of socialisation is to not discriminate between users. As such, a socialised model should seek to expose all parties to a uniform rate of transmission charges, regardless of:

- geographic location;
- topological situation;
- the voltage at which the generator is connected;
- whether the generator uses (or is deemed to use) AC or DC assets; and
- whether the generator is connected onshore or offshore.

As such, the proposer of Model B suggested that there would seem to be very little point in differentiating between generators' local and wider works. The rationale for introducing the concept of local works was to improve cost reflectivity for the charging for local assets where, for example, lower levels of security exist than that implied by the security factor. The proposer believes the retention of a charge for local works would amount to cherry picking the aspects of transmission charges that should (or should not) be cost reflective.

On this basis, Model B proposes no local charging; i.e. local and wider charges are socialised via a single uniform charge. Connection charges would continue to be based on a very shallow PLUGS boundary.

The proposer believes that generators should be charged on a capacity (£/MW) basis, stating that there is no strong reason to choose either MW or MWh, other than for practical convenience. The proposer recognises that (a) in the past, there has been the argument that transmission investment is made to meet peak demand, hence the charge is currently based on capacity (i.e. MW) and (b) it is now argued that transmission investment is also driven by off peak running and that perhaps system usage is now important (i.e. ALF or MWh). However, the proposer feels that these arguments are redundant when simply socialising costs, as the drivers of cost / investment are deliberately ignored.

The rationale for Model B using a MW charge is simplicity, given the known total cost base and the total MW connected to the system; i.e. there is likely to be much less error associated with forecasting the total amount of TEC for a given year than there is for estimating the total amount of energy that will be generated during the same period. This allows Model B to calculate and recover charges from generators on an ex-ante basis without the need for a major reconciliation process due to under / over recovery. It should be noted, however, that the proposer believed a commodity (MWh) based charge could be used if there were a robust justification; however, they did not believe a robust justification had been put forward.

With regards to demand users, the proposer felt that there was little justification to charge generation and demand users on a different basis; this could be seen as discriminatory. As such, the proposed Model B retains the manner in which demand charges are currently allocated to demand users, except the locational element to the charge is removed to create a uniform charge. For the avoidance of doubt, it is only the value of the charge that changes (i.e. it is flattened), the recovery would continue on a £/kW and p/kWh basis for half-hourly (HH) and non-half-hourly (NHH) demand respectively. As with the previous model, this approach would maintain the current demand Triad signal.

National Grid provided the Working Group with an indicative generation tariff rate (based on 2011/12 TNUoS revenues) for Model B of £5.5984/kW (assuming 83.158GW of GB generation capacity) for the current charging year.

Model C

Model C was the final proposal to be put forward. The proposer of this model stated that it attempted to create a further solution that took elements from both Model A and Model B, but fundamentally differed by proposing an ex-post charge recovery process.

As with Model A, generators would move to a flat (non-geographical) commodity based (£/MWh) charging structure, where the unit charge is calculated ex-ante. However, unlike Model A, charges would be recovered ex-post based upon a generators' use of the transmission system.

It is proposed that generator transmission charges are calculated ex-ante by dividing the generation portion of transmission costs (which is known, with a very low risk of substantial movement within year) by expected demand (a forecast) [which National Grid already publishes]. Charges would then be apportioned to and recovered from users ex-post, based upon each users' output in a given settlement period (similar to BSUoS cost recovery).

The justification for this approach is that one of the major aims of Project Transmit is to facilitate investment in and move towards a low carbon energy sector. The proposer of Model C believes that the ability for generators to settle transmission costs post event would improve generator cash-flow. In addition, a commodity (MWh) based charge would mean that the charges incurred by a generator would have a direct link to their plant output, which would be more cost-reflective of a generator's actual use of the transmission system (versus a MW or ALF based methodology). The proposer recognised that a reconciliation process may be required at year end where there is a total under / over recovery of costs for a given year, although this could potentially be handled via an annual revenue correction mechanism (such as the K factor).

The proposer of Model C believed that local charges should be maintained, similar to Model A. The intention being to ensure that there continued to be a signal to minimise costs for *non-shared* transmission assets, preserving the notion of "user choice" for the design of local connections. However, the proposer also stated that this was open to change should the Working Group identify a robust justification to change the current practice.

With regards to demand users, Model C adopts exactly the same approach as detailed under Model B. The locational element of demand charges would be removed, creating a uniform demand charge. The manner in which transmission charges are currently allocated to demand users would be retained; i.e. the recovery would continue on a £/kW and p/kWh basis for half-hourly (HH) and non-half-hourly (NHH) demand respectively. This approach would ensure a consistent charging approach is taken for both generation and demand users whilst maintaining the current demand Triad signal.

An indicative generation tariff rate (based on 2011/12 TNUoS revenues) has not been considered by the Working Group. However, given the many similarities with Model A it could be expected that the generation TNUoS charge for Model C maybe similar to Model A – namely in the region of £1.193/MWh (plus each generator's local charge) for the current charging year (assuming 310TWh of GB generation output).

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Background

In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system. Additionally all chargeable generation is subject to the local substation tariff component. Demand users do not pay local charges.

These local generation charges (i.e. circuit and substation) are currently accounted for in the overall 27% of revenue recovery paid by generation users.

In order to ensure adequate revenue recovery, a constant non-locational residual tariff for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the corrected transport tariffs so that the correct generation / demand revenue split is maintained (currently 27:73) and the total revenue recovery is achieved. Formulaically, the calculation of the residual generation tariff is as below;

$$RT_G = \frac{[(1-p)\times TRR] - CTRR_G - LCRR_G}{\sum_{Gi=1}^{21} G_{Gi}}$$

Where;

RT_G = generation residual tariff (£/MW)

p = proportion of revenue to be recovered from demand

TRR = TNUoS Revenue Recovery target

$LCRR_G$ = Local Charge Revenue Recovery

$CTRR_G$ = "Generation / Demand split" corrected transport revenue recovery from generation

G_{Gi} = Total forecast Generation for each generation zone (based on confidential User forecasts)

Hence it can be seen that, as the revenue recovered from local charges ($LCRR_G$) increases, under the current methodology the generation residual (RT_G) will decrease.

The revenue recovered from local charges is forecast to increase primarily due to the increasing volume of offshore generation connections, which require a significant amount of relatively expensive local assets in the form of sub-sea cables and offshore platforms. The consequential effect on the generation residual charge was forecast in the 2010/11 National Grid Condition 5 Long Term Tariff Publication[43], and is illustrated graphically below in Figure I.

[43] http://www.nationalgrid.com/NR/rdonlyres/1DB70FA2-D218-4E6E-BA7D-0714A6B5A1E3/45139/201011Forecastoflongtermtariffs.pdf

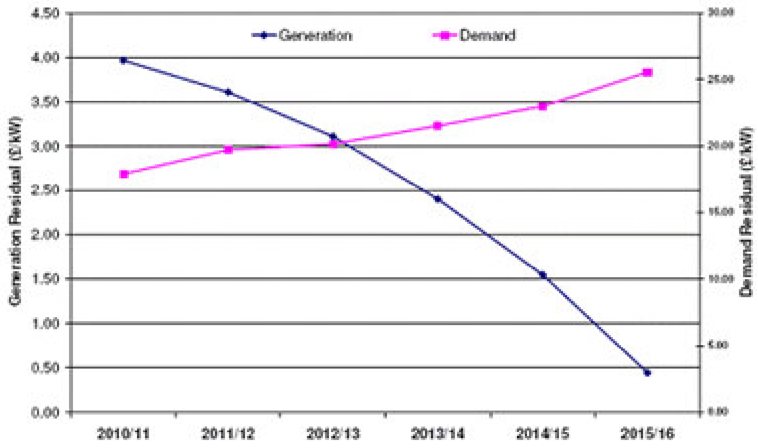


Figure 1 – Five year forecast of TNUoS residual charges

Working Group Discussion

Two members of the Working Group raised concerns over the interaction between revenue collected from generation local charges and the generation residual charge. Whilst these views had similarities, there were also fundamental differences between them.

