nationalgrid

CONSULTATION DOCUMENT

GB ECM-13

For the treatment of the residual generation tariff in The calculation of Transmission Network Use of System (TNUoS) Tariffs

March 2009

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1 Executive summary

In October 2008, National Grid published a pre-consultation document which presented three proposals for industry comment, to modify the way in which the residual element of the Transmission Network Use of System (TNUoS) generation tariff is calculated and levied, in light of the CUSC Amendment Proposals (CAP161-166). These options can be summarised as follows:

1. **Commoditisation:** whereby the residual element of the TNUoS generation tariff is levied as a uniform charge on generation Users of the transmission system on a half-hourly metered generation basis (£/MWh) for every settlement period throughout the charging year.
2. **Local Capacity Nomination:** whereby the residual element of the TNUoS generation tariff is levied on a capacity basis on generation Users of the transmission system based on their 'Local Capacity Nomination' (£/MW).
3. **Daily Peak Generation:** whereby the residual element of the TNUoS generation tariff is calculated as a daily peak utilisation charge based on the metered generation over the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) every day over the charging year (£/MWh).

The pre-consultation document has been published on the National Grid charging website in addition to the industry responses received, at the following address:

http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

This consultation document summarises the views of the industry expressed in the ten responses received to the pre-consultation document and gives further consideration to the three options, which National Grid considers potentially better meet the relevant objectives with regard to transmission charging.

For the avoidance of doubt, this consultation does not propose any changes to demand tariffs, and it is the intention that the locational element of the TNUoS tariffs for both generation and demand will continue to be levied on a capacity basis to provide efficient investment signals for generation projects to locate in areas of the transmission system which will minimise the level of investment required.

Comments and views are invited on all of the issues raised in this consultation document. To ensure that your comments and views are considered, responses should be emailed to craig.maloney@uk.ngrid.com by close of business on **Tuesday 31st March, 2009**.

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;

(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 further set out the options available for National Grid's proposal to modify the Statement of the Use of System Charging Methodology in the calculation of the residual element of the TNUoS generation tariff with a view to better meeting the relevant Transmission Licence objectives set out above, and invite industry views on the options presented.

3 Background

3.1 Transmission Access Review (TAR)

National Grid presented a suite of CUSC Amendment Proposals to the CUSC Amendments Panel in April, 2008. Subsequently, the Panel recommended that three Working Groups were established to further consider the Amendment Proposals, which can be viewed on the National Grid website:

http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

In summary:

- **CAP161: System Operator Release of Short-term Entry Rights** proposed that National Grid as GBSO, be permitted to release additional entry rights to generators in operational timescales through an auction process when it believes that there is economic, spare capacity available on the GB transmission system;
- **CAP162: Entry Overrun** proposed to create a commercial mechanism for dealing with a generator's export over and above its total transmission access holding;
- **CAP163: Entry Capacity Sharing** proposed to introduce a zonal access product, allowing generators to connect to the GB transmission system without wider system access rights and facilitate intra-zonal access sharing between generators on a 1:1 basis;
- **CAP164: Connect and Manage** proposed that generators who wish to connect to the transmission system should have a fixed date for receiving TEC. The 'TEC effective date' being the latter of the completion of "local" transmission works or an agreed fixed lead time;
- **CAP165: Finite Long-term Entry Rights** proposed the introduction of temporally defined finite long-term entry access rights and associated User commitment. Existing generators would nominate the number of years for which they require long-term entry access rights to the GB transmission system and underpin this with User commitment in the form of a liability to pay associated charges and a requirement for financial security to be put in place. New generators (and any existing generators requesting an increased level of long-term entry access) would be required to book a defined number of years of entry access rights and provide the associated User commitment; and
- **CAP166: Long-term Entry Capacity Auctions** proposed that all long-term entry access rights to the GB transmission system would be allocated by auction on a zonal basis, released in annual blocks.

Working Group 1 was established with the responsibility for assisting the CUSC Amendments Panel in the evaluation of CUSC Amendment Proposals CAP161, 162, 163 and 164 to consider whether each of them individually better facilitate achievement of the applicable CUSC objectives.

Working Group 2 was established with the responsibility for assisting the CUSC Amendments Panel in the evaluation of CUSC Amendment Proposals CAP165 and 166, and considering whether each of them better facilitates achievement of the applicable CUSC objectives.

Working Group 3 was established as a sub-group responsible for assisting Working Groups 1 and 2 in evaluating the enabling elements of CAP161-166 against the applicable CUSC objectives. Primarily, those enabling elements were considered to be:

1. The consideration of treatment of the non-locationally varying residual element of the TNUoS generation tariff given the potential use of the transmission system by Users that do not obtain long-term access rights.
2. The consideration of appropriate generation zones which facilitate the ability to obtain capacity on both a short and long-term basis.
3. The consideration of new local charging arrangements.

Final Amendment Reports for CAP161-165 were submitted to the Authority for consideration in January, 2009.[1] CAP166 has recently been out for industry consultation, with a deadline for responses of 23rd February, 2009.[2]

This GB ECM-13 consultation document follows a pre-consultation document published in October 2008[3] and presents for further industry comment, three options for the treatment of the residual element of the TNUoS generation tariff.

3.2 TNUoS charging principles

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

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 TOs price control review for the succeeding price control period. TNUoS charges are set to recover the MAR, 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.

The basis of charging to recover allowed 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)".[4]

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 TO's costs, if they were to increase or decrease their use of the respective systems.

The TNUoS tariff comprises two separate elements. Firstly, a locationally varying element derived from the Direct Current Load Flow (DCLF) ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. In 2008/9, locational generation tariffs range from between £18.15/kW

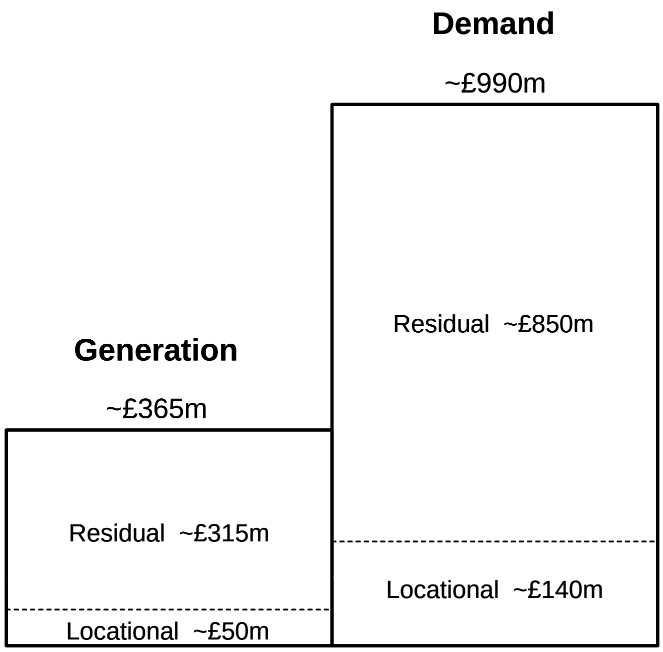
[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/
[2] http://www.nationalgrid.com/NR/rdonlyres/5D7CB3A0-078D-429E-A3D3-E0CA4CD24511/31858/CAP166CompanyConsultationv10Issued.pdf
[3] http://www.nationalgrid.com/NR/rdonlyres/D26D9CDA-6D83-4E11-894F-AAB7C9F6925F/29079/GBECM13DraftvFINAL12.pdf
[4] http://www.nationalgrid.com/NR/rdonlyres/58084876-C547-4099-A5EC-4E8E6A09D825/26767/Scanjob_20080528_105159.zip

(Northern Scotland) and -£12.63/kW (Peninsula), whilst locational demand tariffs range from between £9.75/kW (South Western) and -£12.55/kW (Northern Scotland).

Secondly, a non-locationally varying element 'the residual element' relating to the historic 'lumpy' investment in both locational and non-locational assets (i.e. substation assets) in addition to the provision of residual revenue recovery. In 2008/9, the residual tariff is £4.11/kW for generation and £15.40/kW for demand. The combination of the locational and residual elements forms the total TNUoS tariff.

A breakdown of how National Grid forecasts to recover the appropriate proportions of it's MAR through TNUoS charges for 2008/9 (of ~£1.35bn), is provided in Figure 1.

Figure 1 2008/9 TNUoS revenue recovery



Following the Authority's decision on 15 December 2008[5] not to veto *GB ECM-11 "charging arrangements for generator local assets"* TNUoS generation charges for all generators will be split into four components from 1 April 2009. These can be summarised as follows:

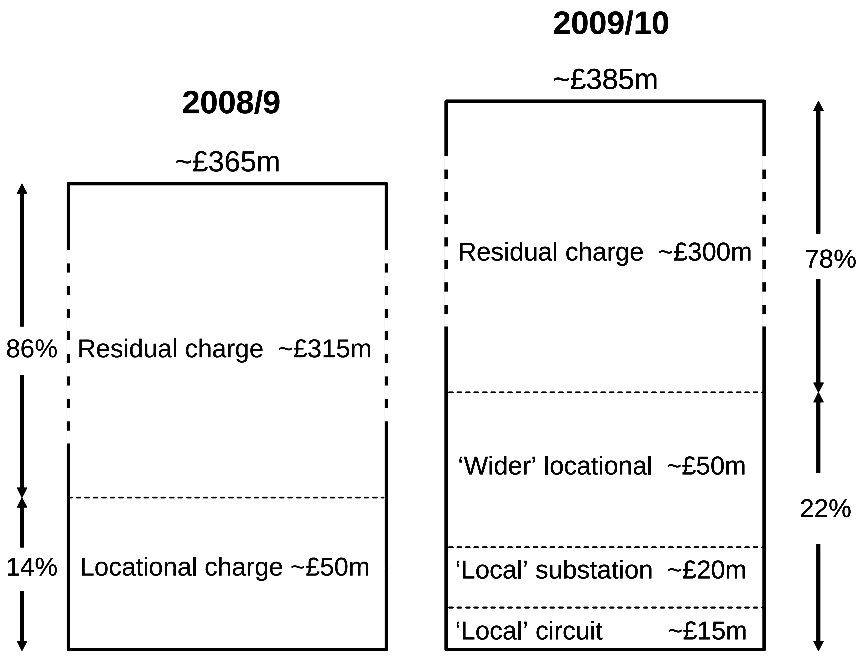
- ***'Local' circuit charge.*** This charge is derived with reference to the incremental power flows along "local" transmission infrastructure circuit assets between the generation node and the next Main Interconnected Transmission System (MITS) substation, together with updated generic unit costs for the relevant design type of circuit for each generation connection. A local security factor of 1.0 is applied to single circuit connections, whereas for all other instances the local security factor is the existing GB average security factor, currently 1.8.
- ***'Local' substation charge.*** This element of the TNUoS charge is derived from the updated average generic cost analysis of the relevant design and type of local infrastructure substation assets which are required for each generation connection.

[5] http://www.nationalgrid.com/NR/rdonlyres/E687A926-D24F-4121-9CF3-EAD879AF91A6/31067/GBECM11decisionletter.pdf

- ***'Wider' locational charge.*** Calculated consistent with the existing TNUoS charging methodology, based on the existing zonal averaging approaches and the generic cost base of the current charging model. To avoid double counting, the incremental costs along the local circuits are subtracted from the wider zonal generation cost weighted average on which the wider zonal tariff is based.
- **Residual charge.** Serving the same purpose as the current residual charge.

Figure 2 identifies the forecast revenue from each of the four generation charging components for the 2009/10 charging year and compares these to the revenue forecast to be recovered from the locational and residual TNUoS tariffs in 2008/9.

Figure 2 2009/10 Forecast TNUoS revenue recovery from generation



Whilst the residual tariff for both generation and demand varies year on year dependent on factors such as changes to the transmission network, the locations of generation, demand and their associated charging bases, the locational element of the TNUoS tariff (for both generation and demand) has historically been responsible for recovering in the region of 15-25 percent of the MAR from TNUoS tariffs. This is the result of the netting off of locational revenues derived from generation and demand Users, which can be both positive and negative dependent upon their location.

Since the implementation of TNUoS tariffs derived from the ICRP model in 1993/4, the residual element of the tariff has recovered in the region of 75-85 percent of National Grid's allowed revenue from TNUoS. Prior to 2002, an element of TNUoS revenue was recovered from what was termed a 'security element'. This element of the tariff was effectively used to recover the same historic lumpy investment in both locational (i.e. towers, cables and overhead lines) and non-locational (i.e. substation) assets for which the current residual tariff is used.

With the implementation of GB ECM-11 effective from 1 April 2009, the forecast split in revenue in 2009/10 for generation specifically, is 22 percent from 'locational' tariffs and 78 percent from the residual element.

3.3 Interaction with the Transmission Access Review

Under the current TNUoS charging arrangements, both the locational and residual elements of generation charges are calculated and levied based on the TEC of a generator. Given the potential introduction of a range of short-term access products proposed by CAP161-164, it may no longer be considered appropriate to charge the residual element of TNUoS tariffs on TEC, as it is foreseeable that Users will be in a position to obtain access to the transmission system on a short-term basis with no requirement for TEC. In this instance, Users would benefit from the historic lumpy investment in both locational and non-locational transmission assets which might ultimately be responsible for the availability of this access, without contributing towards some of the costs of providing that access.

