CONSULTATION DOCUMENT

GB ECM-18

Locational BSUoS Charging Methodology

Re Issue - 23 March 2009

Table of Contents

1 Executive summary

On the 17th of February 2009 Ofgem wrote to National Grid requesting that it conduct an urgent review of its commercial and charging arrangements for access to the GB Transmission system, and to explore alternative arrangements to manage the cost of constraints to ensure that costs are recovered on an equitable basis from customers, suppliers and generators.

Constraint costs have increased from £70m in 2007/08 to a forecast of £238m in 2008/09 and £258m in 2009/10. As Ofgem highlights in its letter "A significant proportion of these constraints costs arise as a result of available transmission capacity shortages, relative to transmission entry capacity rights sold to generators in Scotland (and to a lesser extent England and Wales)".

National Grid believes that the commercial and charging arrangements it has in place fully meet its obligations and objectives, but in response to this request we have undertaken an assessment of the current BSUoS charging arrangements and have determined that there is merit in exploring whether an alternative methodology might better facilitate the applicable charging objectives.

A significant consideration in our decision to raise this consultation is the difference in the way the Long Run cost of access and the Short Run cost of access is targeted towards generators.

The Short Run cost of access is not targeted towards the parties that cause that cost to be incurred. The existing charging arrangements largely assume that the System is compliant. Under these conditions the system is planned and developed to provide a specific level of security for demand and to optimise long term investments with the potential short term costs. Along with an 'invest and connect' policy, this ensures that short term costs are efficient with respect to transmission investment. However, given the over allocation of rights, associated with BETTA implementation, the short term costs are potentially inefficient with respect to the longer term charge. As such, parties are at risk of not being able to make economically informed decisions as to the efficiency of their generation output decisions.

The time frame in which National Grid has been asked to assess the merits of changes to the charging methodology has dictated the scope and breadth of the proposals it has been able to present in this consultation. To that end, the proposals presented in this consultation represent a potential incremental improvement to the current arrangements but also indicate the intention to explore further improvements beyond that which may be achieved by this proposal.

Locational BSUoS charging reflects a considerable departure from the current "postage stamp" regime. To that end, National Grid is keen to ascertain parties' views as to the benefits and consequences of this proposed change.

2 Introduction

National Grid is obliged under its Transmission Licence:

(i) to make revisions to the Charging Statements in order that the information set out in the statements shall continue to be accurate in all material respects;

(ii) to keep the Use of System charging methodology at all times under review; and

(iii) to make such modifications of the Use of System charging methodology as may be requisite for the purpose of better achieving the relevant objectives, which are:

(a) to facilitate effective competition in the generation and supply of electricity and (so far as is consistent therewith) to facilitate competition in the sale, distribution and purchase of electricity;

(b) to result 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; and

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

The purpose of this consultation document is to describe an alternative charging methodology with a view to better meeting the relevant Transmission Licence objectives set out above, and invite industry views on the options presented.

3 Background

On the 17th of February 2009 Ofgem wrote to National Grid requesting that it conduct an urgent review of its commercial and charging arrangements for access to the GB Transmission system and to explore alternative arrangements to manage the cost of constraints to ensure that costs are recovered on an equitable basis from customers, suppliers and generators.

Constraint costs have increased from £70m in 2007/08 to a forecast of £238m in 2008/09 and £253m in 2009/10. As Ofgem highlights in its letter "A significant proportion of these constraints costs arise as a result of available transmission capacity shortages, relative to transmission entry capacity rights sold to generators in Scotland (and to a lesser extent England and Wales)".

Prior to the introduction of BETTA, the commercial availability of transmission capacity between the transmission systems of Scotland and England & Wales (E&W) was limited to the ability of the physical transmission capacity to accommodate that energy transfer.

The introduction of BETTA removed this limit and parties who had acquired internal Scottish access rights for existing, or soon to be commissioned, generation had these rights transferred into GB access rights under the CUSC.

However, the physical capability of the interconnection between the E&W and Scottish systems could not accommodate this new commercial requirement. As a result, this boundary, known as the Cheviot boundary, did not (and does not) meet the requirements of the Security and Quality of Supply Standards (GBSQSS). As such, derogation was sought by, and was granted to, the respective Transmission Owners for non-compliance with GBSQSS.

This lack of compliance causes significant transmission constraints to occur across this boundary. In response to such constraints, the Great Britain System Operator ("the SO") contracts for commercial services to manage these constraints and this constraint management activity incurs considerable cost for the industry.

In response to both this and the desire to connect significant amounts of renewable generation in Scotland, the relevant transmission companies have embarked on a programme of reinforcement and expansion that goes some way to alleviate this transmission capacity shortfall. However, on the Cheviot boundary the differential between the level of available transmission capacity and the level required to accommodate those parties that require connection to the transmission system is forecast to grow next year. Therefore, the cost associated with managing this disequilibrium is also likely to increase.

The costs associated with managing locational transmission capacity shortages are allocated to industry participants through the Balancing Services Use of System (BSUoS) charge. Currently, the entirety of this charge is allocated on a postage stamp basis. As such, all generators and suppliers, regardless of their location, pay this charge based on their relative metered use of the system in each half hour.

Given the continuing increase in costs associated with managing constraints across, what is at present, the only non-compliant derogated boundary (Cheviot) it is prudent

to consider whether the current methodology for allocating costs will lead to the most efficient outcome for the market and hence the best price for consumers.

Against this background the SO has raised this charging consultation to determine if there is a more efficient manner in which these BSUoS costs can be assigned.

3.1 Rationale for Changing to a Locational BSUoS Charge

Transmission Network Use of System (TNUoS) charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) function of the transmission businesses of each transmission licensee.

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

This TNUoS signal is based on the understanding that the transmission system is compliant with the requirements set down in the GBSQSS. For a transmission system that meets the GBSQSS, the level of transmission capacity built has been assessed against the systems ability to accommodate the expected level of energy flow between electricity producers and electricity consumers across the winter peak demand.

Any further reinforcement is determined on a cost benefit assessment. If the system is heavily constrained, then reinforcement is considered when the enduring savings in the Short Run cost (SRMC) of access, i.e. the potential costs associated with providing commercially firm access in System Operation timescales, is forecast to be greater than the Long Run Marginal Cost (LRMC); the cost of reinforcing the system.

However, if a transmission boundary is non-compliant (as is the case for the Cheviot boundary) it will not have been reinforced to a level to accommodate the generation capacity that sits behind it. In such circumstances, this generations' commercial access will not be accommodated through physical transmission assets, but will be accommodated through short term constraint management activity.