The first view was that the relationship between revenue collected from local generation charges and the generation residual charge results in a non-cost reflective benefit to generation with lower local generation charges, i.e. onshore generators.

Many within the Working Group did not agree with this view as, whilst the flat residual charge changes equally for all generation users, the locational differentials between users remained the same.

The second view was that the falling residual charge, as a consequence of the inclusion of generation local revenues in the residual calculation, is an unintended consequence which significantly reduces the predictability of tariffs and could represent a windfall gain to generators as a whole.

Whilst not all Working Group members believed that the interaction between revenue collected from generation local charges and the setting of the residual charge was an issue, there was a broad opinion that the current methodology results in a local charge being applied to some generation users of such a size that it can have a material impact on the size of the generation residual charge. It was noted that this could have a disproportionate impact on revenue collection as a result of the application of the current G:D split.

Options Discussed

The two Working Group Members presented five options for change. The option of taking offshore assets out of the infrastructure, collected through use of system charges, and into connection assets, collected through connection charges specifically from offshore users was discounted as being out of the scope of Project Transmit.

Option 1 – Removal of revenue from local charges from the G:D split calculation.

This option is illustrated in Figure II below.

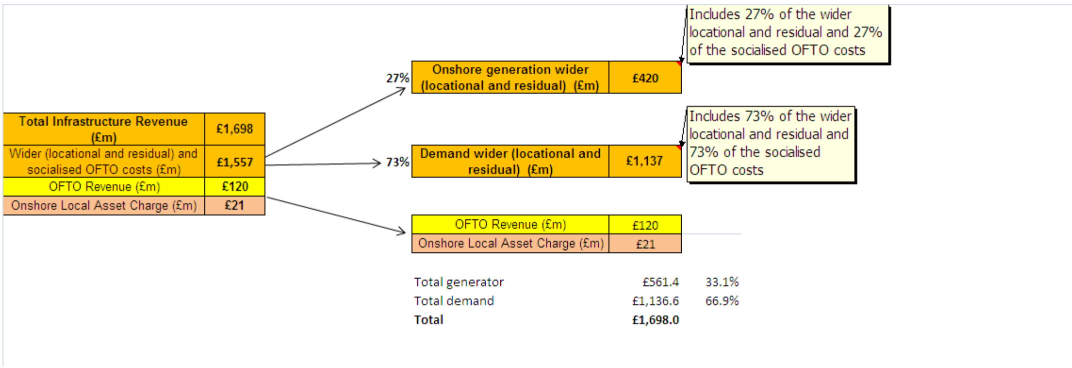


Figure II- Option 1 proposal with example

It was argued that this option offered the simplest fix to the perceived issue and would improve the ability of users to forecast tariffs. Working Group members concluded that this solution would result in the generation community paying a higher proportion of transmission costs. It was noted that EU tarification guidelines and Theme 6 Working Group discussions were suggesting a movement the other way (see section 9 of this report for further details).

Option 2 – Removal of revenue collected through local charges from the G:D split calculation with periodic reviews of the G:D split. This option is illustrated below in Figure .

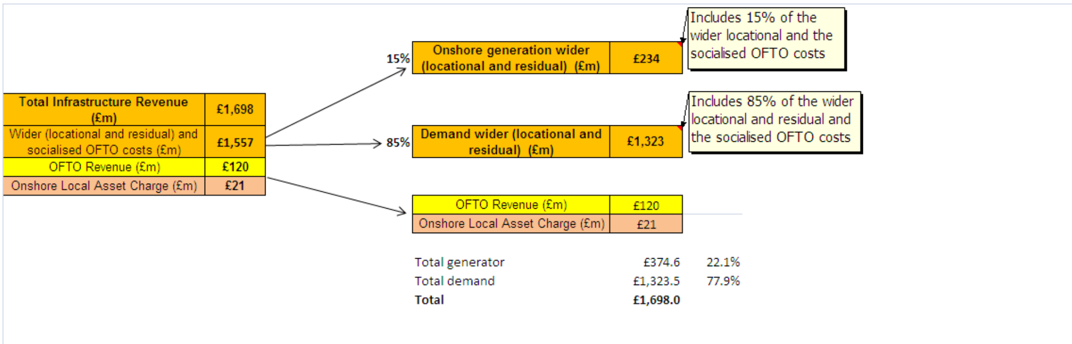


Figure III–Option 2 proposal with example

In this option the proportion of revenue required from generation users would be reviewed periodically (e.g. every 2-3 years), in effect 'fixing' the residual element for a set number of years in a transparent way.

It was argued that this would improve the ability to forecast tariffs, and would limit the overall revenue paid by generation in the medium term. However, National Grid would continue to publish a 5 year forecast of tariffs, as illustrated for the residual in Figure I. This option would lead to the proportion of total TNUoS revenue recovered from the generation community as a whole increasing over the 'fixing' period of the residual element. The net effect on tariffs of this option is the same as the status quo at the end of the 'fixing' period, after the step change takes place through the periodic review of the G:D split.

Option 3 – Offshore local asset revenue recovery split between generation and demand in ratio 27:73.

Under the current local circuit and local substation tariff approach, offshore generators will on average pay for between 80 and 90% of the cost of the offshore assets built specifically for their project. This option proposes to reduce this proportion to 27%, with suppliers picking up the remaining 73%. This would have consequential effects on the overall G:D split of TNUoS revenue recovery. These issues were not considered by the proposers of this option.

Option 4 – Offshore local assets charged as 400kV overhead line.

It was argued that by providing an expansion constant of 1 to offshore local circuits, this would be a similar treatment to an option proposed for the treatment of HVDC in Theme 4. It was also argued that, given the difference in asset lifetimes for offshore versus onshore assets (20 years vs. 50 years respectively), this lower initial charge could be accounted for in the long term. The working group members putting forward this option did not provide any detail for how this could be achieved.

As National Grid has a Transmission Licence obligation (Standard Condition C7) not to discriminate between users, this option is likely to require a change to the Transmission Licence due to the proposed special treatment granted to offshore generators. In effect, over the lifetime of an offshore generation project, transmission tariffs would be likely to collect < 5% of the cost of the local circuit assets built specifically for that generator under this option. The remaining users of the network (i.e. other generators and suppliers) would fund the remaining > 95%.

Option 5 – Remove the concept of local charges from generators.

This option would mean that offshore networks form part of the wider transmission network for charging purposes. As a result, under the current methodology, offshore grid entry points would form new generation zones (as differentials would be > +/- £1/kW). As the offshore expansion factors would continue to be reflective of the relatively high cost of sub-sea cables, wider locational offshore zonal tariffs would likely be similar to the tariffs calculated under the local circuit methodology. However, unless further changes are made to the methodology, offshore tariffs would also be multiplied by the global security factor of 1.8, rather than the current specific security factors of between 1.0 and 1.8. This outcome would is not sensible and changes would therefore have to be made. The Working Group members putting forward this option did not provide any detail for how this could be achieved.