3.4 European tarification guidelines

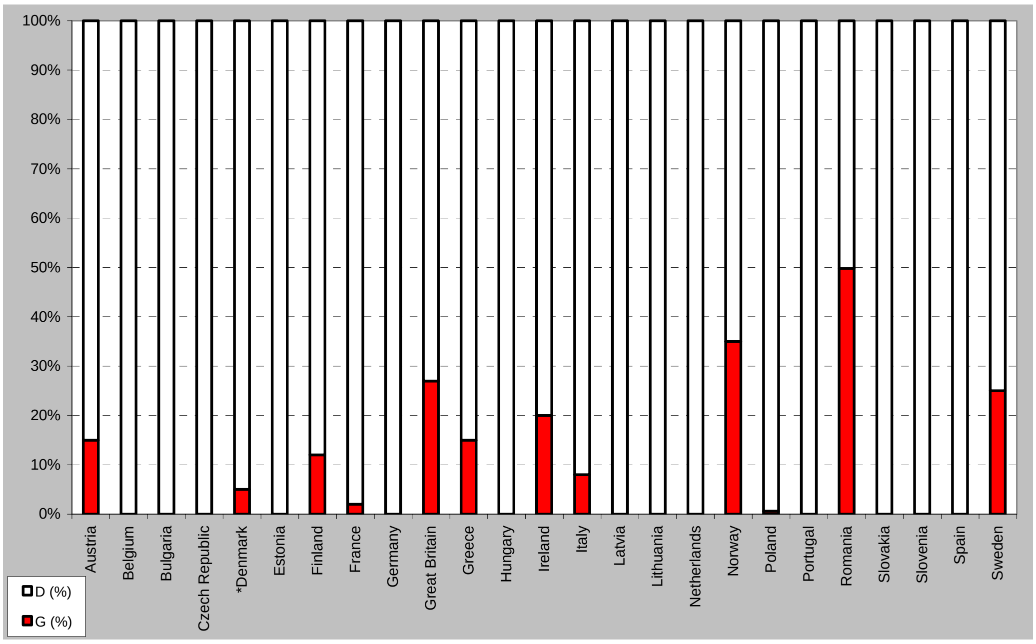
In addition to the relevant licence obligations outlined in Section 2 of this document, it is also worth giving cognisance to European tarification guidelines.[6] The current guidelines state that the ‘annual national average G’ for Great Britain should not exceed €2.5/MWh.

‘Annual national average G’ is the annual total transmission tariff paid by all generators divided by the total energy injected annually. On the assumption that ~£385m is recovered from generation Users in 2009/10, with an ‘energy injection’ of ~327TWh, the ‘average G’ charge from TNUoS equates to ~£1.18/MWh. Given current exchange rates in the order of 1.10 Euro / £[7], the ‘Annual national average G’ for Great Britain, maintaining the existing 27/73 percent G/D split is comfortably within these guidelines at ~€1.30/MWh.

In 2007, the average G/D split in revenue recovery throughout Europe was approximately 8.6% from generation and 91.4% from demand. Figure 3 identifies the G/D split for each of the European countries represented in the study, with the proportion of revenue recovered from generation highlighted in red.

[6] http://www.nationalgrid.com/NR/rdonlyres/CA7F2638-AF19-4BD5-A7E6-7143C274E120/25946/ETSOTariffsGuidelines.pdf
[7] Source: Bank of England, December 2008

Figure 3 G/D split by European country, 2007



(ETSO Overview of transmission tariffs in Europe: Synthesis 2007, June 2008[8])
* Figure for Denmark ranges between 2-5% generation and 95-98% demand

3.5 Interaction with recovery of Maximum Allowed Revenue

The role of the residual generation tariff in the event of an over-recovery of generation revenue from the allocation of long-term access products was discussed by the TAR Working Group 3 prior to the publication of the GB ECM-13 pre-consultation. Whilst this is a valid concern which may require further consideration by the industry at some point, it is not intended that the treatment of over-recovery of revenue from generation will be addressed as part of the GB ECM-13 consultation process. Instead, this will be considered as part of an independent consultation in the future, in the event that over-recovery becomes a possibility through the implementation of any of the Amendment Proposals, particularly CAP166: Long-term Entry Capacity Auctions.

[8] http://www.etso-net.org/upload/documents/11.a.%20Final_Synthesis_2007_18-06-08.pdf

4 Industry responses to pre-consultation

Ten industry responses were received to the GB ECM-13 pre-consultation document. This section presents those views expressed in response to the issues raised in the pre-consultation.

4.1 Liability for short-term Users

Eight respondents believed that it is appropriate that all generators with access rights, whether obtained via short-term or long-term access products should contribute to the recovery of residual revenue from TNUoS generation charges.

Many respondents supported the development of charging arrangements that allow the costs of using the transmission system to reflect appropriately onto parties that cause them. The creation of a specific non-locational charge which is separate from the locational element of the TNUoS generation tariff was supported, which may be recovered on a different basis to the current TEC-based charge.

Mindful that the residual element is related to the “lumpy” nature of the investment that TOs undertake, a respondent believed that it is important that all generators connected to the system are liable to pay a proportion of the residual TNUoS charges, meaning that the charge should be levied on generators with both ‘firm’ and ‘interruptible’ access rights. The existing TEC arrangements were perceived to be inappropriate due to the need to charge generators who may be using the system on the back of interruptible rights.

A respondent noted that the treatment of the residual element of the TNUoS tariff is an essential element of many of the CUSC Amendment Proposals 161-166, in which its role should be to ensure that generators do not free ride on elements that they would have been subject to under the existing TNUoS regime, if they use alternative shorter term products developed, such as SO Release or Overrun.

A respondent noted that even when an existing User only holds local capacity, the User is still potentially blocking a new entrant from holding capacity at that location on the transmission system, who may have a better economic model that enables them to make better use of wider access products. The respondent therefore considered that all Users should have to pay the residual element of the TNUoS tariff, in order to incentivise those Users that do not use their local capacity to relinquish their rights, in order to allow those Users that could use the local connection more efficiently to connect.

No respondents believed that it was inappropriate for all generation Users to contribute to the recovery of residual revenue from TNUoS charges, although two respondents considered that Users of short-term access products should be liable for an element of the residual TNUoS generation tariff only. A respondent considered that it is not cost-reflective or equitable for Users of short-term access to pay the full amount of the residual tariff in addition to the short-term charge for access. The respondent did not accept that none of the residual element is related to the provision of system-wide access, which in the case of Users of short-term access products is being paid for separately.

4.2 TNUoS revenue split

Two respondents believed that the existing 27/73 percent revenue split between generation and demand remains appropriate, on the grounds that the TAR Working Groups have all proceeded on this basis and that there does not appear to be any argument as to why the split in liability should be altered.

A respondent did not consider that the GB ECM-13 consultation process is an appropriate forum for discussing the 27/73 percent revenue split, but noted support for moving towards “absolute G equal to zero” to achieve convergence with generation charging in the European Union.

A respondent did not feel that it is essential to review the existing G/D revenue split as part of the GB ECM-13 consultation process and considered that it would certainly not be sensible for the split levied on generation to move further away from the European average.

A respondent considered that if stronger justification for moving away from the current charging principles can be demonstrated, and a commoditisation approach is to be seriously considered, it would be appropriate to consider this alongside a change to the G/D revenue split. The respondent added that it may be appropriate to move to a G=0 approach at the same time as implementing a commoditised residual TNUoS methodology to ensure that a truly fair commoditisation scheme would exist, by removing the adverse effects of transmission charging from the economics of the wholesale generation market and basing it upon demand.

A respondent considered that mindful of transmission tarification guidelines published by the European Regulators Group for Electricity and Gas (ERGEG) which advocate the harmonisation of use of system charges for generators across Europe, it would be appropriate to support a gradual reduction in the wider shared asset charge levied on generation Users in GB towards zero.

4.3 Options

4.3.1 Local Capacity Nomination

Supportive

Five respondents supported the implementation of a methodology by which the residual element of the TNUoS generation charge is levied on the basis of a Local Capacity Nomination.

Two respondents noted that the transmission system is designed on a capacity basis as specified in the GB SQSS and therefore charges should be levied based on the capacity of a generator. A respondent considered that the transmission system is designed on a capacity basis as specified in the GB SQSS and therefore charges should be levied based on generator capacity. The respondent considered that whilst some assumptions of a typical operating regime may be made in designing generation connections, two generating plants of the same capacity and fuel type will be treated in the same manner by National Grid. The respondent believed that there will not be any significant difference between the infrastructure built for a plant operating at 40% load factor or one operating at 80% load factor. The respondent considered that capacity charging ensures that the basis for charging is transparent and non-discriminatory and until such time that transmission system design is made on the basis of something other than generator capacity, anything other than a capacity based charge is inappropriate.

A respondent considered that the residual TNUoS generation tariff should be based on LCN due to the fact that all generators would hold capacity, regardless of whether they have procured (a) local capacity with an option to use short-term wider capacity, or (b) a mixture of local and long-term wider capacity. The respondent considered that if an Overrun product is introduced, all Users with LCN would effectively be guaranteed access to the wider network and noted that Users should only hold such a right if they intend to use it, with holders of LCN incentivised not to block new entrants by holding onto an access right that they do not use.

A respondent supported charging for TNUoS on the basis of LCN as it is inefficient for fixed costs to be charged on a marginal basis. The respondent considered that the structure of charges should reflect how costs are incurred, so fixed investment costs and marginal operating costs should be charged as fixed and variable costs, respectively. The new variable cost from generating any extra power would naturally and inevitably be included in the marginal cost of generation and would affect pricing in the Balancing Mechanism and thus imbalance cashout pricing as well as the forward market, which is in symbiosis with cashout pricing and with Balancing Mechanism Bid / Offer pricing.

A respondent considered that whilst there is legitimate concern that those Users opting for shorter-term products would be exposed to this cost even if they were unsuccessful in acquiring wider access, this option represents the minimum change to the basis of charges used at present and is the least controversial to implement. On balance, the respondent considered that LCN would seem the most appropriate option as it represents least change and if issues with this approach are encountered in due course, the basis of allocation can be reassessed at this time.

A respondent considered that the basis of LCN appears the most stable and transparent means of charging and whilst not entirely cost reflective, it would be easier for generators to forecast and manage risk.

Unsupportive

Five respondents did not support the implementation of a methodology by which the residual element of the TNUoS generation charge is levied on the basis of a Local Capacity Nomination.

Two respondents did not believe that the local capacity reflects the actual wider usage of the non-locational elements of the transmission system and therefore a charge based on this could not be considered as cost reflective. A respondent expressed concern that the nature of local capacity has not been fully developed and evaluated as part of the TAR process.

A respondent considered it inappropriate to charge potential Users of short-term access products on the basis of LCN because although these Users have expressed an interest in using short-term products, it may be that the charging methodologies introduced for products such as Overrun and SO release will make these products uneconomic to Users. Such a charge could therefore result in a User paying an element of the residual charge having failed to secure any transmission access at all.

4.3.2 Commoditisation

Supportive

Four respondents supported the implementation of a methodology by which the residual element of the TNUoS generation charge is levied on the basis of utilisation of the transmission system throughout the charging year.

A further respondent supported the principle of charging generation Users for use of the GB transmission system on the basis of utilisation rather than capacity, but noted that this approach could not be supported without an equal and corresponding change to the locational tariff in the belief that there should be a wider shared transmission charge (recovering the sum of the current locational and residual elements) that is levied as a uniform tariff across GB.

Two respondents believed that the recovery of the residual generation tariff based on utilisation over an entire charging year best reflects a generators' use of the transmission system. A respondent noted that such an approach would correct the anomaly between the SQSS (where an allowance is made for the lower load factors in determining the level of infrastructure investment required for intermittent generation) and the DCLF ICRP model which makes no allowance for low load factor plant.

A respondent considered that levying the residual generation tariff based on actual utilisation of the transmission system is a useful development in the residual element of the TNUoS methodology. The respondent noted that in the coming years, increasing levels of low load factor plant will connect to the transmission system and parts of the current thermal fleet will significantly change their running regimes in response to environmental legislation. In addition, the respondent considered that there is likely to be an increase in the effective sharing of capacity. Given these factors, the respondent considered a charge based on utilisation to be the most appropriate way in which to levy the residual element as this can be considered more cost reflective whilst reducing the barriers to entry for low load factor plant and thereby facilitate competition.

A respondent considered that having been through a long period of relative stability in generating conditions, the GB electricity generation market is now going through a period of unprecedented change which is manifest regardless of plant age and condition, technology, fuel or location. The respondent noted that carbon-based generators are now subject to stringent environmental and emissions controls, whilst renewable technologies are encouraged and incentivised as a result of national and European policies and, increasingly, legislation.