This constraint cost activity is undertaken by the SO function and the costs are apportioned to the industry through the BSUoS charge. However, the BSUoS charge is not targeted at parties that cause these Short Run costs to be incurred. Therefore, whilst TNUoS reflects the Long Run cost of access (LRMC) on a compliant network, BSUoS does not currently reflect the short term cost of access in a non compliant network. Therefore, the combination of the BSUoS and TNUoS will understate the full cost. A flat BSUoS charge will not be able to provide generation with any signal as to whether it is efficient for them to inject energy into particular locations on the transmission system at different times under the non compliant situation.

In such circumstances, the marginal cost of generation will not be accurately reflected in the merit order pricing of generation BMU and the market will not clear as efficiently. This could lead to an additional cost to the end consumer.

4 Options

4.1 Summary

Proposed Locational BSUoS charging methodology:

- BSUoS charges will be amended to have two component parts;
  - A targeted locational element reflecting the costs of constraints incurred through derogated boundary non compliance; and
  - A residual element incorporating the remaining costs.

- The targeted locational element is allocated to all BMUs located behind the derogated boundary who are exporting in the period in question or had ceased generating as part of the SO's constraint management process;

- The residual element is charged to all BMU who normally incur a BSUoS charge; and

- A TNUoS rebate will be calculated based on the level of TEC which is in excess of that which could be accommodated if the boundary was compliant under the GBSQSS.

4.2 Definition of Constraints

This consultation proposes a methodology to target the costs of constraints attributable to the derogated non compliant boundary onto those generators that are located behind that boundary and thus contribute to the constraint. A description of a constraint is set out in Appendix 1.

4.3 Determination of a non Compliant Boundary

A transmission boundary is deemed as compliant if it meets all the planning criteria for the Main Interconnected Transmission System (MITS) as set down in chapter 4 of the GBSQSS.

A non compliant derogated boundary is a boundary that does not meet the criteria described above but has been granted derogation against the need to be compliant against the GBSQSS by the electricity regulator.

In March 2007, Ofgem issued a letter granting a derogation from Standard Condition C17 of the electricity transmission licence to relieve NGET of its obligation to comply with the main interconnected transmission system criteria in paragraphs 4.1 – 4.13 of the GBSQSS, Version 1.0 (the "GBSQSS").

The derogation relates to the circuits between Eccles and Stella West, Strathaven and Harker and relevant 132kV circuits from Galashiels. This boundary is defined as the B6 in the National Grid Seven Year Statement and is often referred to as the Cheviot Boundary. Currently this is the only boundary which is non compliant and has a derogation

4.4 Determination of constraint volume incurred due to boundary non compliance.

Although a boundary is non-compliant it would not be correct to assume that all constraints that occur against this boundary would be due to that reason. Investment decisions on compliant boundaries are in part undertaken on a cost benefit basis. These parts of the system also require management of constraints from time to time as there is an assumed level of diversity in generation and to invest on the basis of all connected generation operating concurrently would not be efficient or economic. Therefore it is important to determine the proportion of constraints that are incurred due to the boundary being non compliant as opposed to those that could be expected if the boundary was compliant.

Therefore, any actions taken to accommodate the commercial access requirements of generation behind this boundary, that could have been accommodated if the boundary had been compliant, but can currently only be accommodated by SO constraint management activity, would be due to the lack of available transmission capacity. This lack of compliant capacity can be translated into the MWh volume of actions taken to manage the constraint.

Therefore, the volume of constraints that are incurred due to the boundary being non compliant can be calculated as:

Minimum (Required Capability – Actual Capability, Volume of Constraints taken to manage the non compliant boundary)

The proposed methodology by which the values of the required capability and the actual capability are derived are set out in Appendix 2.

4.5 Level of constraint management costs incurred due to boundary non compliance.

National Grid, as the SO, has developed an internal business process that allows it to track the costs associated with different aspects of the management of the transmission system. These SO functions include energy balancing, maintaining reserve levels and resolving system constraints.

This methodology has been evolved to accommodate the post event identification of both constraint costs incurred due to boundary non compliance and those that would have ordinarily occurred on a compliant system.

The main points of this process are to assess the following.

- Whether an action is required to buy or sell energy, or to take another form of action such as arming an inter-trip, to resolve a constraint?,
- Assessment of the cost of such action against a similar action that may have been taken outside of the constraint zone;
- Depending on the length and direction of the market would this action necessitate the need to resolve an energy position (either buy or sell)?
- Does this action sterilise reserve that has to be replaced by procuring it in an unconstrained part of the system?

A detailed explanation of the costing methodology is set out in the accompanying note entitled "Constraint Costing Methodology (Locational BSUoS)"

4.6 Impact on BSUoS Charges from the introduction of a locational element

Currently a Users BSUoS charge is calculated based on its proportion of the total BMU metered volume (QM) (MWh) for each settlement period multiplied by the BSUoS tariff applicable for that settlement period.

Under this proposal there will be two elements to the BSUoS charge for a User:

1. A Targeted Constraint Charge (TCC) that will affect exporting BMU's within a geographical zone linked to a non-compliant boundary. In the case of the B6 boundary this would incorporate generation zones 1 to 8. This targeted constraint charge is calculated based on the User's Meter Adjusted Volume as a proportion of total constraint volume multiplied by the cost of constraints arising from non-compliance with the GBSQSS; and

2. A Residual BSUoS Charge (BSUoSTOTR) that is calculated based on the User's proportion of the Total BMU Metered Volume (QM) (MWh) for each settlement period multiplied by the Residual BSUoS tariffs, this being derived from the Total BSUoS Charge less the cost of constraints arising from non-compliance with the GBSQSS.

The adjusted MW is the load level that parties would have been generating at if the non compliant boundary was not constrained This MW adjusted value (**$QMadj_{ij}$**) will be derived post event and be calculated as the BMU final metered position adjusted to incorporate any pre or post gate closure actions that the SO may have taken on that BMU.

It is more equitable to allocate the costs on this basis than on a simple BMU metered position, as under a simple metered position there may be occasions where, for example, BMU (A), has caused a constraint through its forecast generation load level. The SO subsequently takes bids on BMU (A) to resolve this issue and, due to the market length in the period, the SO is also required to take replacement energy actions. When this cost is allocated to all the BMU behind the constrained boundary no cost will be allocated to BMU (A) against its metered output even though it contributed towards the need to take constraint management actions in the first place.

A full description of adjusted MW and the changes to the BSUoS charges are set out in Appendix 3.