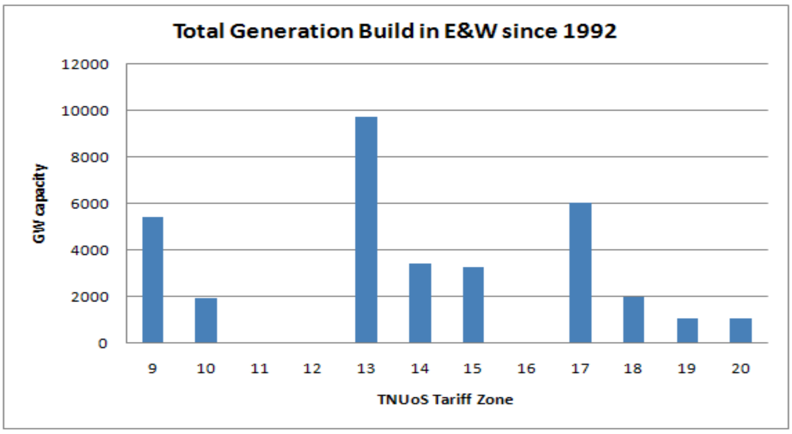
Annex 7 – Data on Current Contracted Generation Background

In order to inform the debate on issue of geographical differentiation of costs one Working Group member presented data from National Grid's TEC register[44] in support of the view that the Status Quo ICRP methodology had a limited effect on the locational siting of generation. Members noted that this was outside the remit of the Working Group.

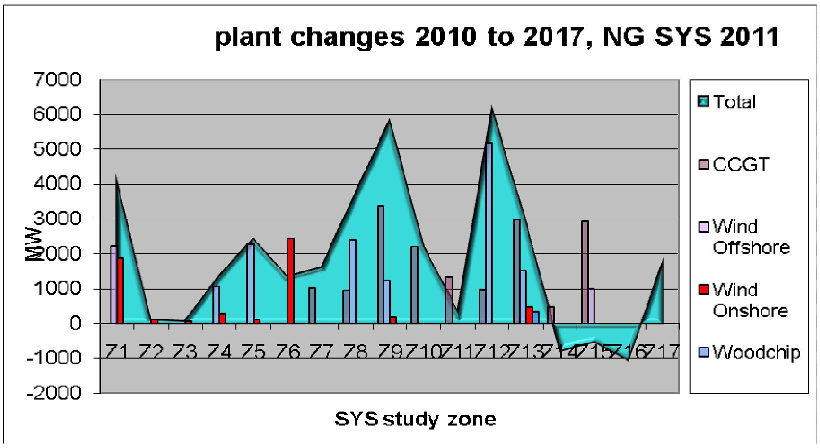
Furthermore, Working Group members noted that the underlying rationale behind TNUoS charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental transmission costs of supplying them. This did not preclude generators locating in areas that had higher transmission costs if other cost elements of their project led to a net positive outcome for a given location. In addition it was pointed out that one could only demonstrate that the current methodology had no effect if one could produce evidence of what would have happened with no locational differential in charges.

NOTE: This data has not been provided by National Grid. It originates from a variable data source (i.e. the TEC Register is updated regularly) and will therefore change over time.

Historical new build generation location in England and Wales since 1992 by TNUoS zones

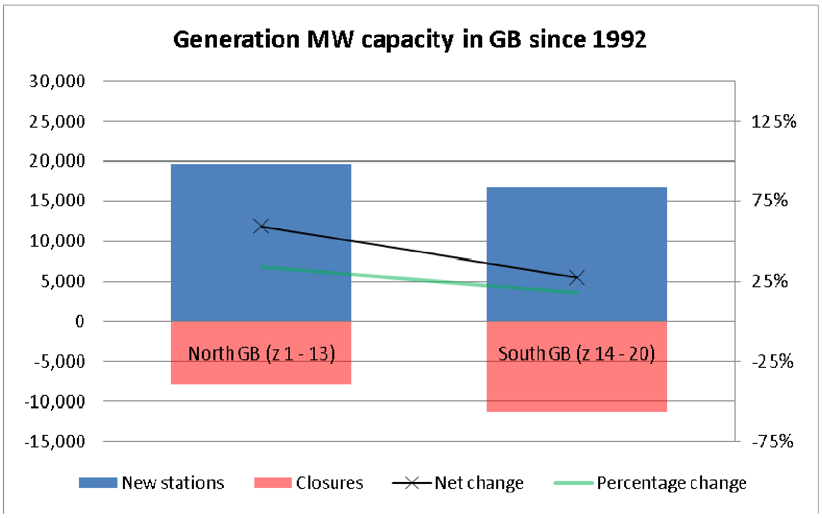


Forecast new build generation plant location in GB 2010-2017 by SYS zones



44 http://www.nationalgrid.com/NR/rdonlyres/AA41B933-3CE1-453B-8AE6-CAF387768837/48984/TEC12September11.xls

Historical new build generation / generation plant closure location across GB since 1992



Annex 8 – Illustrative Status Quo, Postage Stamp & I-ICRP Tariffs

2011/12 Illustrative Tariffs

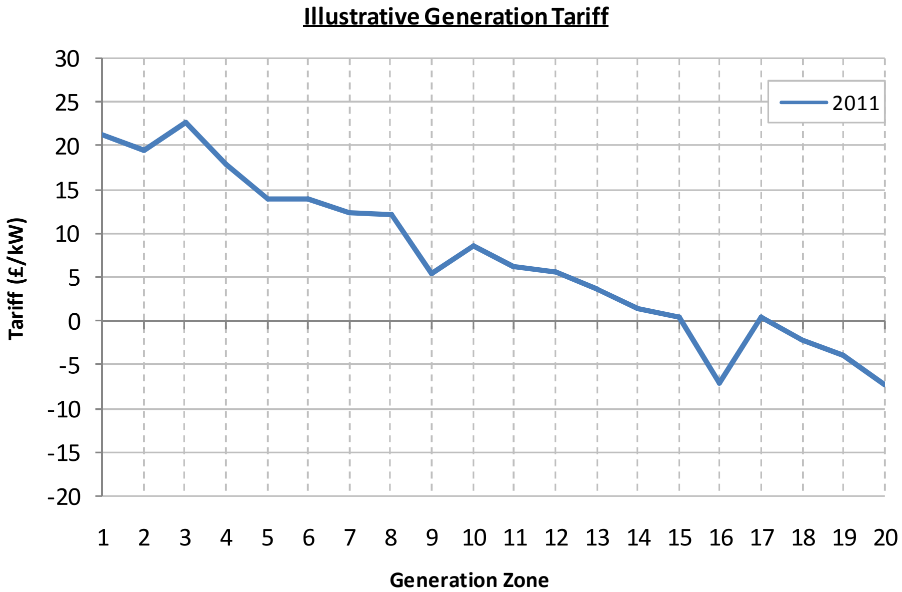
This annex provides two sets of illustrative tariffs related to options discussed by the Working Group. The first set is comprised of indicative tariffs produced by National Grid for status quo, improved ICRP, and postalised models. The second relates to tariffs formed by altering specific ICRP characteristics following Working Group discussions as part of theme 2

National Grid 2011/12 Indicative Tariffs

This section contains graphical illustrations of indicative TNUoS tariffs produced by National Grid at the request of the Working Group. Whilst they have been derived using three different Transport and Tariff model methodologies, the underlying data remains the same and is consistent with the existing 2011/12 DCLF model available on request via the National Grid website[45]. It should be noted that these tariffs are indicative only, and should not be considered accurate tariff illustrations for 2011/12, nor completely reflective of any indicative tariffs produced subsequently by the SCR impact assessment.