With the future for nuclear generation in GB remaining uncertain given, in particular, obstacles in the planning process and more generally, the volatility of commodity and fuel prices, the respondent noted that supply businesses are now seeking change in response to the demands of their customers. These, and other, factors have contributed (and continue to contribute) to significant changes in the operation of generation Users and, hence, their use of the GB transmission system. Whilst agreeing that investment in generator only local assets is scaled to meet peak export capability (and, through a local asset tariff, should be charged on this basis), the respondent considered that it is becoming increasingly untrue that investment in the wider shared transmission system is – or, indeed, should be – on the basis of meeting generators' peak export capabilities, with this being recognised by the transmission businesses and being progressed through a fundamental review of the system planning standard. The respondent considered that it is certainly not the case that a megawatt of wider shared transmission capacity is built for each megawatt of generation that connects and that it is no longer appropriate or relevant to charge generation Users for use of the wider shared transmission network on the basis of capacity reservation. The respondent considered that generators will not all be able to respond to conditions of peak demand, and investment in the transmission system will no longer expect this. Hence, the respondent believed that the prevailing (and future) conditions are more suited to a charge for generators based on utilisation.

A respondent did not consider that a User that does not enjoy a general right of access to the transmission system should be liable for the full residual charge whilst also paying a charge of some sort for short-term access. The reasoning behind this view was that the residual element of the TNUoS tariff partially funds access to the wider system and parties should not have to pay this element of the residual tariff if they are also paying for this access through another product.

A respondent noted that the levying of the TNUoS generation tariff based on utilisation throughout a charging year appears a relatively simple approach to implement and spreads the cost of the residual charge according to load factor, so automatically copes with the anticipated larger number of low load factor generators that are expected to exist in the future. Another respondent considered that a charge based on utilisation would have the further advantage of stability and transparency and the reconciliation amount arising from changes in either the MAR or the total annual demand would be expected to be minimal.

Based on information in the public domain, a respondent estimated that around 60% of generation Users would experience a reduction in charges under a flat commoditised charging regime with no locational element of the TNUoS tariff, including all renewable generators. Of those generators that would experience an increase in charges, the respondent estimated that less than 10 Users would experience an increase of more than £5 million per annum (of which, the majority are currently liable for negative charges).

Unsupportive

Five respondents did not support the implementation of a methodology by which the residual element of the TNUoS generation charge is levied on the basis of utilisation of the transmission system throughout the charging year.

Two respondents considered that a charge based on utilisation is a significant change from the present principles of the residual TNUoS charging methodology, whilst a further respondent considered that a sufficient rationale or justification has not been made for moving away from the existing principles of levying TNUoS generation charges on a capacity basis. It was considered that the development of a charge based on utilisation is an unnecessary and fundamental change to transmission charging, which is secondary to the objective of the TAR.

A respondent considered that such a radical change in charging principles should be founded upon an in-depth investigation into the appropriateness of all aspects of transmission charging, whilst a further respondent wished for further work to be completed on the implications of adopting such an approach before a proposal is put to the Authority.

A respondent considered that the structure of charges should reflect how costs are incurred, so fixed investment costs and marginal operating costs should be charged as fixed and variable costs, respectively. It was noted that the new variable cost from generating any extra power, would naturally and inevitably be included in the marginal cost of generation and would affect pricing in the Balancing Mechanism and thus imbalance cashout pricing as well as the forward market, which is in symbiosis with cashout pricing and with bid/offer pricing.

A respondent considered that the commoditisation of the residual tariff would, rather perversely, reward the plant that uses its connection less efficiently and considered that it could be argued that the plant that uses its connection more would effectively cross-subsidise the connection of similar plant that uses its connection less. The respondent considered that the transmission charging regime should provide an incentive to those Users that make more efficient use of their connections, not reward those that hold capacity (of any type) and do not use it. A further respondent considered that a charge based on utilisation seems to undercharge generators who run at very low load factors, but who are located in areas where operation of the transmission system is most expensive.

A respondent considered that the implementation of a residual TNUoS generation charge based on utilisation could introduce perverse outcomes where a generator with TEC in a negative charging zone would receive a higher payment for access, the less they generate, whilst such a charge would also create instant winners and losers and cross-subsidies amongst industry parties.

A respondent considered that if the purpose of its introduction is simply to prevent certain generators from avoiding costs that they pay at present, then a utilisation approach would be inappropriate. The respondent also noted that by redistributing the burden of the residual charge on the basis of load factor, this will presumably change the basis on which these costs are reflected in energy prices as they will become fully avoidable costs.

A respondent considered that introducing a charge for recovery of the residual revenue based on utilisation will result in a combination of both £/kW and £/kWh charging for generators which will lead to unnecessary complexity and erode the existing stability and predictability of charging arrangements.

4.3.3 Daily Peak Generation

Supportive

No respondents specifically stated support for the implementation of a methodology by which the residual element of the TNUoS generation charge is levied on the basis of utilisation of the transmission system during times of daily peak generation over the period between 16:00 and 19:00 hrs inclusive (i.e. settlement periods 33 to 38) every day over the charging year. A respondent did consider however, that this approach brings many of the benefits of commoditisation whilst maintaining the link with recovering costs on a peak basis and for this reason the approach has merit and should go forward to the consultation phase.

A respondent considered that such an approach could provide appropriate incentives for those Users that make the most efficient use of the transmission system (i.e. no charge outside of peak times), whilst directing charges to those generators that create the congestion on the system during peak periods. The respondent considered that it is arguable that the transmission system is built in such a way to help cope with the demand at peak times during the day; which results in a proportion of the capacity only being used to provide peak capability. As the system is built to cope with these peak periods, the residual charge could be targeted at those that use the system during these peak times. The respondent considered that it seemed appropriate however, for National Grid to provide more in-depth analysis and a stronger rationale for the move away from the current charging principles prior to moving towards a commoditised approach (whether peak hour based or not).

A respondent considered that a utilisation charge based over daily peak periods has the benefit of overcoming the shortcomings of the LCN option and, whilst this approach could be seen as a disincentive against generating at times of peak demand, this is unlikely to be the case in reality. The respondent noted that instead, generators will recover these costs through the prices they offer in these periods, as the residual tariff will effectively be an avoidable cost at these times.

A respondent noted that the peak period during the winter months does not fit with that of the summer months and consideration should therefore be given to using a longer fixed duration to capture the times where the highest levels of generation occur. The respondent noted a preference for a modified version of the daily peak generation approach over a 12 hour period (0700-1900).

Unsupportive

Two respondents considered that this approach could potentially produce some perverse incentives for generation not to generate when the system needs generation.

A respondent did not support this approach on the basis that it may enable certain Users to avoid the residual charge and therefore payment for the wider non-locational elements of the system. The respondent considered that the charge might represent a cross-subsidy between those Users that are using the system in the relevant charging period and those that do not. However, all Users require the non-locational elements of the transmission system in order to use the system. Furthermore, although the system may be designed to meet peak demand, the respondent did not believe that this should be used to justify the recovery of the residual costs of the transmission system.

A respondent considered that for intermittent generation, such as wind, they are likely to be on average undercharged compared to the costs that they impose on the transmission system.

4.3.4 Calculation of monthly charge

Six respondents expressed support for any form of charge based on utilisation to be based on actual metered data rather than forecasts of a Users generation profile.

A respondent considered that calculating the charge on the basis of initial metering data seems the simplest way of determining an accurate charge, with the current BSUoS process offering a good framework. The respondent noted that the alternatives to basing the calculation on metering (either a User forecast or historic load factor) offer neither greater accuracy nor greater simplicity in determining the charge.

A respondent considered that monthly charges under either of the utilisation options should be calculated in arrears on the basis of actual metered generation on a basis similar to the BSUoS methodology with reconciliation taking place by 30th June following the end of each financial year. It was considered that the use of forecast data to produce estimated bills would be administratively complex and require further investment in systems for the submission and validation of forecast data.

A respondent noted that the requirement under the daily peak generation charge to forecast output for each day for the specified period would be subject to uncertainties for intermittent generators, whilst a further respondent considered that the settlement process will take too long and potentially be relatively costly for National Grid to administer. The respondent felt that charges will be difficult to forecast and be relatively volatile, depending on weather, use of generation for balancing etc.

4.4 Other comments

Rationale
A respondent considered that the proposals developed thus far have been on dubious grounds for change and urged National Grid to provide more in-depth analysis and a stronger rationale for the move away from the current charging principles.

Residual revenue recovery
A respondent noted that they have requested on many occasions, more detail as regards to the revenue that the residual tariff recovers. Whilst the pre-consultation explains that the 85% of National Grid's allowed revenue accounts for non-locational assets, 'lumpy' investment and historic system investment, National Grid has not yet provided any quantitative detail to this effect. The respondent considered that it is of paramount importance for the industry to understand what the residual revenue contains in order to understand how such a charge should be levied.

A respondent did not find it credible that the entire volume of the residual charge pays for "historical lumpy investment". For this reason, the respondent did not agree that parties that are paying for wider access through other mechanisms should be liable for the full residual charge, however it is levied. In order to establish how much of the residual charge that they should be paying for, the respondent considered that some analysis in more detail than has been made available previously of the difference between the allowed revenue and the amount covered by locational charges needs to be undertaken. In addition, the respondent considered that a rationale needs to be developed for the proportions of the cost of substations that are regarded as being to provide access to the system.

Volatility of tariffs
A respondent expressed concern regarding the risk of significant volatility in any commodity charge which may arise from the patterns of generation which can vary significantly year on year (as a result of variables like the weather) and the currently

unknown mechanism for over and under recovery. The respondent considered that the volatility of a commodity based charge could be significantly greater than the volatility of TNUoS capacity-based charging and requested further work in assessing the potential volatility and predictability of the charge and any associated over/under recovery mechanism.

Over / under recovery
A respondent considered that the residual tariff is only part of a package of charges and cannot therefore be considered on a standalone basis. The respondent noted that they would like to see the whole package of charges for transmission access before coming out in support of a particular proposal, notably the mechanism for over and under recovery funding needs to be known.

5 Further analysis

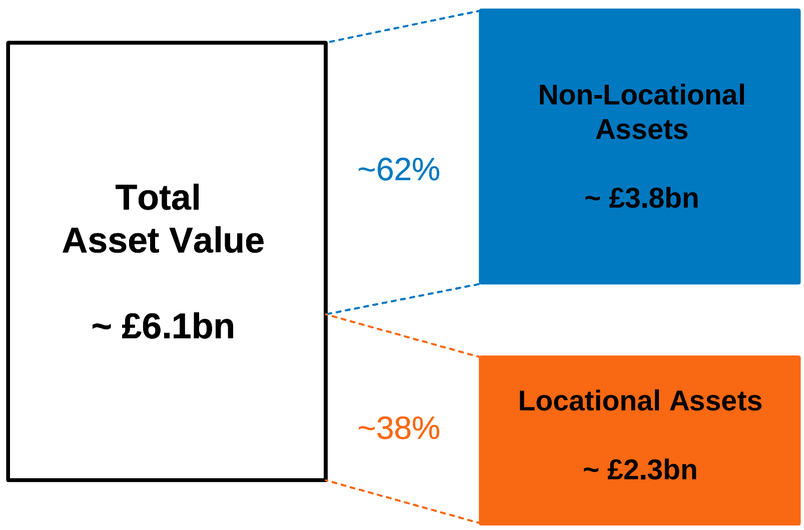
Whilst expressing a view on the issues raised in the GB ECM-13 pre-consultation document, the responses to the pre-consultation also highlighted a number of areas in which the industry considered that National Grid should undertake further analysis in order to ensure that the industry can make an informed decision on the treatment of the residual TNUoS generation tariff.

5.1 Residual revenue recovery

Historically, the locational element of TNUoS tariffs (for both generation and demand) has been used to recover in the region of 15-25 percent of MAR recovered from TNUoS charges, with the remaining 75-85 percent recovered from the respective residual tariffs for demand and generation. A number of respondents to the pre-consultation requested further analysis as to exactly what costs the residual tariffs are used to recover.

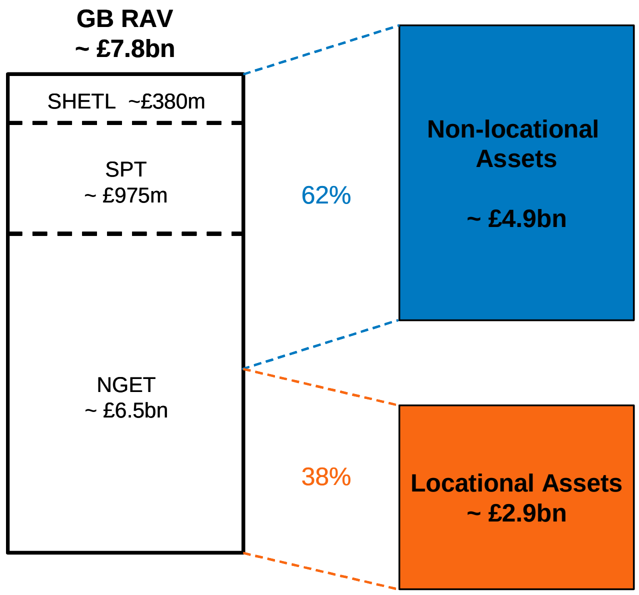
Figure 4 provides an approximate asset valuation for infrastructure assets of NGET based on current cost accounting information at December 2008. It identifies that approximately £2.3bn (38%) of transmission infrastructure assets can be classified as locational assets (i.e. towers, overhead lines and cables), whilst the remaining £3.8bn (62%) could be classified as non-locational assets (i.e. switchgear, transformers, protection equipment, land and buildings etc).