4.7 TNUoS & BSUoS Interaction

TNUoS represents a proxy for the Long Run cost of access in a compliant part of the transmission network. Under this proposal Locational BSUoS would represent a proxy for the Short Run cost of access in a non compliant part of the network.

However, at present all generation parties that connect to the transmission system are exposed to TNUoS charges regardless of the level of network compliance. Under a locational scheme these parties would be charged for both the Long Run and Short

Run costs of accessing the transmission system. We do not believe this is appropriate.

The locational TNUoS charging element will only be charged to that proportion of TEC that would be available on a compliant system. Therefore, all parties liable for generation TNUoS behind the non compliant boundary will have their locational TEC tariff scaled back to reflect the fact that the part of the network at which they are connected to is non compliant.

Since the energy flows across the system have not changed, the LRMC in most zones across the transmission system are still correct. Therefore, it is not necessary to recalculate the zonal differentials in compliant zones. The amended TNUoS methodology is designed to reflect the fact that parties in non compliant zones will be effectively paying the Short Run cost of access for that proportion of their access that cannot be accommodated under a compliant network.

In the event that this methodology endures for more than one year, National Grid proposes to recalculate the level of non compliance on an annual basis utilising the most recent data provided in the Seven Year Statement.

The methodology by which generation locational TNUoS charges in non compliant boundaries are discounted is set out in Appendix 4.

4.8 Information Provision

The rationale behind an ex post methodology is that generating BMU will be better informed of their costs of generation and so be able to make economically informed decisions in relation to their generation strategies.

In essence, during periods of constraints, parties within non compliant zones will be incentivised to assess whether it is still efficient to run, or to reduce load within the constraint zone and buy replacement energy in the open market.

If market information is effective this will lead parties to buy energy in zones of the network that are not constrained. This replacement energy will not be exposed to Locational BSUoS and should have a comparative advantage in the market.

We recognise that generation parties will continually evolve their energy account position from years ahead down to gate closure. This position will be influenced by changes in generation outages, input costs, forward market price and demand.

As such, National Grid recognises the need to provide information to the market as early as possible as to what volume of constraints are likely to bite and the relative impact that this will have on BSUoS.

In relation to Locational BSUoS, the important consideration for generation is the likelihood with which the SO will undertake actions to resolve boundary non compliance. This is a function of demand and generation in Scotland and the capability of the interconnection circuits across the relevant boundary.

To that end, National Grid will provide a forecast of generation, demand and the capability of the boundary at a number of lead times throughout the year. An indication of likely constraint costs may also be published, although as costs will be

based on a forecast of generation load and price submission behaviour they would be indicative in nature.

In the event that CAP170 is approved by the authority, a proportion of the constraint volume that may arise due to the boundary non compliance, is likely to be accommodated by an operational inter-trip.

National Grid anticipates making the following information available:

- At year ahead: Publication of forecast weekly peak demand, forecast generation and likely boundary capability;
- At 2/3 weeks ahead: Publication of forecast weekly peak demand, forecast generation and likely boundary capability; and
- At day ahead: Publication of forecast demand, forecast generation and the updated boundary capability including the proportion of the capability made available through the arming of an operational inter trip.

The rationale for this is that parties will be able to make informed decisions as to the probability that the boundary will become constrained and adapt their generation behaviour in line with their risk appetite and ability to absorb the likely constraint costs.

4.9 Timeframe for Publication of Locational BSUoS element

National Grid appreciates that the outturn Locational BSUoS element is another important component in determining the load level decisions of generators. To that end we aim to provide an indicative value of the locational BSUoS element on working day+2 on a reasonable endeavours basis.

4.10 Implementation

Changes to the TNUoS tariffs and the BSUoS charging principles need to be coordinated. We propose that the implementation date be the first date of the subsequent month following the Authority's decision as long as that decision is made with five working days notice. This will allow sufficient time to implement all the required changes

4.11Forecast of Potential Volume & Cost Implications (20009/10)

The initial forecast MW level of non compliance on the B6 boundary is 1813 MW based upon the proposed methodology set out in appendix 2. The cost of the most expensive actions up to this volume are deemed to be due to the boundary being non compliant (i.e. if the boundary was compliant such actions would not be necessary).

The forecast assessment of the level of costs associated with this volume is between £70 and £120 million (this level of costs will be influenced by any decision regarding the current CAP 170 operation inter trip proposal).

The forecast level of TNUoS rebate that generating BMU behind the B6 boundary will receive is approximately £22 million.

5 National Grid – initial views

Ofgem has indicated that it would like to see any proposals arising from the conclusions of our review to be consulted upon, and capable of implementation, as early as possible.

The time frame in which National Grid has been asked to assess changes to the charging methodology has dictated the scope and breadth of the proposals it has been able to present in this consultation.

The current locational charging proposal is limited to generating BMU but National Grid recognises that it may be appropriate at some point to further explore the effects of other parties' behaviours on the level of constraint management actions undertaken by the SO. Specifically it may be prudent to explore the impact that distributed generation has on constraints and whether it may be more economically efficient to introduce some form of locational signal to better reflect the constraint costs these parties can cause. As such, National Grid will continue to explore these issues during the course of 2009.

The locational element of the proposed BSUoS methodology is a £/MWh price based on the principle of an average price cost recovery. This is deemed a pragmatic methodology for assigning costs given the limited time available in developing this proposal. However, we believe that if this Locational BSUoS methodology became an enduring solution it would be appropriate to revisit the question of average or marginal prices in light of any changes bourn out of the Transmission Access Review. National Grid is of the view that marginal signals ultimately lead to a more economically efficient utilisation of the transmission system.

We believe this methodology is able to accommodate both a single, and a number of non compliant, derogated, boundaries. If this proposal were implemented, National Grid would continue to consider any improvements that could be made to the methodology if, for example, a significant number boundaries were granted derogation due to becoming non compliant..

Whilst National Grid is of the opinion that its existing commercial and charging arrangements fully meet its obligations and objectives, the recent escalation in constraint costs indicate that it is appropriate to consider the targeting of constraint costs caused by boundary non compliance on a locational basis.

Under a Locational BSUoS regime the charge would act as a signal to allow generation to make economically efficient choices in determining the relative BMU specific costs of entering the market in any particular period.

Therefore, the methodology proposed in this consultation for determining the locational element of the BSUoS charge is a potential incremental improvement on the current methodology.

5.1 Assessment of options against relevant objectives:

Facilitating Competition

In that Locational BSuoS could be argued to be more appropriately targeting the costs of exporting BMU then this must lead to a generation merit order that more accurately reflects the BMU specific marginal cost of generation. This in turn must lead to a more efficiently clearing energy market.