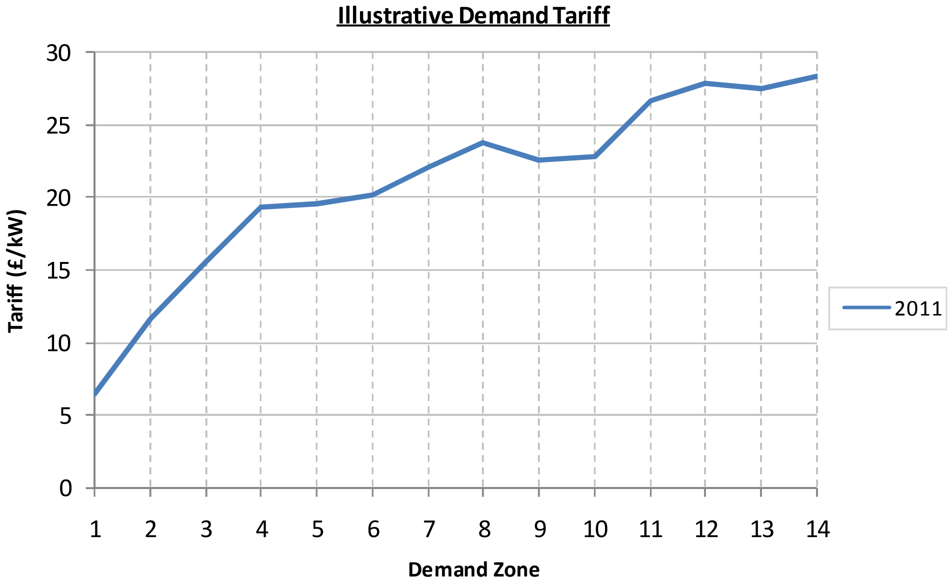
Status Quo Tariffs

The status quo tariffs align with the existing tariffs as defined in the Statement of Use of System Charges effective from 1st April 2011[46].



45 http://www.nationalgrid.com/uk/Electricity/Charges/transportmodel/

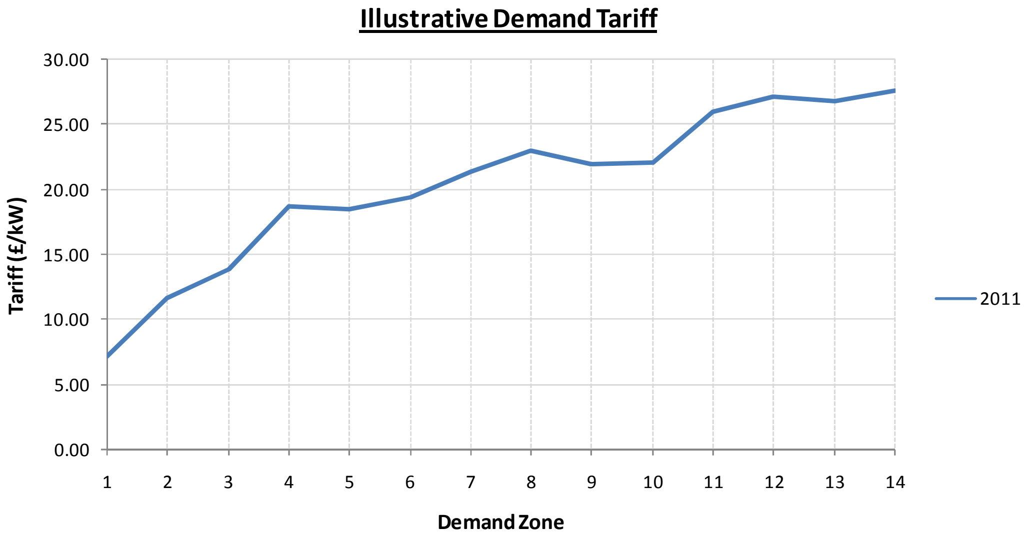
46 http://www.nationalgrid.com/NR/rdonlyres/0F5FBFA1-A94C-45DD-BAC0-C9A676737176/46235/UoSCI7R0Draft_Issued_FINAL.pdf



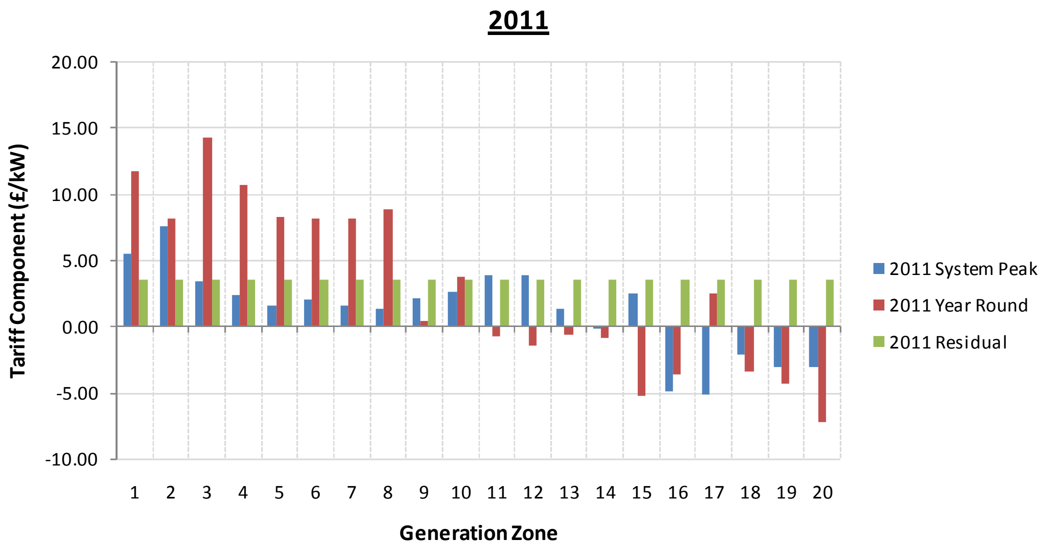
Indicative 2011/12 Improved ICRP Tariffs
The methodology utilised in the improved ICRP model is as follows;

- Theme 1 – National Grid's dual background proposal as defined in Annex 5
- Theme 2 – As status quo
- Theme 3 – As status quo
- Theme 4 - As status quo (no change until 2015)
- Theme 5 – As status quo
- Theme 6 – As status quo (no change until 2015)