Figure 4 NGET asset valuation



Whilst it is reasonable to assume that such a split will vary for each of the TOs due to the differing network designs and topography of the respective networks, using these percentages of locational and non-locational assets as a proxy for the entire GB transmission system, Figure 5 provides an indicative split of the GB Regulatory Asset Valuation (RAV) for all three TOs within Great Britain.

Figure 5 2009/10 GB Regulatory Asset Valuation*

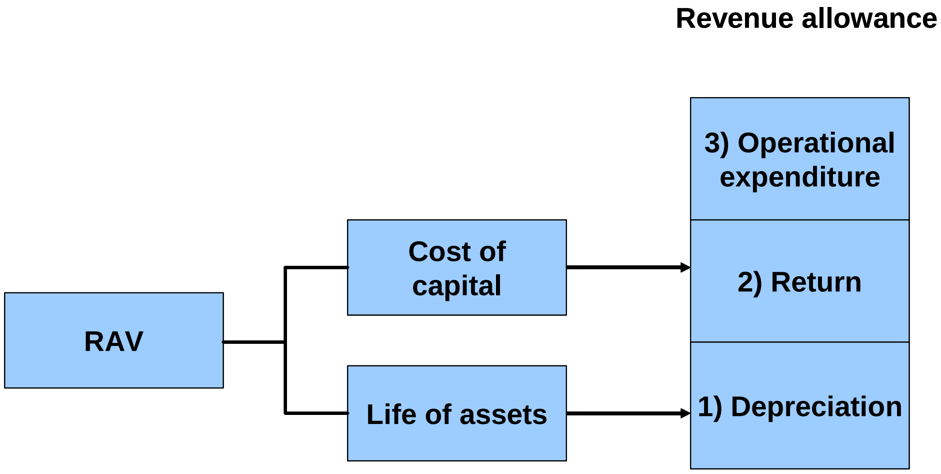


* Note that the figures (not percentages) used are based on those published in the *Transmission Price Control Review: Final Proposals*[9] document, in 2004/5 prices subsequently indexed into 2009/10 prices.

Based on a GB RAV of ~£7.8bn, a reasonable estimate of those infrastructure assets which could be considered as locational assets would be ~£2.9bn, with the remaining ~£4.9bn of assets classified as non-locational assets.

In determining a revenue stream for a price control period, a number of factors are taken into consideration by the Authority at the time of a Price Control Review (PCR). In its simplest form however, the main components of a revenue allowance can be considered as 1) an allowance for depreciation of the RAV; 2) an allowance to earn a rate of return on the capital expenditure invested in the RAV by the TOs; and 3) an allowance for operational expenditure. This is represented by Figure 6 below.

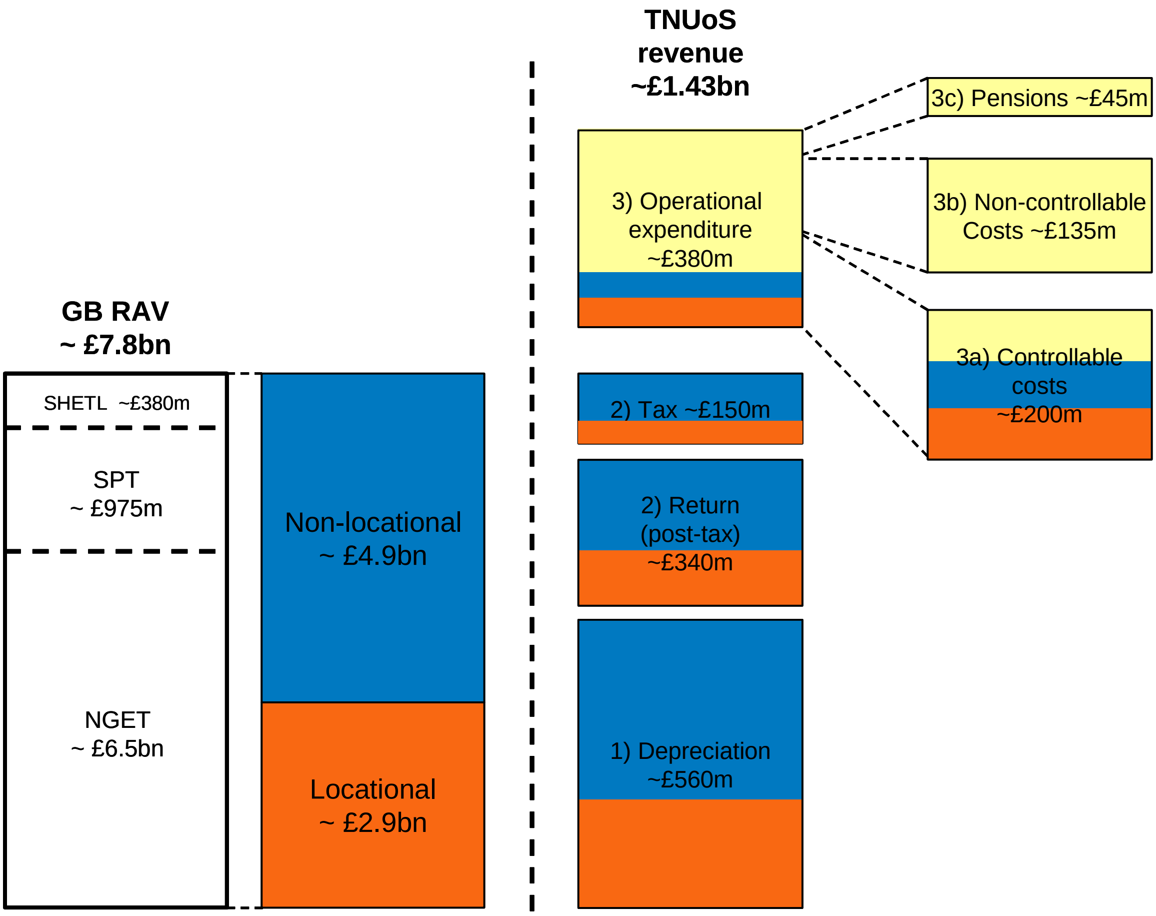
Figure 6 Revenue allowances



[9] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/16342-20061201_TPCR%20Final%20Proposals_in_v71%206%20Final.pdf

Using these three categories of revenue allowance, Figure 7 identifies an indicative revenue allowance to be recovered from TNUoS charges across Great Britain for 2009/10.

Figure 7 2009/10 GB RAV & TNUoS revenue



* TNUoS revenue figures are based on those published in the *Transmission Price Control Review: Final Proposals* document, in 2004/5 prices subsequently indexed into 2009/10 prices.

The first two elements of the revenue allowance (i.e. depreciation and return) are directly linked to the RAV and calculated based on the life over which each asset is depreciated, and the PCR-determined cost of capital allowances for each TO respectively.

A reasonable forecast of the allowance for depreciation in the 2009/10 charging year could be considered to be in the in the region of £560m. Of this, based on the principles adopted above, 38% could be considered as depreciation of locational assets (represented in amber), with the remaining 62% as depreciation of non-locational assets (blue).

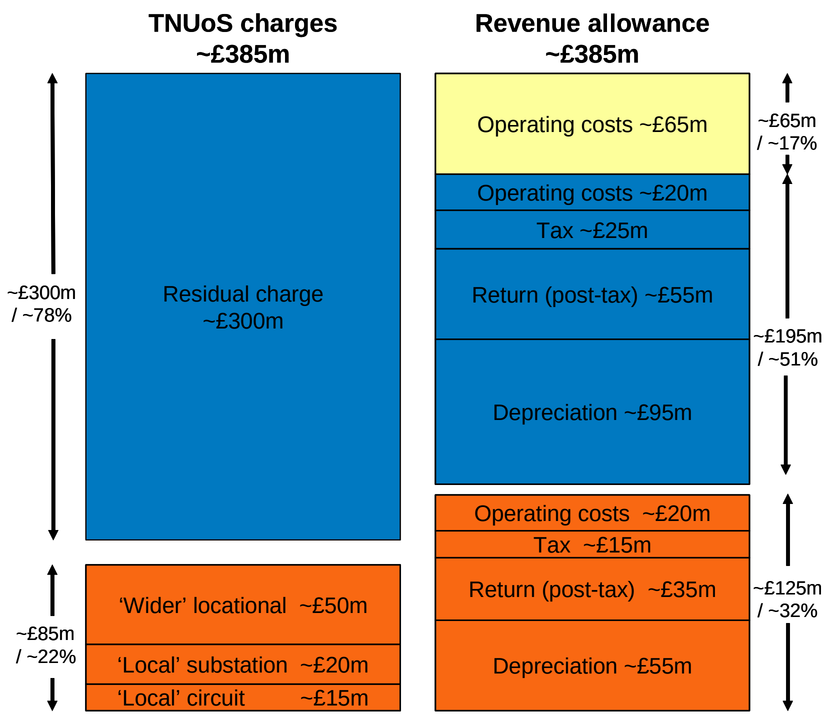
Whilst the return on the RAV is differentiated between a post-tax return and a separate allowance for taxation, the same approximation for both locational assets (amber) and non-locational assets (blue) can be made.

The third element of the revenue allowance is that of operational expenditure, which is not linked directly to the RAV and can broadly be separated into three categories:

- **3a) controllable operating costs.** These include direct or field activities such as inspection, maintenance and repair of networks, driven by asset replacement policies, technical standards, faults on the network, climatic and environmental factors. Also, indirect activities such as services which support field activities e.g. asset management, network design, finance, IT, HR and corporate costs. An element of these costs is included in the calculation of the expansion constant and therefore the locational TNUoS tariff (highlighted in amber), whilst a further element of these costs can be attributed to non-locational assets (blue). A proportion of controllable operating costs however, cannot be directly allocated to either classification of transmission asset (yellow).
- **3b) non-controllable operating costs.** These relate to business rates and licence fees and cannot necessarily be allocated to either classification of asset (yellow).
- **3c) pensions,** the costs of which cannot be directly attributed to either classification of asset (yellow).

TNUoS generation charges are responsible for recovering 27% of allowed revenue.[10] In order to provide an indication of what the residual element of the TNUoS generation charge is recovering, Figure 8 provides a comparison of the forecast 2009/10 TNUoS charges relating to generation only, and the forecast allowed revenue identified in Figure 7 above, pro-rated at 27% to reflect the proportion of revenue allocated to generation.

Figure 8 2009/10 Generation TNUoS vs Revenue



* Revenue allowance calculated based on 27% of those revenues identified in Figure 7, and subsequently differentiated between those costs which can be attributed to either locational, non-locational or neither classification of asset.

10 Whilst 27% of overall revenue is recovered from generation, 27% of the actual costs of the transmission system are not necessarily caused by generation.

In total, the locational element of TNUoS generation charges in 2009/10 is forecast to recover approximately 22% (~£85m) of overall revenue from generation Users, with the remaining 78% (~£300m) to be recovered from the residual element of the TNUoS generation tariff.

Approximately 32% (£125m) of generation revenue can reasonably be attributed to recovering the costs of investment in locational transmission infrastructure assets, with approximately 51% (~£195m) attributable to recovering the costs of investment in non-locational transmission assets. A further allowance in the region of 17% (~£65m) of generation revenue can be attributed to recovering operational expenditure including the cost of pensions, which are not necessarily attributable to either classification of asset.

Given that the 'wider' locational tariff is not designed to recover a proportion of revenue, but to provide locational signals based on tariff differentials (and the forecast of ~£50m of revenue derived from the wider locational charge is the net revenue recovered from both positive and negative generation charges), it is reasonable to assume that a proportion of revenue recovered in relation to locational assets is done so via the residual generation tariff.

5.2 Historic and 'lumpy' investment

Having noted in the GB ECM-13 pre-consultation that amongst other costs, the residual element of the TNUoS tariff recovers the cost of historic and 'lumpy' transmission investment, a number of respondents to the pre-consultation sought further quantitative analysis from National Grid as to exactly what this constituted.

Whilst it is difficult to identify exactly those assets which could be classified as 'lumpy' investment or those transmission investments made in the past for which their exact use today has since altered as a result of changes in the generation and demand background or further investment in transmission infrastructure, one approach to determine a reasonable proxy might be to use the measure of investment costs used in the DCLF ICRP Transport model, that of MWkm.

The DCLF ICRP Transport model used to calculate 2009/10 locational TNUoS tariffs is based on a total circuit flow of approximately 10.3 million MWkm,[11] based on an unsecured transmission network under winter peak conditions.

In order to reflect the additional security of the GB transmission network whereby demand can be met to Security and Quality of Supply Standards, a locational security factor of 1.8 is applied in the calculation of transmission tariffs. By applying this locational security factor to the total MWkm derived from the unsecured DCLF ICRP Transport model, the total MWkm on a secured GB transmission system to meet system peak demand could be considered to be a circuit flow of approximately 18.5 million MWkm.

Using DCLF ICRP Transport model network data (GB Seven Year Statement data), when multiplying the length of all locational assets (cables and overhead lines) by their winter peak capacity rating, this results in approximately 46.7 million MWkm of locational assets for the entire GB transmission system. Investment in locational assets required to meet the needs of today's transmission Users to Security and

[11] It should be noted that a number of approximations are made in the DCLF Transport Model such as the running of substations solid and the assumption of optimum capacity. If anything, these assumptions would result in a potential underestimation of marginal km.