Cost-reflectivity

Locational TNUoS reflects the Long Run marginal cost of reinforcing the system and therefore is reflective of the costs of access on a complaint system as determined under the GBSQSS. The additional costs associated with a non compliant boundary will not be reflected in TNUoS. Those additional costs will be reflected in the proposed Locational BSUoS methodology and as such we believe the overall proposed charge will be more cost reflective and better meet the applicable objectives.

Developments in the transmission business

The locational element of the TNUoS charge dos not accurately reflect the cost of accessing the transmission system in zones which incorporate non compliant derogated boundaries. By introducing a charging signal that attempts to more fully signal this cost, partiers will be better informed as to the relative costs the transmission owners incur in connecting them at different locations across the system. This should improve the efficiency of transmission investment signals.

6 Responses

Comments and views are invited on all of the issues raised in this consultation document. To ensure that your comments and views are considered as part of National Grid's forthcoming consultation document, responses must be received by close of business on the **20th April 2009**.

Comments are particularly welcome regarding:

- What impact do you feel these proposals will make on constraint costs?
- Do you agree with the proposal in that the Locational BSUoS element is only applied to generation?
- Do you agree that this proposal should be implemented without addressing the method of targeting distributed generation?
- Do you agree the timing for Locational BSUoS is appropriate given the imminent proposed changes from Transmission Access Reform?
- What do you see as to the benefits and/or consequences of this proposed change (e.g. in respect of new generation connecting)?
- Do you agree with National Grid's assessment of this proposal against our relevant licence objectives?
- Do you agree with the methodology to determine level of Non Compliance on a derogated boundary, if not what improvements could be made?
- Do you believe the costs of replacing sterilised headroom should be allocated in the Locational BSUoS charge?

If you wish to provide comments on this pre-consultation document, responses are preferred via email to: balancingservices@uk.ngrid.com

Alternatively, Users can send their comments in writing, addressed to:

Rob Smith
Transmission Commercial
National Grid Electricity Transmission Ltd
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

If you have further queries, please do not hesitate to contact Rob Smith on 01926 654076.

7 Appendices

Appendix 1: Definition of constraints

The definition of constraints within this proposal are defined as any limit on the ability of the GB transmission system, or any part of it, to transmit the power supplied onto the GB transmission system to the location where the demand for that power is situated which arises as a result of:

1. The thermal rating of one or more high voltage electric lines forming part of the GB transmission system being exceeded;

2. The inability to maintain voltages on the GB transmission system within limits prescribed in the GB Security and Quality of Supply Standard referred to in condition C17 (Transmission system security standard and quality of service) or any other provision of the Act, this licence or any other requirement of law; or

3. Limitations to ensure the transient and dynamic stability of electrical plant, equipment and systems directly or indirectly connected to the GB transmission system being breached.

Appendix 2: Methodology to determine level of Non Compliance

This appendix describes the methodology to determine level of non compliance on a derogated boundary. The Cheviot boundary is, at present, the only non-compliant boundary. The example of this boundary is used within appendix 2 to illustrate this methodology.

Determination of Derogated Boundary

In March 2007, Ofgem issued a letter granting a derogation from Standard Condition C17 of the electricity transmission licence to relieve NGET of its obligation to comply with the main interconnected transmission system criteria in paragraphs 4.1 – 4.13 of the GB Security and Quality of Supply Standard, Version 1.0 (the "GBSQSS").

The derogation relates to the circuits between Eccles and Stella West, Strathaven and Harker and relevant 132kV circuits from Galashiels (the "Cheviot Boundary Circuits")

Method of Determining required capability of transmission boundary

Section 4.3 of the GBSQSS states:

4.3 In planning the MITS, this Standard is met if the design satisfies the minimum deterministic criteria detailed in paragraphs 4.4 to 4.12. It is permissible to design to standards higher than those set out in paragraphs 4.4 to 4.12 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix E .

The deterministic criteria that are used to establish the minimum required capability of a boundary are set out in sections 4.4 to 4.12 of the GBSQSS. These criteria, including the interconnection allowance, are applied to the B6 "Cheviot" boundary.

The required transfer capability of the B6 boundary is then established as follows:

- System conditions (i.e. network demand, network topology) are set to represent ACS winter conditions with an intact network**.**

- Power flows are first set to those arising from the ***planned transfer conditions***, determined according to Appendix C of the GBSQSS, and summarised as follows:

    - GB Generation is selected via a ranking order to meet GB ACS peak demand + losses + plant margin. In the ranking order, power stations are ranked in order of likely operation at times of ACS peak demand. Power stations that are considered least likely to operate are progressively removed and treated as 'non-contributory' until the remaining 'contributory' plant results in a GB plant margin of 20%;

      (Note that in this analysis, wind generation is assumed at 40% connected capacity such that sufficient conventional plant is deemed 'contributory' to maintain adequate plant margins with respect to the variability of wind generation);

- The registered capacity of each selected 'contributory' generator is first scaled by availability (A_T) factors. The availability factors will be appropriate to each generation type; and

- The resulting generator outputs are scaled nationally to meet the ACS demand + losses - imports from external systems (France and Ireland), and this represents the ***planned transfer*** ('P_T') ***conditions.***

- Given that, of the two parts of the GB transmission system separated by the B6 boundary, the smaller (Scotland) contains more than 1500MW of demand at the time of ACS peak demand, Appendix D of the GBSQSS states that an **interconnector allowance** must be added to the boundary flow under ***planned transfer conditions*** to determine the required capability of the boundary.

    - Interconnector allowance ('IA') is calculated (using the formulae in Appendix D of GBSQSS) and equates to approximately 1200MW for B6.

- The minimum required boundary capability is then set to be:

    - PT + IA (for N-1 contingencies)
    - PT + 0.5 IA (for all other contingencies).

Capability of B6 Boundary: required, existing and derogated capacity shortfall.

Required capability

The B6 boundary flows, under ***planned transfer conditions,*** for forthcoming years, are published in the Seven year Statement.

	BOUNDARY	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
B6E	SPT - NGET (EXPORT)							
	Effective Generation	8705	9544	9941	10072	10827	10947	11234
	Demand	6062	6131	6182	6210	6271	6331	6421
	Planned Transfer	2643	3413	3759	3862	4556	4616	4813

Extract from Figure 9.T6, chapter 8 of 2008 Seven Year Statement

The minimum required capability of B6 is determined by adding the appropriate interconnector allowance to the transfer under ***planned transfer conditions.***

Under intact conditions, the most limiting of the secured events listed in section 4.6 of the GBSQSS can be readily identified to be a double circuit fault on the supergrid on the boundary. For a double circuit fault, half the interconnector allowance should be added to the planned transfer conditions to determine the required transfer capability.