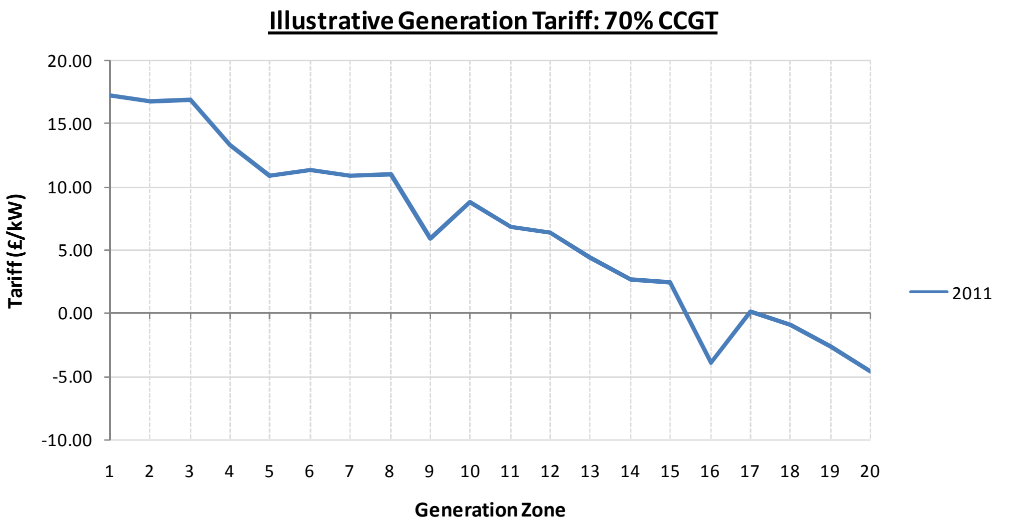
Indicative 2011/ 12 Improved ICRP Demand Tariffs
2011/12 illustrative demand tariffs for the improved ICRP model are illustrated below;

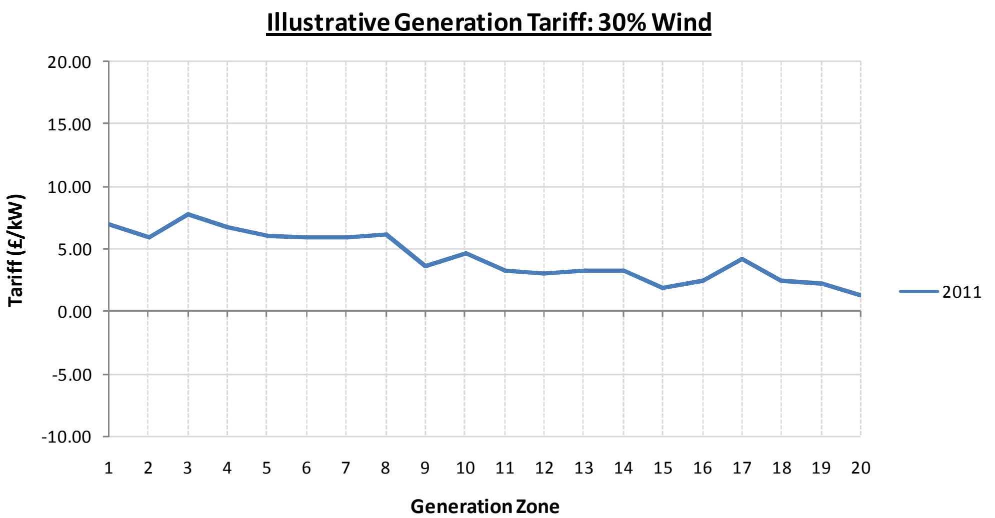


Indicative 2011/12 Improved ICRP Generation Tariffs
Due to the use of dual backgrounds, and the application of Annual Load Factor to generation user's specific tariffs, generation tariff illustration changes under the improved ICRP model. The chart below illustrates each of the three generation wider tariff components (i.e. peak security, year round, and residual);



However this chart alone does not provide an indicative illustration of the specific tariff a generation user may face. To assist in this illustration, the two charts below relate to the tariffs that would be charged to a 70% load factor CCGT and a 30% load factor windfarm respectively;

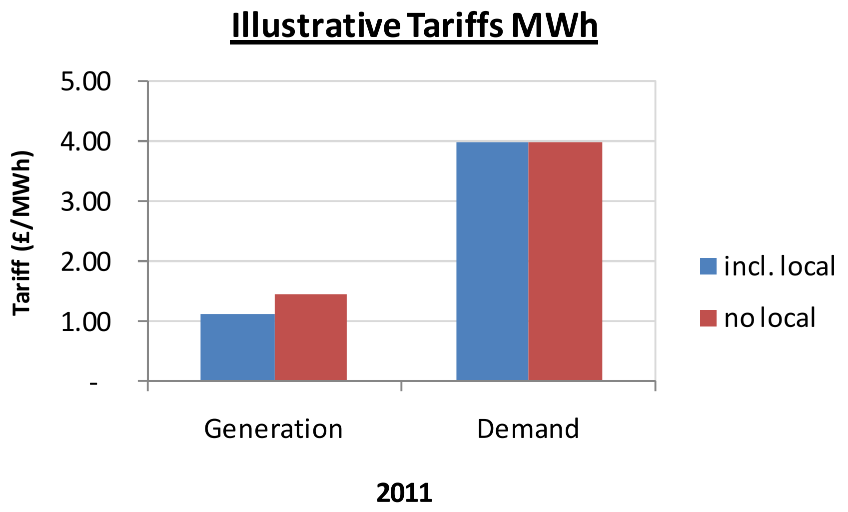


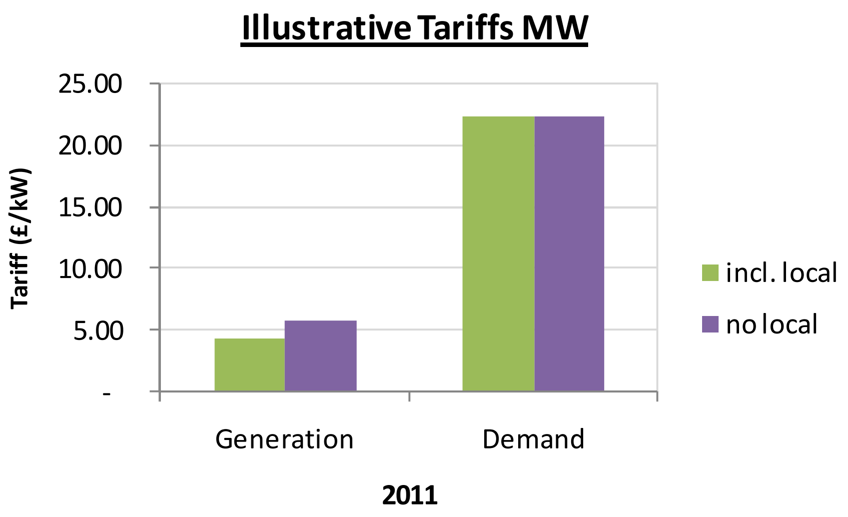


Indicative 2011/12 Postalised Tariffs

Several methodologies have been used to produce illustrative tariffs under a postalised system. These relate to options identified in Working Group discussions and are as follows;

- Theme 1 – Indicative tariffs are provided for a commodity (MWh) based tariff, and a capacity (MW) based tariff for generation and demand users
- Theme 2 – Indicative tariffs are provided for options with and without generation local charges
- Theme 3 – N/A
- Theme 4 - N/A
- Theme 5 – N/A
- Theme 6 – As status quo (no change until 2015)





Indicative 2011/12 Tariffs for ICRP variants

Two Working Group members provided a number of illustrative tariffs by varying key ICRP distance multipliers as part of the Working Group Theme 2 discussion (see section 5.35). For reference, these are provided below.

Indicative 2011/12 Tariffs with expansion factor of 1.0

Currently different circuit technologies and voltages have different expansion factors applied to reflect the relative incremental MWkm costs of these technologies against the standard of 400kV overhead line. Figure h and Figure i model wider tariffs assuming an expansion factor of 1.0 for all circuits. Figure h also shows the impact of this change to the expansion factor for wider elements of the generation tariff only, and also all tariff components including onshore and offshore local charges.