Quality of Supply Standards could therefore be estimated to be in the region of approximately 40% of all locational infrastructure assets, whilst the remaining 60% of locational assets could be considered the product of both historic and lumpy transmission investment.

Building on the revenue allowance associated with locational assets identified in Figure 8, whereby it is identified that approximately £125m (32%) of revenues can reasonably be apportioned to locational transmission infrastructure assets, Figure 9 below further differentiates this into a revenue allowance for historic and lumpy investment in locational transmission infrastructure.

Figure 9 Generation revenue associated with historic and lumpy investment in locational transmission infrastructure assets

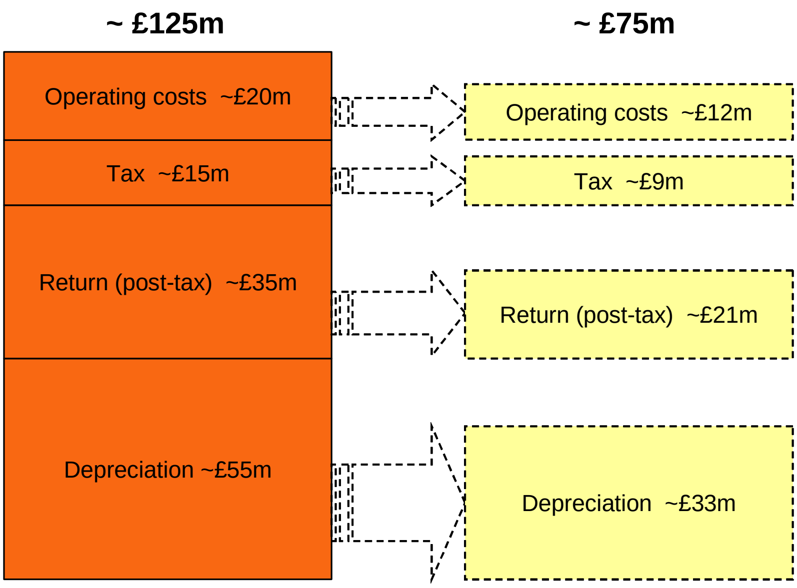
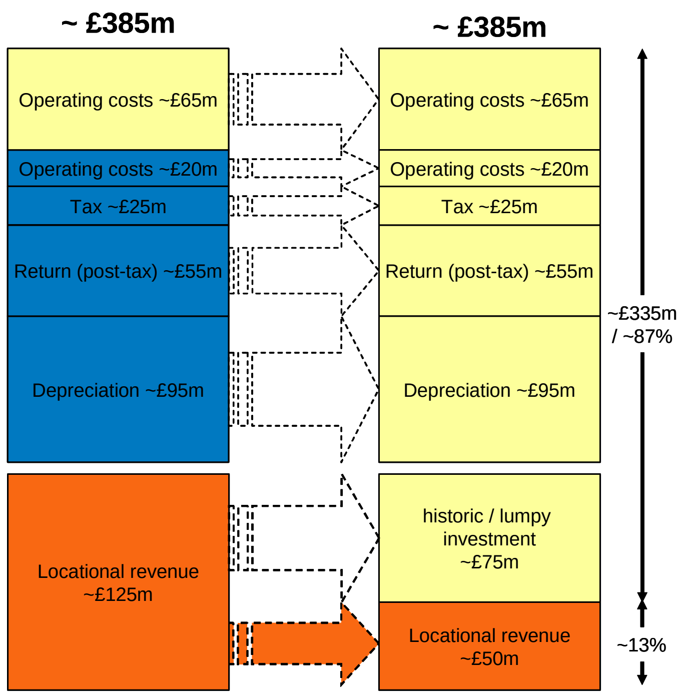


Figure 10 summarises the information presented in this Section, in that it might be reasonable to consider that approximately £50m (~13%) of transmission revenue from generation can be allocated to the investment in locational assets. The remaining ~£335m (~87%) can then be attributed to either the recovery of costs associated with transmission investment in non-locational assets, historic or lumpy investment in locational infrastructure assets or the recovery of operational costs which cannot be directly linked to any classification of asset.

Figure 10 2009/10 revenue recovery for locational assets



5.3 Transmission infrastructure investment

In response to the pre-consultation document, there were conflicting opinions presented with regard to the level of transmission infrastructure investment required to provide transmission access for generators of different fuel types and varying load factors.

A respondent noted that an allowance is currently made in the GB SQSS for generators of lower load factor in determining the level of infrastructure investment, whilst another respondent considered that there will not be any significant difference between the infrastructure built for plant operating at 40% load factor or one operating at 80% load factor.

GB SQSS – deterministic criteria

The GB SQSS is the standard for transmission planning used by the GB transmission licensees. The standard was established for a system predominantly supplied by conventional generation (i.e. thermal or hydro generation) and has provided the basis for the development of an economic and efficient transmission system over the years.

The current approach for determining required transmission capabilities is outlined in *Chapter 4: Design of the Main Interconnected Transmission System* of the GB SQSS[12]. The minimum transmission capability requirement is determined such that the transmission system can be designed to be able to provide sufficient capability without an unacceptable loss of supply or demand, unacceptable overloading of equipment, unacceptable voltage level levels, poor voltage performance margins or

[12] http://www.nationalgrid.com/NR/rdonlyres/FBB211AF-D4AA-45D0-9224-7BB87DE366C1/15460/GB_SQSS_V1.pdf

system instability. Capabilities are determined for N-1 and N-2 (N-D in Scotland) outage conditions to ensure system robustness against credible contingencies.

Transmission capability requirements are specified on a boundary basis where a boundary can be drawn anywhere on the system, providing it divides the transmission system into two contiguous parts. The required transfer capability is determined from two components, i.e. planned transfer and interconnection allowance. In order to determine the planned transfer, the system is set up in the planned transfer condition and generation is uniformly scaled down, proportional to its winter peak availability, to meet demand. The power flow across any given boundary is referred to as the planned transfer.

The interconnection allowance depends on the distribution of generation and demand on either side of the boundary and is primarily intended to cover for uncertainties in generation and demand. The overall aim of the transmission security standard is to ensure that the transmission system does not unduly restrict generation in securing demand and to facilitate market operation.

Wind generation is treated in the same manner as other generation in the calculation of planned transfer in the GB SQSS, except that a lower availability factor is used. To date, the transmission licensees have determined an appropriate availability factor of 72% for wind, which translates to a wind generation output of around 60% in the planned transfer condition. The availability factor for conventional generation meanwhile has been taken to be traditionally 100%, resulting in an output of 83% in the planned transfer.

Based on such percentages, it could therefore be considered to be true that investment in the MITS for wind generation could be less than that required for thermal generation plant based on the planned transfer condition. The design of the generation connection and local infrastructure however, would be the same regardless of plant type or load factor.

GB SQSS – economic assessment

In addition to the deterministic criteria, an economic assessment is performed under the GB SQSS throughout the year. This assessment seeks to establish the level of capacity associated with the minimum costs to the end consumer, taking into account all of the transmission licensees costs (infrastructure and operational). In August 2006, National Grid published a "*Report on GB charging condition 3: The treatment of intermittent generation in the charging methodology*" detailing the economic assessment process.[13]

In summary, the calculation of the economic level of capacity involves studying various scenarios that could reasonably be expected throughout a year, including variation to demand profiles, varying generation operating regimes, reasonably expected future generation patterns and the need for efficient and economic transmission circuit outages.

The economic assessment includes a number of operational costs including congestion costs, transmission losses and reactive utilisation costs, and the economic level of investment in infrastructure is established by comparing the net

[13] http://www.nationalgrid.com/NR/rdonlyres/459CB43B-5098-4F4E-9240-E969B713EE7B/9239/Condition3reportfinal.pdf

present cost of potential future compensation against the capital cost of increased infrastructure.

The report concluded that having reviewed the planning standard and being mindful of National Grid's wider licence obligations, particularly relating to non-discrimination, National Grid could find no evidence that intermittent generation consistently causes less investment on the transmission system than conventional generation.

The report considered that whilst it is true that intermittent generation does not provide an equivalent contribution to peak demand security, it does require equal access to the transmission system and it is the consequence of providing financially firm access, not the requirement to meet demand security criteria that drives the economic level of transmission investment.

6 Options

National Grid presented three potentially suitable options for the treatment of the residual TNUoS tariff for generation Users in the GB ECM-13 pre-consultation document for industry comment, namely:

1. **Commoditisation:** whereby the residual element of the TNUoS generation tariff is levied as a uniform charge on generation Users of the transmission system on a half-hourly metered generation basis (£/MWh) for every settlement period throughout the charging year.
2. **Local Capacity Nomination:** whereby the residual element of the TNUoS generation tariff is levied on a capacity basis on generation Users of the transmission system based on their 'Local Capacity Nomination' (£/MW).
3. **Daily Peak Generation:** whereby the residual element of the TNUoS generation tariff is calculated as a daily peak utilisation charge based on the metered generation over the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) every day over the charging year (£/MWh).

In light of views expressed in the ten responses which were received, National Grid considers that it is appropriate to give further consideration to each of these in this consultation document.

This section details each of the options and seeks to provide further information regarding two of the concerns which were raised in response to the pre-consultation document, namely that commoditised or daily peak generation tariffs could be highly volatile, whilst creating significant "winners" and "losers".

6.1 Commoditisation

6.1.1 Calculation of commoditised tariff (£/MWh)

The residual element of the TNUoS generation tariff would be levied on Users of all long and short-term access products proposed by the suite of CUSC amendments on a half-hourly metered utilisation basis. The tariff would be calculated by dividing the residual revenue recovery requirements from generation, by the forecast annual metered generation (in TWh) and then levied on a £/MWh basis across all generation Users based on their metered output for each half-hourly settlement period throughout the relevant charging year.

Based on forecast 2009/10 revenues identified in Table 1 below, assuming a forecast annual generation charging base of 327TWh, a commoditised residual tariff for generation would be in the order of £0.918/MWh (£300m / 327TWh = £0.918/MWh).

Table 1 Forecast 2009/10 revenue recovery

Tariff	Generation (£m)	Demand (£m)	Total (£m)
'Local' circuit	~15	N/A	~15
'Local' substation	~20	N/A	~20
'Wider' locational	~50	~130	~180
Residual	~300	~910	~1210

By moving away from charging for the residual element of the TNUoS tariff based on a generator's TEC, to levying the residual generation tariff based on utilisation, the annual charges levied on generation Users would vary dependent on load factor.

Using 2009/10 charging data, where the residual generation tariff for generation is ~£3.793/kW, the relationship between the annual TNUoS charge levied on a generator of any size is such that a generator with a load factor in excess of ~47 percent for the charging year would be subject to a greater annual residual charge than had that been levied based on TEC. The reverse is equally true for plant with an average load factor of less than ~47 percent. This is illustrated in Figure 11, using a 500MW generator as an example. It is important to note that regardless of load factor, the locational tariff remains the same for all plant as this continues to be levied on a capacity basis.

Figure 11 Impact of commoditisation on the residual charge of a 500MW generator

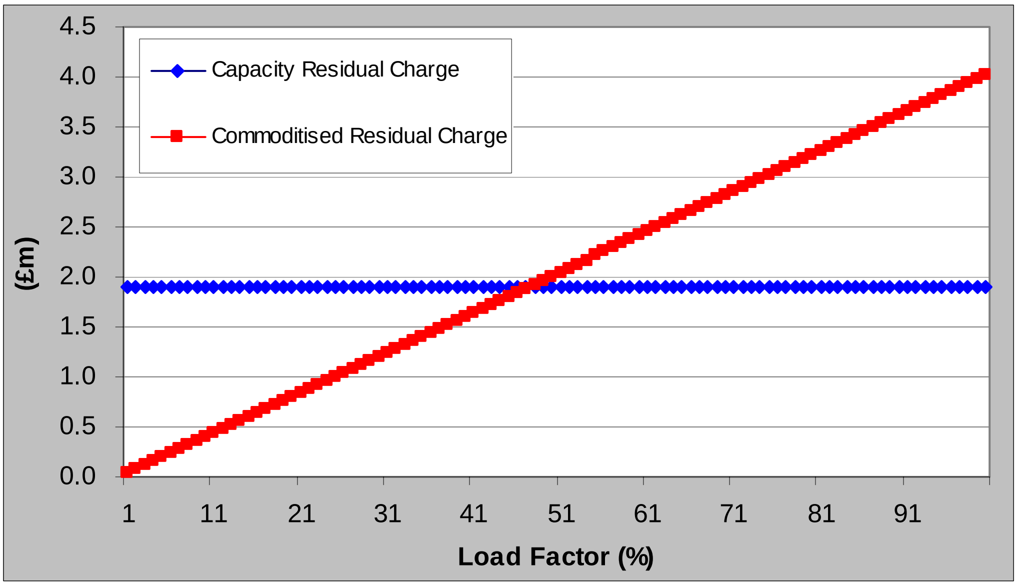


Table 2 identifies the basis upon which each of the elements of the TNUoS tariffs would be calculated and levied on Users of the GB transmission system with this option.