As a result, the required transfer capability of B6 would be:

3413 + (0.5*1200) = 4013MW for 2009/10.

(Note - *these figures for 09/10 are based on information issued in the latest Seven Year Statement, published in May 2008. The figures will be updated in the next version of the Seven Year Statement, due to be published in May 2009.)*

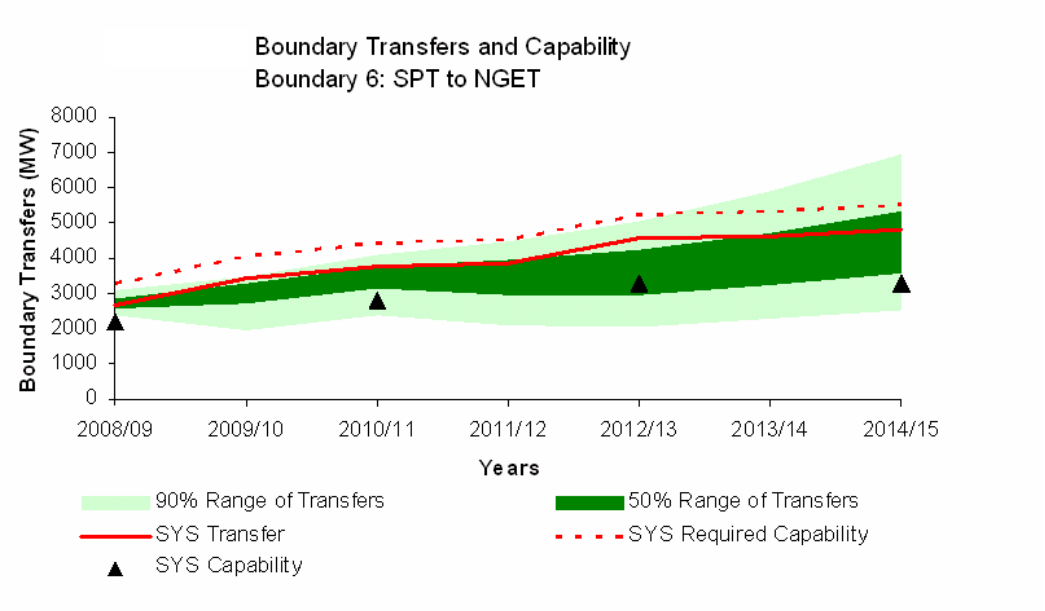
Existing Capability

Assessment of the B6 boundary under intact conditions reveals that the current capability of the system is 2200MW, as published in the Seven Year Statement.

Volume of derogated capacity shortfall

From the above numbers it can be seen that the derogated B6 boundary is deficient in capacity by 1813MW.

The current and required capabilities for the B6 boundary and the shortfall between them, is illustrated graphically in the Seven Year Statement. This is included for reference below.



Extract from Figure 8.B6, chapter 8 of 2008 Seven Year Statement

Volume of constraints to be included within locational BSUoS Element

The most expensive 1813MW of bids and any consequential balancing actions taken to manage the derogated B6 boundary (i.e. the difference between required boundary capability to meet GBSQSS and the current capability) should be charged to generators behind the boundary as a locational element to their BSUoS charge. If the volume of constraints taken to manage the B6 boundary is less than or equal to1813 MW, the cost of this volume will be allocated to the locational BSUoS charge.

How does the Boundary Non Compliance Volume translate into non compliant level of TEC?

Under the deterministic criteria, in order to achieve full compliance with the GBSQSS (in absence of the derogation described in section 1), the existing B6 boundary capability of 2200MW would, given the current level of registered generation in the GBSQSS, support a connected TEC capacity approximately 2250MW or (20%) less than is currently connected.

This translation of a boundary capability shortfall into a level TEC is utilised to calculate the level of TNUoS rebate that generators located behind the non compliant boundary will receive.

Appendix 3: Proposed BSUoS Charge elements

Currently a Users BSUoS charge is calculated based on its proportion of the Total BMU Metered Volume (QM) (MWh) for each settlement period multiplied by the BSUoS tariff applicable for that settlement period.

Under this proposal there will be two elements to the BSUoS Charge for a User:

1. A Targeted Constraint Charge (TCC) that will affect exporting BMU's within a geographical zone linked to a non-compliant boundary. In the case of the B6 boundary this would incorporate generation zones 1 to 8. This targeted constraint charge is calculated based on the User's Meter Adjusted Volume as a proportion of total constraint volume multiplied by the cost of constraints arising from non-compliance with the GBSQSS; and

2. A Residual BSUoS Charge (BSUoSTOTR) that is calculated based on the User's proportion of the Total BMU Metered Volume (QM) (MWh) for each settlement period multiplied by the Residual BSUoS tariff this being derived from the Total BSUoS Charge less the cost of constraints arising from non-compliance with the GBSQSS.

.

The revised total BSUoS Charge will be calculated in the following way:

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

The TCC per User is calculated based on the User's proportion of BM Unit Metered Adjusted Volume for each Settlement Period relative to the Total Meter Adjusted Volume for Constraints due to non compliance for each Settlement Period.

For all other BMUs the value for TCC included in the overall BSUoS Charge will be zero.

For those affected BM Units, the TCC is calculated as, for each non-compliant derogated boundary as:

$$TCC_{ij} = \frac{TOTCC_j}{\sum QMadj_j} * QMadj_{ij}$$

Where:

TCC_j	Targeted Constraint Charge applicable to BM Units for Settlement Period j
$TOTCC_j$	Total Constraint Costs due to non compliant derogated boundary for settlement period j
$QMadj_{ij}$	BM Unit Meter Adjusted Volume
$\Sigma QMadj_j$	Sum of all BM Unit Meter Adjusted Volumes

The TCC is therefore derived by determining a £/MWh for the Constraint Charge by dividing the Total Constraint Costs due to non compliance by the total BM Unit Meter Adjusted Volumes and multiplying by a specific BM Unit Meter Adjusted Volume.

What is Metered Adjusted MW ($QMadj_{ij}$)?

Managing export constraints is likely to involve reducing the output of plant that sit behind that boundary. The charge of accomplishing this reduction in output (and subsequent energy replacement activity) is then allocated on parties based purely on their MW position. Those parties that have had bids taken on them will be exposed to a lower value of costs as their metered position will have been effected.