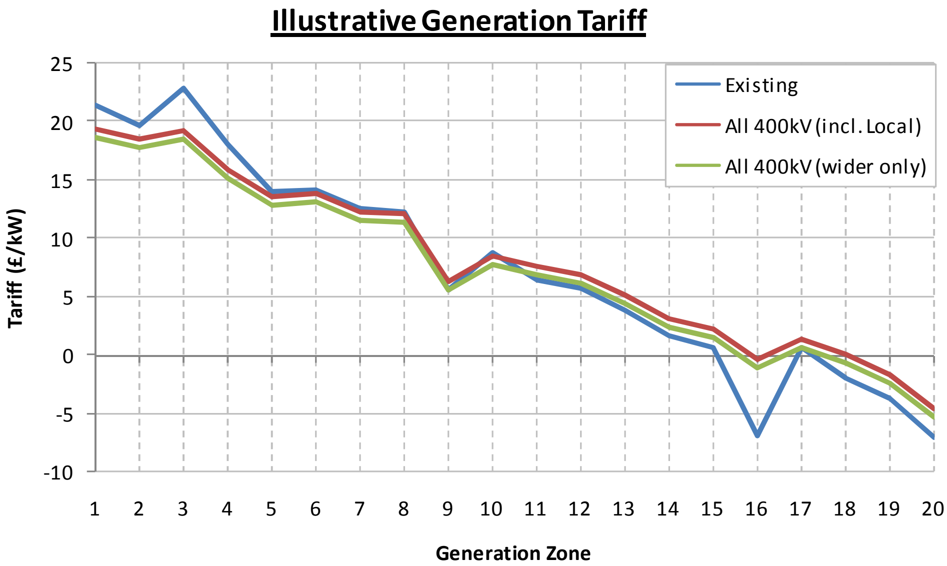


Figure h – 2011/12 wider generation tariffs with expansion factor of 1.0

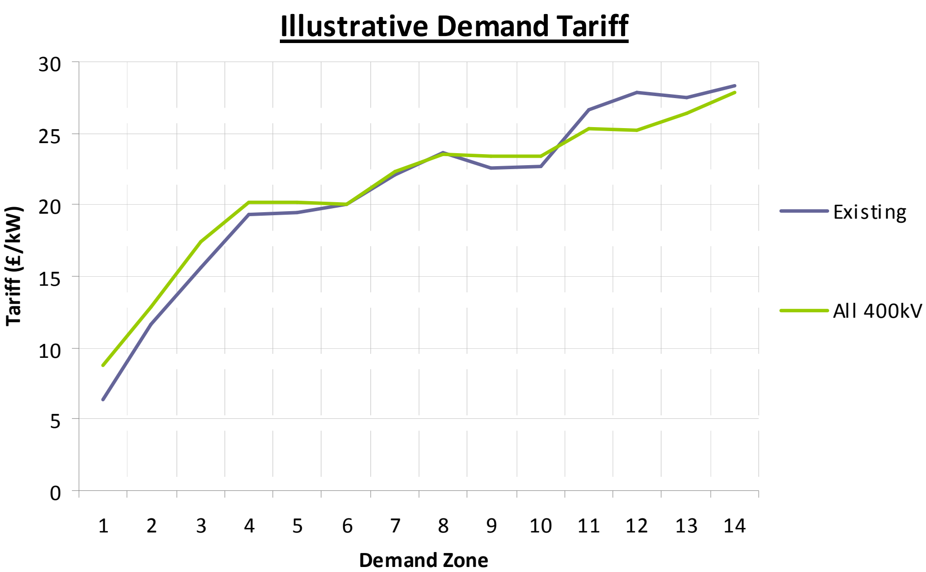


Figure i –2011/12 demand tariffs with expansion factor of 1.0

Indicative 2011/12 Tariffs with security factor of 1.0

Currently a global security factor is applied to of 1.8 is applied to all wider circuits in order to account for the level of redundancy build necessary to manage transmission system security.. This is discussed further in Theme 3. Figure j and ? model wider generation and demand tariffs assuming a security factor of 1.0 for all circuits. This could be seen as socialising the benefit of higher security levels.

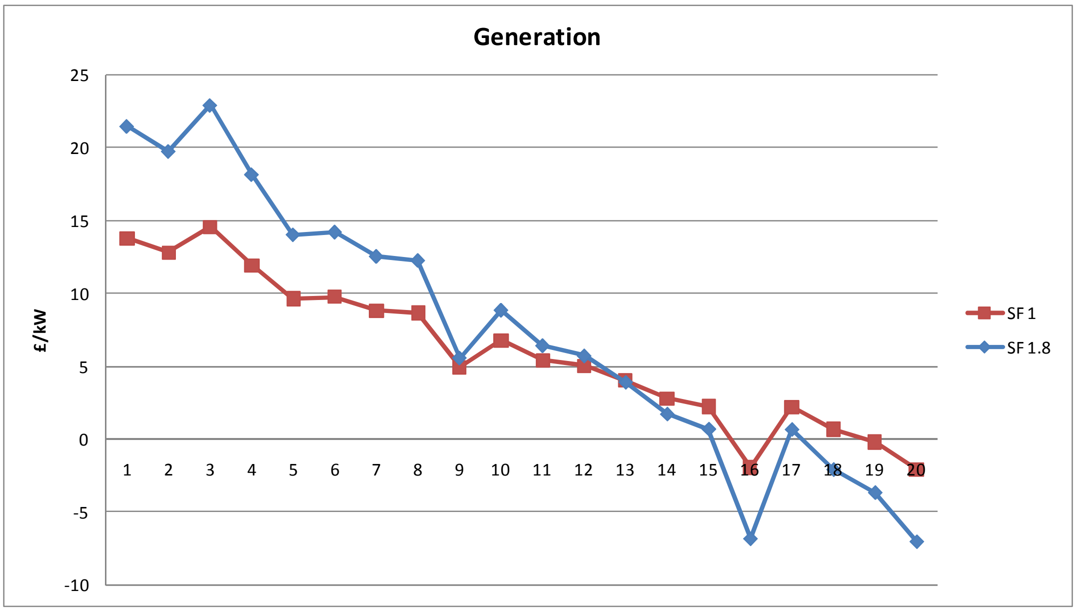


Figure j - 2011/12 wider generation tariffs, security factor of 1.0 compared to 1.8