Table 2 Basis for calculating TNUoS tariffs

	Generation	Demand
'Local' circuit	Local Capacity Nomination (MW)	N/A
'Local' substation	Local Capacity Nomination (MW)	N/A
'Wider' locational	Long-term capacity booking (MW) (levied on triad metered generation for generation in negative tariff zones)	Triad peak demand (MW)
Residual	Annual generator output (MWh)*	Triad peak demand (MW)

** Annual metered energy output of a generator (MWh)*

6.1.2 'Volatility' of commoditised tariffs

A number of respondents expressed concern at the potential volatility of commoditised TNUoS generation tariffs. Table 3 provides an indication of commoditised residual tariffs (£/MWh) which would have been applied throughout Great Britain following the implementation of BETTA in 2005/6. Whilst the tariffs would have been calculated based on forecast volumes of energy rather than the actual data provided in the table, the information indicates that the calculation of tariffs based on energy rather than capacity does not necessarily result in greater volatility of tariffs.

Table 3 Residual TNUoS generation tariffs

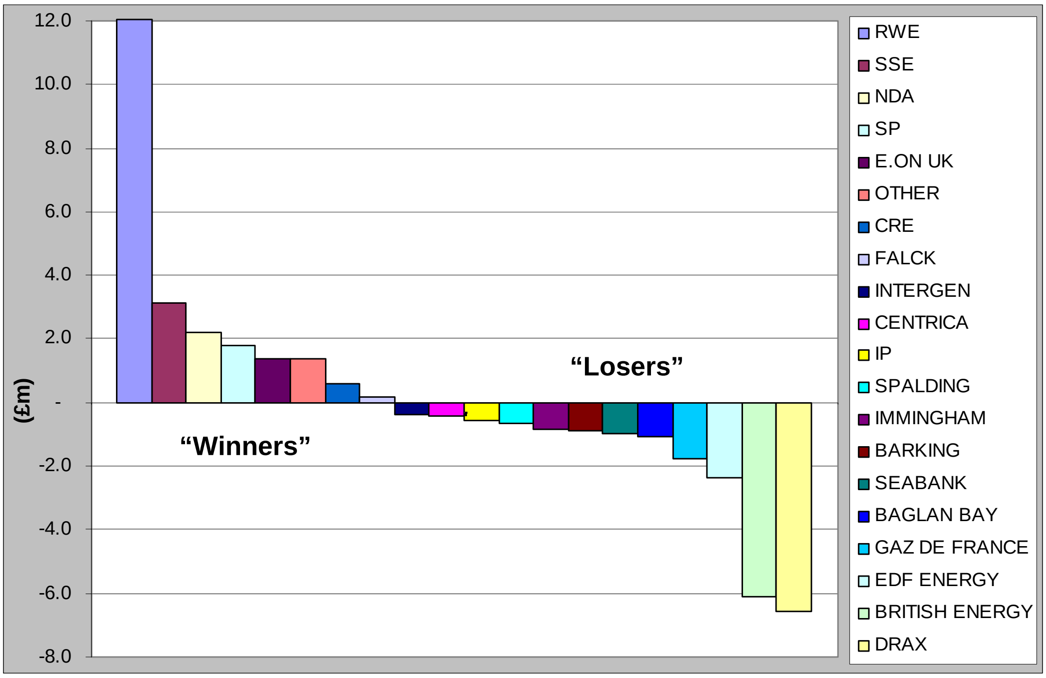
Charging year	Energy (TWh)	Residual Revenue (£m)	Commoditised residual tariff (£/MWh)	Actual residual tariff (£/kW)
2005/6	341	240	0.703	3.257
2006/7	331	265	0.801 (+13.9%)	3.550 (+8.9%)
2007/8	332	285	0.859 (+7.3%)	3.859 (+8.5%)
2008/9	*327*	315	*0.964 (+12.3%)*	4.108 (+6.8%)
2009/10	*327*	300	*0.918 (-4.8%)*	3.793 (-7.8%)

* Note – 2008/9 energy data is based on actual metered data up to and including 2nd February 2009. 3rd February to 31st March is forecast data, based on 2007 actual metered data. 2009/10 is forecast data based on 2008/9 data.

6.1.3 "Winners and Losers"

In response to the pre-consultation document, a respondent expressed concern that moving away from the current capacity regime towards a commoditised approach would create big winners and losers, dependent on a generators load factor. Based on 2007/8 metered data and the relevant 2007/8 tariffs from table 3 above, Figure 12 identifies those generation companies which would have "won" or "lost" under a commoditised charging regime in 2007/8.

Figure 12 Commoditisation: 2007/8 winners and losers



By moving away from a residual charging regime for generation based on capacity and implementing a commoditised residual charging regime based on a generators utilisation of the transmission system (£/MWh) throughout the charging year, some generation Users will experience significant changes to the their transmission charges, with some notable winners and losers.

6.2 Local Capacity Nomination

6.2.1 Calculation of tariff (£/kW)

The residual element of the TNUoS generation tariff would be levied on Users for all long and short-term access products based on their 'Local Capacity Nomination' (LCN), being the maximum volume (in MW) to which a generator is entitled to obtain either long or short-term transmission access products (including Overrun), which will not exceed the Connection Entry Capacity (CEC) of the generator. A more comprehensive definition of LCN and its properties is included as Appendix 1. It is important to note that the concept of LCN is being developed not specifically for the purposes of levying the residual generation tariff, but as a key element of the TAR.

In this option, the calculation of the residual generation tariff becomes simply the residual allowed revenue to be recovered from generation TNUoS, divided by the aggregated LCN across Great Britain in the relevant charging year. Based on a revenue recovery requirement of ~£300m and an LCN charging base of 81.8GW (assuming the total GB TEC of 2009/10 as a proxy for determining this), the residual TNUoS generation tariff based on this option would be ~£3.67kW.

Table 4 identifies the basis on which each of the elements of the TNUoS tariffs would be calculated and levied on Users of the GB transmission system with this option.

Table 4 Basis for calculating TNUoS tariffs

	Generation	Demand
'Local' circuit	Local Capacity Nomination (MW)	N/A
'Local' substation	Local Capacity Nomination (MW)	N/A
'Wider' Locational	Long-term capacity booking (levied on Triad metered generation for generators in negative tariff zones)	Triad peak demand (MW)
Residual	Local Capacity Nomination (MW)	Triad peak demand (MW)

6.2.2 'Volatility' of tariffs

By continuing to levy the residual TNUoS generation tariff on a capacity basis, the tariff remains a factor of the residual revenue to be recovered from generation Users, divided by the overall LCN charging base. As such, the tariff could only be considered volatile to the extent that allowed revenue to be recovered via the residual generation tariff changes and generation Users vary their LCN year-on-year.

6.2.3 Winners and Losers

By continuing to levy the residual TNUoS generation tariff on a capacity basis, this option would not create any notable winners or losers, on the assumption that a generator's LCN would broadly reflect its current level of TEC.

6.3 Daily Peak Generation

6.3.1 Calculation of daily peak generation tariff (£/MWh)

In this option, the residual TNUoS generation tariff would be levied on a generators metered generation volumes (MWh), calculated using the forecast metered generation by a generator for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) every day over the financial year, and subsequently reconciled based on actual metered data.

The tariff would be calculated simply by dividing the residual revenue recovery requirements from generation by the daily peak generation charging base (in TWh) and levied on a £/MWh basis across all generation Users based on their metered output for settlement periods 33 to 38 for each day of the relevant charging year.

Based on forecast 2009/10 revenues, assuming a daily peak annual generation charging base of 47TWh, a daily peak generation residual tariff would be in the order of £6.412/MWh (£300m / 47TWh = £6.412/MWh).

Table 5 identifies the basis on which each of the elements of the TNUoS tariffs would be calculated and levied on Users of the GB transmission system with this option.

Table 5 Basis for calculating TNUoS tariffs

	Generation	Demand
'Local' circuit	Local Capacity Nomination (MW)	N/A
'Local' substation	Local Capacity Nomination (MW)	N/A
Locational	Long-term capacity booking (levied on Triad metered generation for generators in negative tariff zones)	Triad peak demand (MW)
Residual	Annual generator output (MWh)* between settlement periods 33 to 38	Triad peak demand (MW)

** Annual metered energy output of a generator (MWh)*

For the purposes of a daily peak generation tariff, a range of periods could be considered as daily peak. A respondent to the pre-consultation considered that a 12-hour period (0700–1900) would be more appropriate to reflect the seasonal variation in periods of peak demand. National Grid welcomes the views of the industry on what might be the most appropriate daily peak period, with justification for any alternative recommended.

6.3.2 'Volatility' of daily peak generation tariffs

A number of respondents expressed concern at the potential volatility of a residual TNUoS generation tariff based on daily peak generation. Table 6 provides an indication of daily peak residual generation tariffs (£/MWh) which would have been applied throughout Great Britain following the implementation of BETTA in 2005/6. Whilst the tariffs would have been calculated based on forecast volumes of energy between 1600-1900 rather than the actual data provided in the table, the information indicates that the calculation of tariffs based on energy rather than capacity does not necessarily result in greater volatility of tariffs.

Table 6 Residual TNUoS generation tariffs

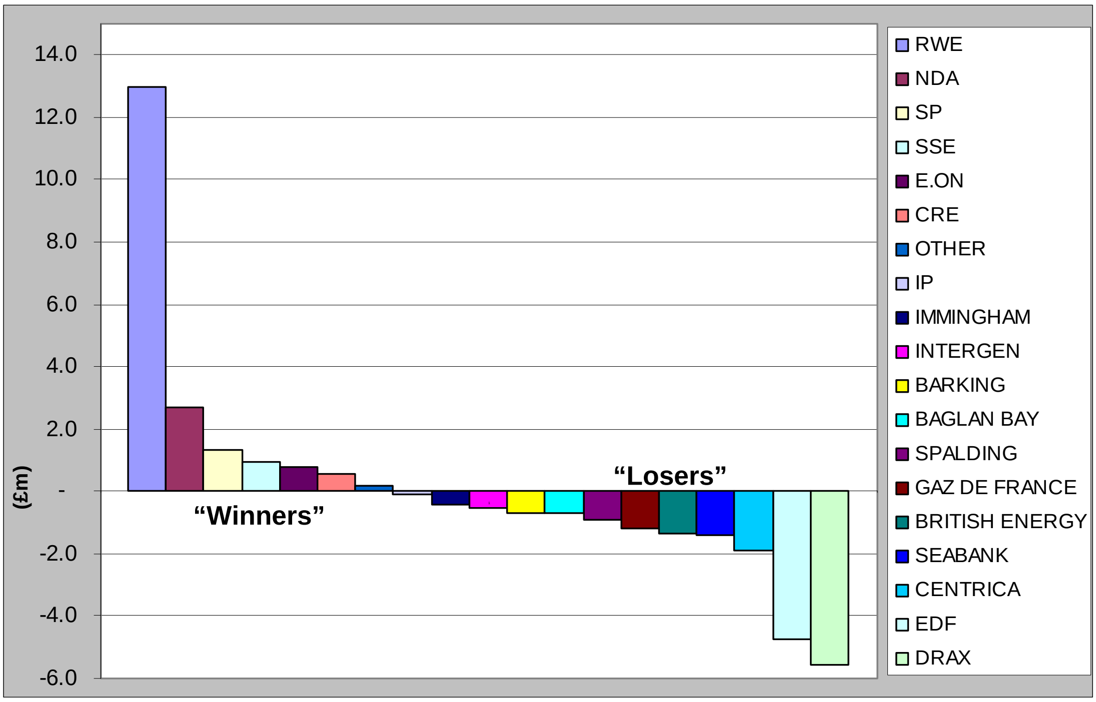
Charging year	Energy (TWh)	Residual Revenue (£m)	Daily peak tariff (£/MWh)	Actual residual tariff (£/kW)
2005/6	48	240	4.946	3.257
2006/7	47	265	5.610 (+13.4%)	3.550 (+8.9%)
2007/8	47	285	6.015 (+7.2%)	3.859 (+8.5%)
2008/9	*47*	315	*6.732 (+11.9%)*	4.108 (+6.8%)
2009/10	*47*	300	*6.412 (-4.8%)*	3.793 (-7.8%)

* Note – 2008/9 energy data is based on actual metered data up to and including 2nd February 2009. 3rd February to 31st March is forecast data, based on 2007 actual data. 2009/10 data is forecast based on 2008/9 data.

6.3.3 "Winners and Losers"

In response to the pre-consultation document, a respondent expressed concern that moving away from the current capacity regime towards a daily peak generation approach would create big winners and losers, dependent on a generators load factor between 1600 and 1900. Based on 2007/8 metered data and the relevant 2007/8 tariffs from Table 6 above, Figure 13 identifies those generation companies which would have "won" or "lost" under a daily peak generation charging regime in 2007/8.

Figure 13 Daily peak generation 2007/8 winners and losers



By moving away from a residual charging regime for generation based on capacity and implementing a charging regime based on actual utilisation during daily peak periods throughout the charging year, some generation Users will experience significant changes to the their transmission charges, with some notable winners and losers.

6.4 Calculation of monthly charges

In the event that either a commoditisation or daily peak charging option is to be implemented, there are a number of ways in which the resultant residual TNUoS generation charge could be calculated for generation Users on a monthly basis. This section presents two options for industry comment.

6.4.1 Monthly charge based on user forecast

One option for determining the monthly residual charge of a generator in the event that either the commoditisation or daily peak generation charging option was to be implemented, would be to develop a simple process similar to that of the calculation and levying of non-half hourly (NHH) demand charges.