Therefore BMU will be charged on their intended output position prior to any actions to resolve the constraint undertaken by the SO. This Meter Adjusted volume is the sum of the BMU energy position and the net volume of any actions taken by the SO to resolve the constraint.

The types of actions taken that would be assigned back to the BMU would be:

1. Bid Offer acceptances as defined in the BSC;
    a. QAOij – Accepted Offer Volume
    b. QABij – Accepted bid Volume

2. Locational trades as undertaken under schedule 7 of the GTMA agreement; (GTMA sch7)

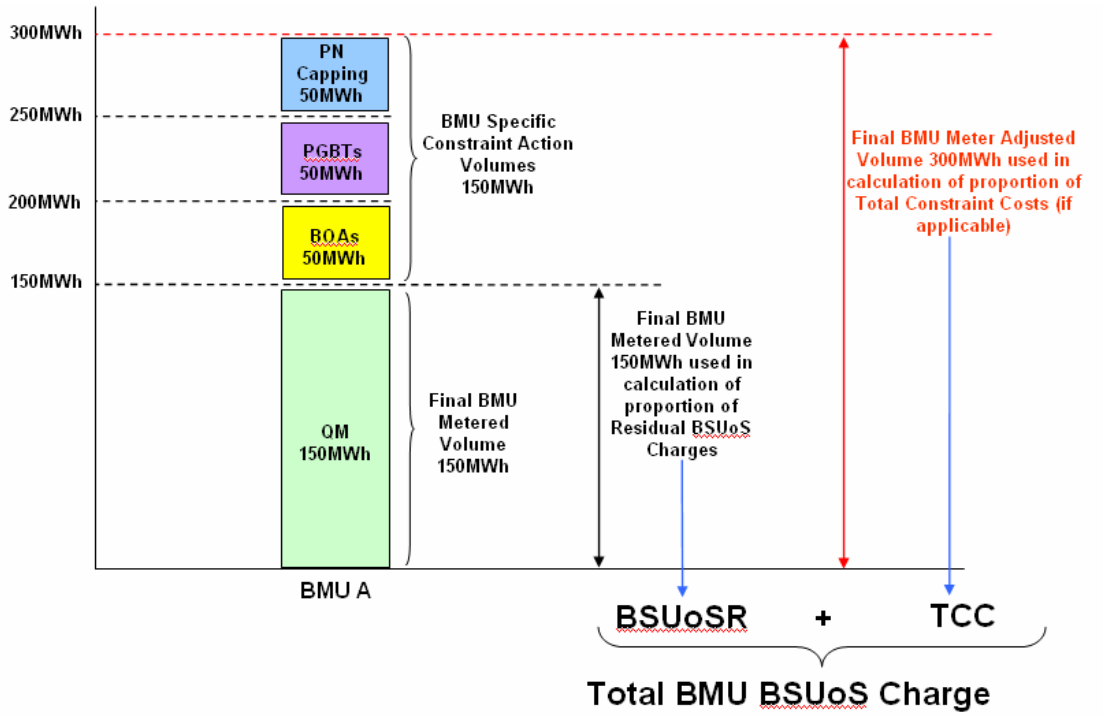
3. Pre Gate Balancing Transactions (PGBT); and

4. PN capping contracts (PN Cap).

    The SO may enter into an agreement with a generation station whereby the Maximum level of the summated FPN position across the station is capped for an agreed number of settlement periods in a day. This limits the MW load that can flow across the boundary in question. The value of this contract is measured in relation of the volume of MW restricted from the system that would otherwise have generated load onto the network

Therefore the final adjusted MW position ($QMij_{adst}$) would equal

$$(QMadjij) = QMij + QABij - QAOij - (GTMA\ sch7)_{buy} + (GTMA\ sch7)_{sell} - (PGBT\ sch7)_{buy} + (PGBT)_{sell} + (PN\ Cap).$$



How do we bill/Invoice these charges?

Stage	Timing	Current Methodology	Proposed	
		BSUoSTOT	BSUoSR	TCC
II	Settlement Day + 5 Working Days	BSUoSTOT based on II data	BSUoSR based on II Data	No TCC to be included
SF	Settlement Day + 16 Working Days	BSUoSTOT based on SF data	BSUoSR based on SF data	TCC based on II data
SF*	Settlement Day + 30	N/A	No change to BSUoSR	Reconciliation of TCC based on SF Data
RF	Settlement Day + 14 Months	BSUoSTOT based on RF Data	BSUoSR based on RF data	TCC based on RF data
EoS	In June of following financial year.	Reconciliation for Eos based on RF, R1, R2 or R3 data.	Reconciliation for Eos based on RF, R1, R2 or R3 data.	Reconciliation for Eos based on RF, R1, R2 or R3 data.

Invoicing

Invoicing BSUoSR and TCC will be in line with the current settlement calendar as above. Where previously Users received an invoice for total BSUoS they will now receive invoices for BSUoSR and TCC.

Volumes used in calculating TCC at the SF stage will be based on II data. Reconciliation of TCC could either take place at EoS along with reconciliation of BSUoSR or take place outside the settlement calendar or be done approximately 30 working days post settlement day.

Appendix 4: Proposed modification to the TNUoS Charging Methodology

Under this proposal the wider zonal generation tariffs will be recalculated. The locational element for generators within a geographical zone linked to a Non-Compliant boundary will be scaled to be consistent with a compliant system boundary. This will be done by applying a Capacity Scaling Factor to the nodal TEC values of all generators located within a geographical zone linked to a non compliant boundary.

The calculation of the nodal marginal MWkm for generation that is not within a geographical zone linked to a non-nompliant boundary is unchanged. This is shown in the following diagrams for the example of the Cheviot or B6 boundary.