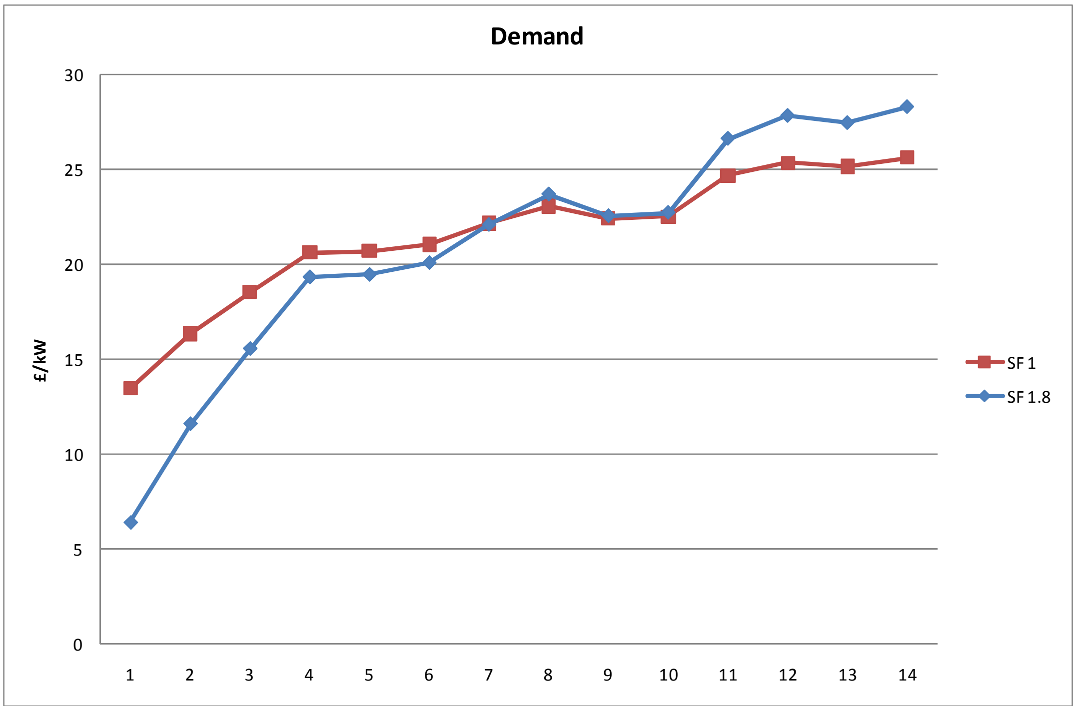


Figure k - 2011/12 demand tariffs, security factor of 1.0 compared to 1.8

Indicative 2011/12 Tariffs following alteration of generation zoning criteria

Currently generation zones are set to contain relevant nodes whose wider marginal costs (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

Figure I illustrates a possible change to this criteria, with wider generation tariffs re-zoned into the same 14 zones as demand. Practically this has been achieved by making the generation zone the same as the respective demand zone in National Grids transport and tariff model. This chart also shows the cumulative effect of setting expansion and security factors to 1.0.

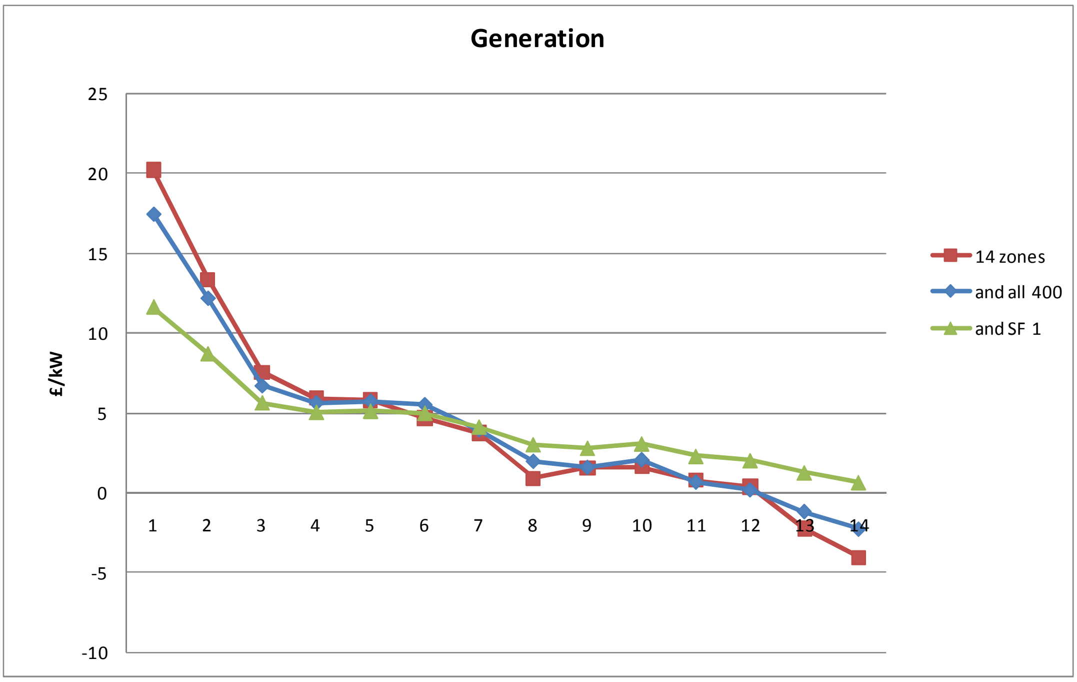


Figure I - 2011/12 wider generation tariffs, re-zoned into 14 demand zones

Annex 9 – Detailed Transitional Issues

The following annex provides more supporting detail to the discussions that have taken place between Working Group members regarding the subject of transitional issues. A significant proportion of this discussion has taken place via e-mail, and this annex seeks to consolidate this information into one document. The discussion has been summarised into the considerations of the three main affected parties; generators, suppliers, and end consumers.

There was a general discussion on recent debates on transitional issues. During CAP188 (Code Governance Review; Governance of Charging Methodologies) discussions, Industry parties agreed that, to provide greater certainty to the industry, an implementation date of 1st April should always be recommended as a default date for modifications to the charging methodologies. The only mention of using another implementation date was under "exceptional circumstances". This was explored further during the CMP195 (Code Governance Review post implementation clarifications) process, where exceptional circumstances were seen as being more to do with implementation related issues (such as IT or resource constraints), rather than a tool for delivering the early implementation of charging amendments;

Several options to smooth transition were discussed by the Working Group. These included;

a) Apply changes for all from 1st April 2013 this will allow a short time (1 month if decision made in February 2012) for users to decide to exit the system without charge by giving 1 years and 5 days notice. This would not allow sufficient time to negotiate any significant changes to contract terms prior to the notice date.
b) Apply changes for all from 1st April 2014 this will allow sufficient time for users to negotiate new project finance structures with their backers or exit the system.
c) Apply any changes immediately (1st April 2012) for new generation but delayed by 2 years (1st April 2014) for existing generation this would allow exiting generation to either exit the system or agree new commercial arrangement for a significant charge increase
d) Apply a "transitional relief" methodology for charges that change significantly (either reduce or increase) over 5 years in a similar way to Business Rate relief in Wales this will ensure that year on year changes are modest and allows efficient management of any increase.

Generator Considerations

Proposed TNUoS methodology changes could result in significant changes to generator charges. As decisions for power stations are made under the existing Regulatory regime, any changes could materially affect the economics of their operations. A low load factor southern generator of size 100MW in the extremes could move from receiving a TNUoS income of £700 k to paying a charge of £400k as shift of £1.1m/year or around £7m reduction in the values of a project. This is a material change in the fortunes of a generator who could well be financed on project finance. Similarly generation in Northern Scotland could receive significantly lower charges and resulting windfall gains.

There may also be negative effects on new entrants. Greater certainty over the level of future transmission charges will make it easier for new entrants to judge the commercial viability of their proposed investments. Greater uncertainty of future transmission charges as a result of hurried transitional arrangements might have a negative effect on the future development of generation capacity. This has the potential to create an investment hiatus. Transitional arrangements need to be sensitive to the needs of generation developers.

There is no reason to think that independent generators' TNUoS cost treatment is more likely to be fixed relative to large generators. However, the materiality of TNUoS cost increases is likely to be greater for independent generators as they will have less ability to absorb cost increases as their cash requirements are likely to be tighter relative to large generators. Moreover, the larger generation firms might be able to spread (and thus absorb) cost increases resulting from changes to the transmission charging arrangements across their portfolio of generation assets. It should be noted that the empirical example provided of the mid year tariff change in 2010/11 also had an adverse effect on independent generators.