This would require generation Users to forecast annual metered energy (either in total, or over the daily peak period) to be delivered onto the GB transmission system over the financial year. A Users annual residual generation charges would then be based on this forecast, multiplied by the relevant residual generation tariff (£/MWh) and split evenly over the 12 months of the relevant charging year. A draft template for the submission of generation forecasts is included as Appendix 2.

Example:

A 500MW generator forecasts that it will be generating throughout the charging year at an average load factor of 60 percent, therefore generating 2,628,000MWh of energy.

(500MW * 8760hrs) * 60% load factor = 2,628,000MWh

Having notified National Grid of this forecast, based on a residual tariff of £0.918/MWh, the annual charge for the generator will be initially forecast to be £2,412,504.

£0.918/MWh * 2,628,000MWh = £2,412,504

Divided equally into 12 months, the forecast monthly charge for the generator will be £201,042.

Users would then have the opportunity to vary their generation forecasts throughout the charging year and National Grid would revise the monthly residual generation charge by recalculating the annual charge based on the revised forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. In the event that a Users forecast significantly differed from National Grid's, National Grid would reserve the right to invoice the User based on National Grid's revised forecast. For NHH demand tariffs, this figure is currently set out in the CUSC as a variation of 20 percent from National Grid's forecast and this would seem an appropriate basis upon which to modify a Users generation forecast.

Residual generation charges would be reconciled in line with the current reconciliation process which exists for NHH demand, namely on or before 30th June in each financial year for the preceding financial year.

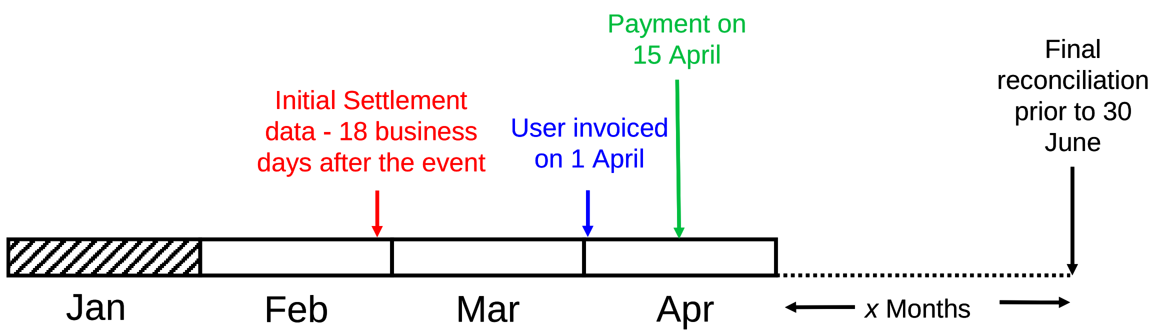
6.4.2 Monthly charge based on actual metered data

An alternative to calculating monthly charges based on User forecasts would be to implement a process similar to that currently used to calculate and levy Balancing Services Use of System (BSUoS) charges. On this basis, residual generation charges would be settled initially, based on available metered data and subsequently reconciled following the availability of the required metering data.

Based on the availability of initial metering data, a User could be required to pay the residual element of the monthly TNUoS generation charge approximately two and a half months after the event. A final reconciliation could then take place on an annual basis, perhaps in line with the current reconciliation process which exists for NHH demand, namely on or before 30 June in each financial year for the preceding financial year.

In the example provided in Figure 14 below, initial settlement data for a Users' residual generation charge for the month of January becomes available in late February (18 business days after the event). Given the short timescales involved, this is unlikely to be invoiced before 1st April, with subsequent payment required on 15th April. Final reconciliation would then take place prior to 30th June in the following charging year.

Figure 14 Monthly residual charge based on actual metered data



7 National Grid - initial view

Liability for short-term Users

National Grid considers that Users of both long and short-term transmission access products should be liable for the residual element of the TNUoS generation tariff as Users of either product benefit from access which has been provided as a result of historic and lumpy investment in both locational and non-locational transmission assets.

National Grid considers that it would be appropriate for Users of all forms of access to pay the full residual TNUoS generation tariff, not a proportion of it as suggested by some respondents to the pre-consultation. Those charging arrangements being developed for short-term access as part of the GB ECM-14 consultation process[14] are being developed without the inclusion of the residual element of the TNUoS generation tariff.

Residual revenue recovery

National Grid considers that it remains appropriate to levy the locational element of the TNUoS tariff on a capacity basis to provide efficient investment signals for generation projects to locate in areas of the transmission system which will minimise the level of investment required. This continues to be appropriate on the basis that the transmission investment required to provide a capacity-based access right is driven predominantly by the capacity of a generator applying to connect to the transmission system.

The analysis presented in Section 5 of this consultation identifies that the volume of revenue recovered from the locational element of the TNUoS tariff (historically 15-25 percent of MAR) is reasonably proportionate to the level of investment in locational transmission infrastructure assets. Whilst the residual element of the TNUoS tariff recovers a large majority of TNUoS revenue in the order of 85%, this could be considered to broadly correlate with the percentage of revenue derived from investment in non-locational assets, historic or lumpy investment in locational assets, and the recovery of operational costs which cannot be directly linked to any classification of asset.

Assessment of options against relevant charging objectives

As noted previously in Section 2 of this consultation, National Grid has an obligation to make such modifications to the Use of System charging methodology as may be requisite for the purpose of better meeting the relevant transmission Licence objectives, namely: to facilitate competition; for charges to be cost-reflective; and to take into account developments in the transmission business.

In setting and reviewing Use of System charges, National Grid has a number of further objectives contained in the Statement of Use of System Charging Methodology. These are to:

- offer clarity of principles and transparency in the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;

[14] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

- 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.

National Grid considers that all three of the options presented in this consultation for calculating the residual TNUoS generation tariff potentially better meet the relevant charging objectives, as represented in Table 7 below. The argument as to which option better meets the relevant objectives and effectively, whether the residual element of the TNUoS generation tariff should be calculated and levied on a capacity basis (£/kW) or an energy usage basis (£/MWh) are finely balanced and this is reflected in the industry responses to the pre-consultation document.

Table 7 Assessment of options against relevant objectives

Option	**Facilitates Competition**			**Cost Reflectivity**			**Developments in the transmission business**
	Transparency	Predictability	Stability	Services provided	Incremental	Practical cost	
Commoditisation	✓	✓	✓	✓	N/A	✓	✓
Local Capacity Nomination	✓	✓	✓	✓	N/A	✓	✓
Daily Peak Generation	✓	✓	✓	✓	N/A	✓	✓

Facilitating competition
Given that allowed revenue is known and the tariffs for each option would be calculated by dividing this by either annual or daily peak energy usage (taking into account transmission losses for generation) which varies year-on-year and is easily predictable, or a pre-notified LCN aggregated across Great Britain, from a facilitating competition perspective, the calculation of residual TNUoS generation tariffs for each of the three options could be considered to be transparent, predictable and relatively stable.

Moving away from a capacity-based approach for residual TNUoS charges for generation towards a utilisation-based approach in the form of either a commoditised charge or a daily peak generation charge could be considered as a significant step away from the current charging principles. In some respects, this could be considered to facilitate competition by encouraging marginal generators to extend their life and contribution towards security of supply on the basis that they are charged the residual element of the tariff only when they make use of the transmission system, whilst the same is true for new generation connecting to the transmission system of an intermittent nature. At the same time however, Section 6 of this document highlights that the implementation of either approach would result in significant changes to the proportion of the residual generation charge allocated to some generators, with notable winners and losers. On the basis of stability of tariffs for existing generation Users, this might not be considered to facilitate competition.

Cost-reflectivity
National Grid considers that the revenues associated with the residual TNUoS generation tariff reasonably reflect the costs of investment in non-locational assets, historic and lumpy investment in locational assets and operational costs which are

not directly attributable to any classification of asset. As such, it should be considered reasonable that these costs are socialised on the basis of the wider benefits which are provided to all generation Users.

In assessing which of the options presents the most cost-reflective solution for recovering these costs, the argument essentially boils down to whether the costs of the transmission system have been, and continue to be incurred entirely on a capacity basis to meet winter peak demand, or whether the transmission system is increasingly becoming a network with higher levels of plant capacity margin. National Grid considers that the TAR proposals increase use of the transmission system on a short-term basis (for which transmission access is likely to be available as a result of historic, lumpy and non-locational investment) and that the use of total winter peak capacity booked as a proxy for transmission investment may be coming less valid.

Developments in the transmission business
Given that each of the options presented have been developed as a result of the current TAR, National Grid considers that all three options should be considered as taking into account developments in the transmission business in that Users will potentially be increasingly making use of short-term access to the transmission system for which they should be levied with the residual element of the TNUoS generation tariff.

Preferred option
Considering all of the above, National Grid believes that it is appropriate at this stage for all three options presented to remain on the table for industry consultation given that all three should be considered to better facilitate the relevant charging objectives. On balance, if National Grid were to indicate a preferred approach, the option of a residual TNUoS generation charge based on a generators Local Capacity Nomination might be considered to be most appropriate at this stage on the basis that it represents least change to the current charging arrangements, meets the charging requirements for the purposes of the TAR and does not create significant winners or losers in the generation business. If issues were to be encountered following the implementation of the LCN option, the basis of calculating and levying the TNUoS generation tariff could be reassessed in due course.

Calculation of monthly charge
In the event that either the commoditisation or daily peak generation option is implemented, National Grid considers that a monthly charge based on generation forecasts is the most appropriate basis upon which to calculate a generators monthly charge.

Whilst some generation Users would argue that this is potentially a complex process and that it is difficult to forecast energy production, National Grid considers that this is in fact a relatively simple process which currently works well for NHH demand Users and provides sufficient scope for either a generator or National Grid to revise the forecasts as and when necessary. In addition, a residual charge based on User forecasts would eliminate the security requirements on generation Users which would otherwise be required if charges were to be levied in arrears based on actual metered data.

TNUoS revenue split
Given that the TAR Working Groups all proceeded on the basis of a 27/73 revenue split and that it is not essential to review the existing G/D split at this time, the GB ECM-13 consultation process will not give further consideration to this issue.

Over / under recovery

National Grid considers that whilst the issue of over / under recovery is a valid concern which may require further consideration by the industry at some point, it is not intended that the treatment of over-recovery of revenue from generation will be addressed as part of the GB ECM-13 consultation process. Instead, this will be considered as part of an independent consultation in the future, in the event that over-recovery becomes a possibility through the implementation of any of the Amendment Proposals, particularly CAP166: Long-term Entry Capacity Auctions.

8 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, responses must be received by close of business on **Tuesday 31st March, 2009**.

Comments are particularly welcome regarding:

- The appropriateness of a capacity or utilisation based charge for calculating the residual element of the TNUoS generation tariff, for either all or part of the residual revenue.
- Consideration of a more appropriate period on which a daily peak generation charge should be based, with justification.
- The analysis presented in Section 5 of this consultation.
- The options presented for the calculation of monthly charges.

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

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

Craig Maloney
Electricity Charging & Access Development
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 Craig on 01926 655896.

APPENDIX 1 Local Capacity Nomination

For the avoidance of doubt, the concept of LCN has not been developed purely for residual TNUoS generation charges purposes. The concept of LCN is required to facilitate the suite of CUSC Amendments (CAP161-166) but in the context of residual charging, LCN presents a capacity definition which could be used for charging in the absence of TEC.

To put LCN into a wider context, the text below is an extract from the *CAP163: Entry Capacity Sharing* Amendment Report which is available on the National Grid website: http://www.nationalgrid.com/NR/rdonlyres/4B5CEDC8-EE1A-44BE-B259-91D128DA6E90/31046/Cap163AmendmentReportVol1Issue1combined.pdf

Local Only Connections

5.81 The arrangements for local connections were developed by Working Group 3, and the conclusions are described below.

Definition of Local Capacity Nomination

5.82 Working Group 3 proposed that for generators with local only connections, a local access product should be developed. This concept, the Local Capacity Nomination (LCN) would be the maximum capacity (in MW) to which a generator is entitled to obtain transmission access products (long-term and short-term access products and overrun) within a charging year. It was also identified that it must not exceed the Connection Entry Capacity (CEC) of that generator to avoid damage to local transmission assets.

Summary of the properties of Local Capacity Nomination

5.83 LCN was determined by Working Group 3 to have the following properties:

- LCN is the term used by a generator to notify National Grid of its desired maximum local capacity holding in a transmission charging year;
- LCN represents the physical (and contractual) cap on the total generators' transmission access (MW) derived from a combination of all long and short-term transmission access products, including overrun;
- LCN will not exceed a generator's CEC;
- LCN is defined on a Power Station basis (consistent with TEC);
- LCN will be allocated on a first-come-first-served basis;
- LCN will be the basis upon which a generators' local asset charge will be calculated and levied;
- LCN is shareable between generators, when multiple generators agree to share. Any sharing arrangement would be managed with a clause which, in the case of two generators sharing, would restrict one generator if the other generator is using the local connection capacity and vice versa. This approach is similar to that currently adopted to deal with design variation connections.