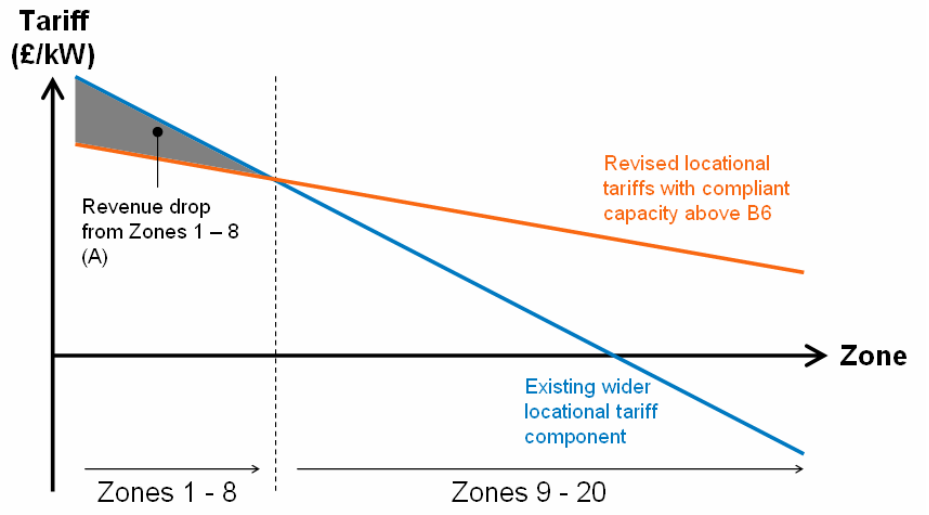


Figure 1 shows the effect on the locational component of the tariff (orange) when scaling generation above the B6 boundary compared with the existing 2009/10 wider zonal tariff locational component (blue)

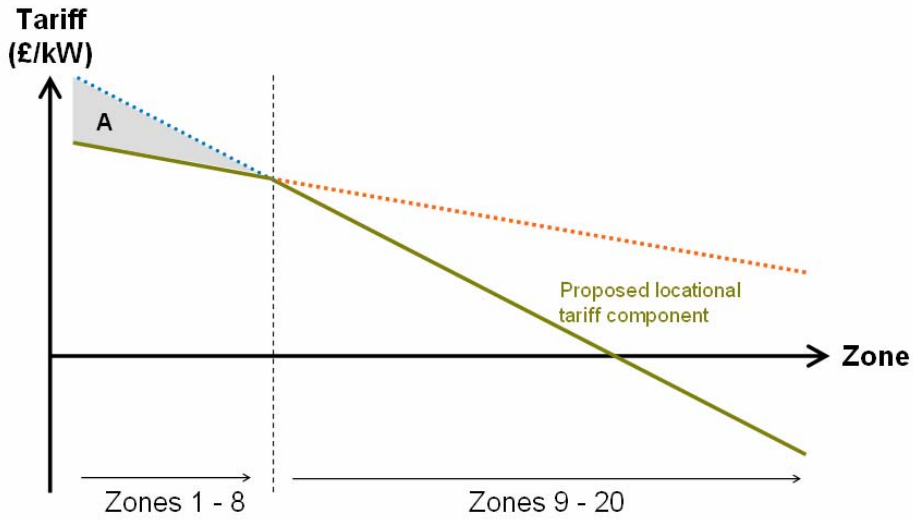


Figure 2 shows the proposed locational component of the tariff before the residual component of the tariff is added

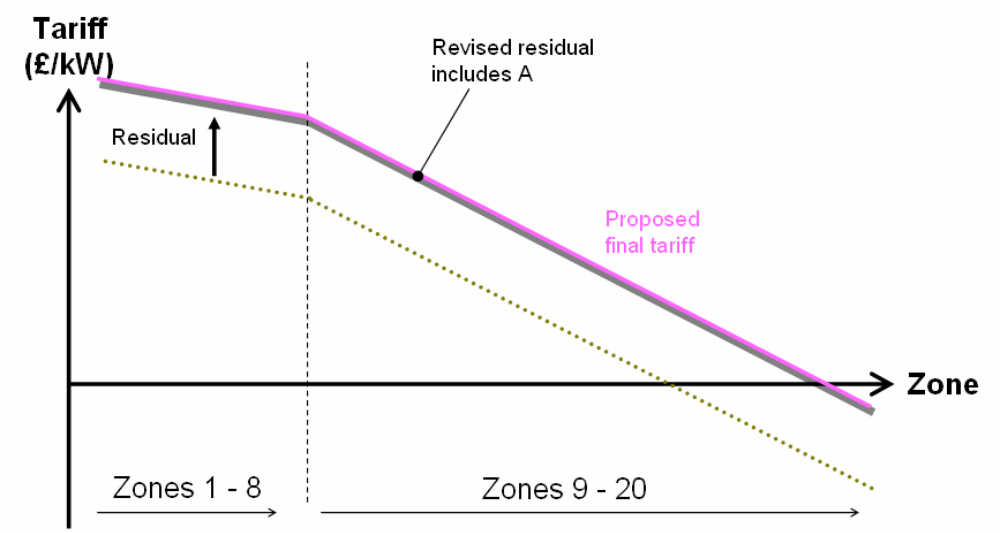


Figure 3 shows the final tariffs when the residual component is included

At present, the only system boundary where a Capacity Scaling Factor will be applied is the B6 boundary, which corresponds to the boundary between SPTL's and NGET's transmission areas. Consequently, the revised calculation of nodal marginal MWkm will be applied to all generator nodes in generation zones 1 to 8.

The Capacity Scaling Factor will be the reduction in generation capacity in generation zones 1 to 8 required to bring that boundary back to compliance with the Planning Standards. The Capacity Scaling Factor for 2009/10 will be 78.6%.

The methodology for the calculation of the final tariffs from the locational component will be unchanged, albeit with the nodal marginal MWkm for generation coming from two separate calculations (i.e. one calculation for nodes for generators within a geographical zone linked to a non-compliant boundary and another for generators not within a geographical zone linked to a non-compliant boundary).

The chargeable capacity for a generator will remain unmodified. This includes the method for determining the chargeable capacity for a generator in a negative zone, in addition:

- The local components of a generators annual liability will remain unaltered.
- Generation reconciliation will be unchanged; and
- The demand TNUoS charging methodology will not be modified.

The new wider zonal generation tariff will be applicable from the 1st of the month following the Authority's decision.

The change would be implemented mid year resulting in two sets of wider zonal tariffs applicable for a charging year. The annual liability for a generator would be calculated by pro rating the two tariffs across the year. Please see example in figure 4.