Additionally the arrangements that currently apply allow generation the opportunity to avoid TNUoS charges through reduction of their TEC to zero, however if a user reduces its TEC to zero with less than 1 years and 5 days notice an additional charge of one year's TNUoS is applied. This charge is based on the existing TEC of the user. Given this requirement, it could be viewed that any required significant changes to the methodology should not be applied before 1st April 2013.

Contractural Considerations

There are a number of contracting methodologies that would need to be considered;

- Bilateral contracts with counterparties which may extend to two years ahead; these may be for individual power stations units, power stations or portfolio.
- STOR type contracts that vary between a few months and several years.
- Power Purchase Agreements that extend for the lifetime of the plant.

The treatment of transmission charging within these contracts will vary; in some the risk will be carried with the generator, in others it will reside with the counterparty.

All merchant generators (independent and vertically integrated) are likely to enter similar bilateral contracts in the wholesale market (standard GTMA T&Cs). The term of these trades will be limited by market liquidity (i.e. two years forward). Structured contracts/trades are more bespoke in nature, and will span multiple years (two years or more); it is not uncommon to have agreements of five years duration or more. Tolling contracts or off-take agreements can be longer still, depending on the type of generation investor e.g. a joint venture where two investors develop the plant, but where only one trades with the other having an off-take arrangement.

The problem for generators with a change in the transmission charging arrangements (and resulting changes in charges) relates to the treatment of TNUoS costs in these fixed contracts. If this element is treated as a cost 'pass through' or re-openers are available, then there is not a requirement for lengthy transitional arrangements. However, if TNUoS costs are treated as fixed then generators will find it difficult to pass through any variations in TNUoS charges and might be forced to absorb any cost increases (although it should be noted that any reductions in TNUoS charges will provide a net benefit to generators). GTMAs have no adjustment mechanism for TNUoS charge variations with any change borne by the disadvantaged party.

The implication for generation power purchase agreements depends on the length of the agreement. In the long term (15 years), standard practice is for the TNUoS charge to be passed on to the Power Purchaser as Project Financers typically would not wish to be exposed to unpredictable costs whose management is outside the control of the generator. In the medium term (bespoke generation specific contract for existing assets; i.e. not project finance; 3 to 15 years out) the normal practice is that the risk of a TNUoS charge change is negotiated by counter-parties, similar to many other potentially varying costs/rewards. In the short term (standard NETA /BETTA trade structure for power trades up to 3 years out) it is likely that changes cannot be passed on given that trades are transacted at a virtual point that doesn't recognise the physical location of the generator. Given this, it is not likely that changes to TNUoS would affect the terms of a GTMA trade. There may be a clause which could allow the contract to be renegotiated if a TNUoS change was seen to substantially alter the commercial terms for the generation market as a whole.

Supplier Considerations

Supply businesses are arguably more vulnerable than generators to potential charge movements caused by changes to the methodology or the amount of allowable revenue to be recovered. Any significant charging change has to be handled carefully so as to avoid increasing the cost of serving retail customers and detrimentally affecting competition in the retail sector.

Retail margins are low; therefore, even a modest level of uncertainty in the cost base for suppliers can translate into a significant risk. The impact on suppliers will depend on which customers are affected. Domestic customers typically are on tariffs which can be changed periodically, although competitive pressure limits the extent to which this is possible. Retailers want to provide a good service and competitive products and will absorb certain cost changes rather than pass them on.

Business customers will be on contracts largely signed up during the main contracting rounds. The terms under which these business customers are contracted can vary in nature. Some of the largest customers opt for more of a pass through approach for costs in order to reduce the associated risk management costs of serving them. Other business customers are increasingly requesting fixed price contracts however. Perhaps more than 50% of the volume currently sold in this sector is through fixed contracts that are longer than a year; typically 2 to 3 years. The two main contract rounds take place for customers signing up deals starting in October and April respectively, with the October round being the larger of the two. For the October round quoting typically starts around June/July; for the April round quoting really picks up in January.

It is the main contracting rounds which potentially pose the main challenge for transition. The transitional arrangements will need to take into account the timetable for quoting customers for the specific rounds, as well as the extent to which suppliers and customers could be exposed through longer term fixed price contracts. The only way to avoid any exposure would be to have a three year notice period to allow such fixed contracts to complete. However, understanding that this may not be realistic, shorter timescales than this would at least partially relieve the situation, not least because not all contracts would run for three years. It is also likely that suppliers will be reluctant to enter into future fixed deals due to the risk that they already perceive as coming from Project Transmit, which may mitigate the situation further.

Independent suppliers that operate in the I&C market are likely to have a large proportion of their customer base contracted to fix term deals, usually between two or three years duration, although they can be as long as five years. The question is whether transmission related costs are treated as fixed or a pass through item. If the TNUoS cost is fixed then suppliers will have to absorb some of the cost increases resulting from changes to transmission charges (although it should be noted that any reductions in TNUoS charges will provide a net benefit to suppliers).

In the domestic market all suppliers have to provide customers with at least 30 calendar days notice before making unilateral adverse variations to their customers' contracts. So there is greater ability to pass through material cost variations, but with a minimum one month delay. However the number of fixed price contracts is increasing in the domestic market (some fixed up to 2015) making unpredictable network charges a greater concern for domestic suppliers.

There is no reason to think that independent suppliers' TNUoS cost treatment is more likely to be fixed relative to incumbent suppliers. However, the materiality of TNUoS cost increases is likely to be greater for independent suppliers as they will have less ability to absorb cost increases as their cash requirements are likely to be tighter relative to incumbent suppliers. Furthermore, independent suppliers (both I&C and domestic) usually have a customer base that is concentrated in a particular geographic location rather than a widely dispersed customer base relative to incumbent suppliers (although they too will have 'home markets' where there presence is stronger, with the exception of British Gas). For independent suppliers, this regional concentration will make it more difficult for them to 'net off' TNUoS charge increases and decreases in different zones across their customer base. Therefore independent suppliers are more likely to face a disproportionate effect of a change in the transmission charging arrangements as they are likely to face a smaller quantity of tariff changes compared to incumbent suppliers.

Furthermore, it is felt that the proportion of independent suppliers' customers that are termed 'active' (have a greater propensity to switch) will be greater than the proportion held by incumbent suppliers. Following this incumbent suppliers will have a greater proportion of 'sticky' customers (that have a smaller propensity to switch) which means that incumbent suppliers are in a better position to pass through differential cost increases to customers with a more limited effect of their competitive position relative to independent suppliers.

What is clear though is that an April 2012 implementation of changes for demand customers would maximise the impact on suppliers. This will likely have cost to serve implications which may well affect customers; additionally different suppliers will be able to deal with this disruption to different extents. Therefore, an immediate transition could have a detrimental impact on competition.

End Consumer Considerations

It is often stated that consumers prefer to have stable prices rather than ones that are constantly varying. If this is the case then a smoothed transition is likely to mitigate the degree of variation in customers' bills. Of more concern to end consumers is to avoid unnecessary risk premia. As regulatory uncertainty cannot be 'hedged' using market mechanisms, market participants (both generators and suppliers) might opt to apply a risk premium to their prices to insure against the risk of cost increases resulting from regulatory decisions. Such mechanisms are quite crude in terms of their accuracy and thus cost reflectivity. Therefore transitional arrangements should endeavour to avoid the application of this risk premia, an unnecessary cost consumers should not have to pay.