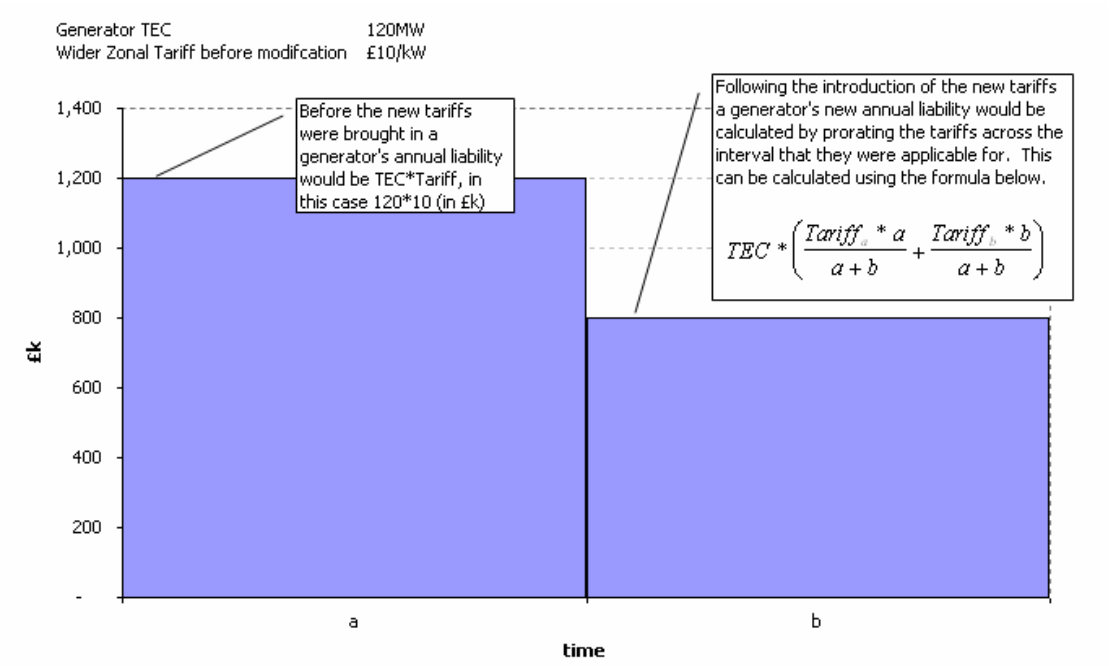


Figure 4 Change in example generator wider zonal annual liability due to introduction of new wider zonal tariff mid year

The calculation of a generators monthly TNUoS wider zonal liability will remain unchanged from the existing methodology (see examples below). It is not the intention of the modification for a generator who does not change TEC mid year to incur an interest liability due to the profile of their monthly TNUoS payments. However generators who increase their TEC mid year will incur an interest liability as normal. Their monthly TNUoS payments will be compared against what they would have been if the TEC increase had occurred at the start of the year and a resultant interest liability calculated.

Month	Wider Zonal Tariff £/MW	TEC	Annual Liability BEFORE modification	Annual Liability AFTER modification	Monthly Liability £k
Apr	10	120	1200	-	100
May	10	120	1200	-	100
Jun	10	120	1200	-	100
Jul	10	120	1200	-	100
Aug	5	120	-	800	50
Sep	5	120	-	800	50
Oct	5	120	-	800	50
Nov	5	120	-	800	50
Dec	5	120	-	800	50
Jan	5	120	-	800	50
Feb	5	120	-	800	50
Mar	5	120	-	800	50
					800

Figure 5 Example generator monthly liability due to mid year change in tariffs where a generators TEC does not change through the year

Month	Wider Zonal Tariff £/MW	TEC	Annual Liability BEFORE modification	Annual Liability AFTER modification	Monthly Liability £k
Apr	10	0	-	-	0
May	10	0	-	-	0
Jun	10	0	-	-	0
Jul	10	0	-	-	0
Aug	5	0	-	-	0
Sep	5	0	-	-	0
Oct	5	0	-	-	0
Nov	5	120	-	800	160
Dec	5	120	-	800	160
Jan	5	120	-	800	160
Feb	5	120	-	800	160
Mar	5	120	-	800	160
					800

Figure 6 Example generator monthly liability if the generator commissions within the year

Generation		Current 2009/10 Tariffs	2009/10 Tariffs AFTER the modification	Difference	
Zone No.	Zone Name	Wider Zonal Tariff (£/kW)	Wider Zonal Tariff (£/kW)		%
1	North Scotland	21.588654	18.455832	-3.13	-15%
2	Peterhead	20.318087	17.475407	-2.84	-14%
3	Western Highland & Skye	21.104228	19.526208	-1.58	-7%
4	Central Highlands	16.871037	14.663030	-2.21	-13%
5	Argyll	13.993686	11.763158	-2.23	-16%
6	Stirlingshire	14.479695	12.055384	-2.42	-17%
7	South Scotland	13.601728	11.753645	-1.85	-14%
8	Auchencrosh	11.243738	8.998144	-2.25	-20%
9	Humber & Lancashire	6.142320	6.461391	0.32	5%
10	North East England	9.853652	10.172723	0.32	3%
11	Anglesey	6.872452	7.191523	0.32	5%
12	Dinorwig	6.189823	6.508894	0.32	5%
13	South Yorks & North Wales	4.197861	4.516932	0.32	8%
14	Midlands	2.110543	2.429614	0.32	15%
15	South Wales & Gloucester	-1.603175	-1.284104	0.32	-20%
16	Central London	-6.977964	-6.658893	0.32	-5%
17	South East	0.254498	0.573569	0.32	125%
18	Oxon & South Coast	-1.386678	-1.067608	0.32	-23%
19	Wessex	-3.282014	-2.962943	0.32	-10%
20	Peninsula	-6.683832	-6.364761	0.32	-5%
	Small Generator Discount	5.184279	5.264047	0.08	2%

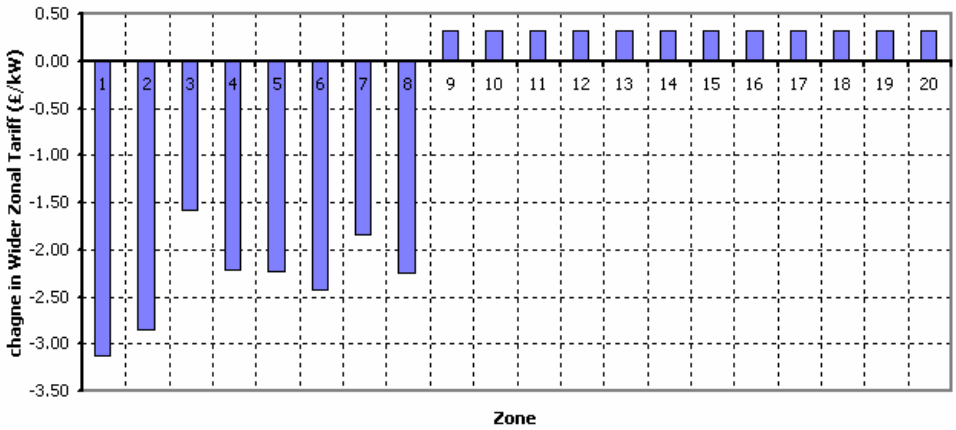


Figure 7 Forecast new wider zonal tariffs compared against existing 2009/10 tariffs