Enduring arrangements for existing LCN holders

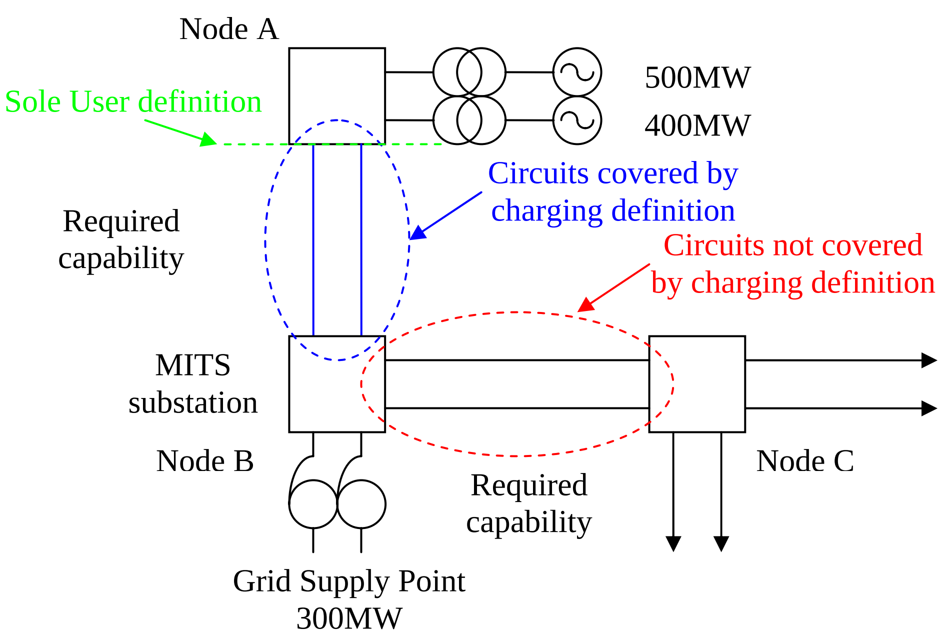
5.84 Working Group 3 debated as to whether LCN should be a finite right, linked (or not) to the period of firm transmission capacity obtained in an auction, or evergreen. Given that a generator may not wish to obtain long-term capacity through an auction process, it did not seem appropriate to link LCN to capacity obtained through the auction.

5.85 Working Group 3 considered that evergreen rights would be appropriate provided the definition of local assets is generally limited to “sole use” assets; i.e. local assets are not shareable. Where local assets (which are not shared) come to the end of their life, the TO could determine whether they should be replaced following bilateral discussions with the relevant generator. It was noted that the proposed charging definition of local works included shared use assets in some circumstances and some Working Group members believed that it might be appropriate to change the definition of local assets in these circumstances in order to ensure that they are not shared.

5.86 The problem with the “sole use” approach to local assets is that it may not in all circumstances be consistent with the principle of ensuring that Users which purchase short-term access products or share, make an appropriate contribution to the cost of the assets that are provided to facilitate their connection. If a “sole use” definition of local assets were to be adopted, then the cost of “spur” circuits to entry points with multiple generators will not be based on LCN (in MW). In the extreme circumstance of a generator choosing a “local only” connection at an entry point at which other generators are connected, that generator would not make any contribution to the cost of the transmission assets required to provide their connection.

5.87 This is shown in the below diagram. If a “sole User” definition were to be applied (this is represented by the dotted green line), neither generator would make any contribution to the cost of the spur (shown by the blue lines) required solely to provide their connection.

Potential Definitions of Local Works



5.88 The Working Group therefore concluded that local assets should not be limited to “sole use” assets. The Working Group considered that an alternative approach would be to use the definition from the “local generation charging” proposals contained in National Grid’s GB ECM-11 Conclusions

Report, which is that local circuits are those between an entry point and the next Main Interconnected Transmission System (MITS) substations, where a MITS substation is defined as a Grid Supply Point with more than one circuit connected or a substation with more than four transmission circuits connected. In the diagram above, these local circuits are highlighted in blue.

5.89 In this simplified example, the circuits between node A and the next MITS substation (node B) would be defined as "local" under the charging definition. This means that the generators at node A would get access once these circuits had been reinforced to provide a secure capability of 900MW. However, the circuits between node B and node C would not be covered by the charging definition of "local". This would lead to a permanent restriction to the output of the generators unless these circuits were reinforced to provide a secure capability of at least 600MW.

5.90 As described in **Error! Reference source not found.** above, the Working Group originally considered that different charging and CUSC definitions of "local" works may be required to:

- o Avoid circumstances in which there would be a permanent output restriction on generators being connected; and
- o Protect individual generators from the actions of others or the decisions of the Transmission Owners.

5.91 On 10th November, Working Group 3 reviewed the consultation responses, allowing further discussion to be undertaken. The Working Group expressed concerns associated with different charging and CUSC definitions of "local" works. The Working Group noted that if the CUSC definition leads to reinforcement works that go beyond the next MITS substation in order to avoid permanent restrictions, then a user with LCN only will essentially be getting transmission access without paying the associated cost reflective charge.

5.92 Based on this concern, the Working Group agreed that the charging definition for local works should be consistent with the CUSC definition. The Working Group noted that there were scenarios where this definition could lead to a permanent output restriction being placed on a generator and that this would be reflected in bids for short-term access being turned down, restricted sharing exchange rates and high overrun prices. The Working Group also noted that the proposals for node-to-node sharing arrangements would allow generators in this position to apply for node-to-node access rights to facilitate sharing with other generators.

5.93 One Working Group Consultation respondent expressed concern that the initial view was to define LCN as a finite right, stating that generally local assets should not be shareable with other generators and that finite right arrangements are only required to redistribute assets that are no longer required by a User but can be used by other generators. During the final Working Group 3 meeting, the majority of Working Group 3 agreed that an enduring right approach was appropriate for sole user assets. National Grid completed some further analysis of the existing system and concluded that, given the relatively shallow nature of local works as defined, there were very few instances in which an enduring LCN right could risk causing inefficient investment of delays to the entry of new power stations.

5.94 It was acknowledged that since it is a feasible circumstance that multiple Users may wish to share LCN and the associated local assets, arrangements would be required to facilitate this. Working Group 3 agreed that this could be dealt with by including access restrictions in the generators connection agreement. This is similar to the treatment currently used to deal with connection design variations. The Transmission Owner would build sufficient local assets to cope with the shared holding of LCN only.

5.95 In summary, it was agreed that a local works definition based on the charging description of a MITS substation used in GB ECM 11 should be adopted. Interpreting this into a definition of works rather than a boundary leads to:

Local works are the **Transmission Reinforcement Works** that are required from the **Connection Site** to connect in to a MITS substation, inclusive of substation works, where a MITS substation is defined as:

- A **Grid Supply Point** connection with 2 or more **Transmission Circuits** connecting at the substation; or
- More than 4 **Transmission Circuits** connecting at the substation,

For the purposes of this definition, for an **Embedded Power Station** the **Connection Site** is the associated **Grid Supply Point** as defined in the **Bilateral Agreement**

Application processes

5.96 **New connections:** Existing applications for new generation connections are progressed in line with Section 2.13 of the CUSC: *New Connection Sites, based on the desired CEC and TEC of the applicant.* Following any implementation of one or more of the suite of CUSC Transmission Access Review Amendments (CAPs 161-166), it is foreseeable that a generator may wish to obtain only short-term access products following connection. Given that a generators LCN will determine the level of obtainable short-term (and long-term) transmission access, and provide the basis upon which the TO decides on an economic level of transmission investment, the concept of LCN needs to be introduced into CUSC Exhibit B*: Connection Application*. A connection application will then be progressed under the same process as any other connection application.

5.97 **Existing connections wishing to increase LCN:** Section 6.30.2 of the CUSC: *Increase in Transmission Entry Capacity* defines the process by which generators can currently apply to increase their TEC. Any request from a User to increase its TEC for a connection site up to a maximum of its CEC is deemed to be a modification. This approach also appears appropriate for Users wishing to apply for an increase in LCN. In the event that multiple generators were sharing LCN, the application would have to be made on behalf of all of the generators involved.

5.98 **Application fees:** Given the proposed changes to the transmission access regime, it is considered appropriate that the current application fees included in the Statement of Use of System Charges, should be reviewed to differentiate between connection, local, and wider transmission system applications. Fixed and variable application fees will remain in operation. The Working Group noted in particular that generators wishing to increase LCN above their current TEC level during transition should not be exposed to the full Modification Application fee currently associated with changes in TEC.

5.99 **Pre-commissioning user commitment:** Working Group 3 identified that there are a number of potential options for arrangements to provide pre-commissioning user commitment:

- Cost-reflective final sums liabilities (possibly capped at the original offer);
- A liability based on the relevant Unit Cost Allowance (UCA); or
- A liability based on a multiple of the local generation TNUoS tariff.

5.100 Working Group 3 concluded that the requirement for pre-commissioning security associated with increases in LCN should be consistent with the arrangements proposed for wider long-term transmission access under CAP165.

5.101 The CAP165 Original proposal for wider rights is a liability that ramps up over the 4 years prior to completion, to a total of 8 times the wider generation TNUoS tariff. This is reflected in the minimum booking of wider access rights to apply post-commissioning. The 8 years is derived from analysis of TNUoS tariffs against wider UCAs, which shows that, on average, the UCAs are 15 times the TNUoS tariffs. The 15 is halved to reflect a 50/50 risk sharing between generators and consumers. Consistency would imply that the same multiplier could also be used for local connections.

5.102 However, there is an additional rationale for 8 years being an appropriate multiplier: If local TNUoS was exactly reflective of capital costs, then a capital payment of 8 x annuitised TNUoS would cover 50% of the capital costs. This is because the TNUoS methodology converts capital sums by assuming a 50 year asset life and a 6.25% rate of return. Annual sums can be converted into a capital sum by multiplying by:

$$(1-(1+0.0625)^{-50})/0.0625 = 15.22$$

5.103 If the 50% risk sharing, consistent with the CAP165 treatment for wider access is applied, the result is a multiplier of 8.

5.104 Local TNUoS would not recover all costs, due to Users paying for what they are using rather than what is installed. It therefore would seem appropriate that security is also provided on this basis, and that security should not be provided for TO investments made for wider system reasons.

5.105 The Working Group therefore concluded that, consistent with the CAP165 original treatment for wider access, pre-commissioning User commitment for local commitment should be based on a multiple of 8 years of local generation of TNUoS, profiled 25%/50%/75%/100% over the 4 years prior to completion.

5.106 Termination or reduction of the requested LCN would therefore result in the levying of a Local Capacity Reduction Charge, based on Local Cancellation Amounts. The Local Capacity Reduction Charge would be non-refundable.

5.107 The Local Cancellation Amount in each year would be a percentage of the Local Termination Amount, which is the higher of zero and eight times the relevant local generation TNUoS charge. The Local Capacity Reduction Charge would therefore be calculated as:

$$\textit{Local Capacity Reduction Charge} = LCN_r \times LCAM_t$$

Where:

- LCN_r is the reduction in Local Capacity Nomination in kW.
- $LCAM_t$ is the relevant Local Cancellation Amount which varies according to the number of full years from the Completion Date:
    - In the year prior to the Completion Date (i.e. t) *LCAM = LTA x 100%)*, where LTA is the Local Termination Amount;
    - Where t=-1, *LCAM = LTA x 75%*;
    - Where t=-2, *LCAM = LTA x 50%*; and
    - Where t=-3, *LCAM = LTA x 25%*.

Local Termination Amount = Max (0, ($LocGenTNUoS_n$ *x X))*

Where:

- $LocGenTNUoS_n$ is the relevant nodal Local Generation TNUoS tariff applicable to the generation project and published in the Statement of use of System Charges. If such a nodal tariff is not currently published, then the appropriate tariff will be calculated by National Grid as part of the application process, in accordance with the Charging Methodology.
- *X* is a multiplier, initially taking the value 8, although it may be appropriate that this be amended in subsequent price control periods.

5.108 Local Cancellation Amounts will be calculated using the prevailing local Generation TNUoS tariff at the time of Capacity Reduction. Capacity Reduction Charges would not apply to projects where there are no transmission asset works.

5.109 **Pre-commissioning security:** The introduction of generic Local Capacity Reduction Charges, defined in the CUSC to replace the existing final sums regime, defined in the bilateral Construction Agreements, will also require the introduction of provisions to define the level of financial security that should be held in relation to these potential liabilities.

5.110 It is therefore to add the applicable Local Cancellation Amount to each User's Security Requirement, as defined in paragraph 3.22 of the CUSC. To the extent that these amounts exceed the Allowed Credit extended to each User, Security Cover will need to be provided to National Grid, in any of the forms prescribed in the CUSC.

5.111 Working Group 3 noted that alternatives to the CAP165 Original amendment proposal had also been developed by Working Group 2, including cost reflective final sums liabilities. The Working Group noted that should these CAP165 alternative amendments be approved, then they would also amend the pre-commissioning liabilities and security associated with LCN to be cost reflective final sums liabilities,

5.112 **Existing connections wishing to decrease LCN:** Section 6.30.1 of the CUSC: *Decrease in Transmission Entry Capacity* defines the process by which generators can currently reduce their TEC. Essentially, a User is entitled to decrease its TEC giving five business days notice in writing, prior to the 30 March in a financial year, with that notified decrease in TEC taking effect on 1 April of that same year. The Working Group also noted the discrepancy between the late March deadline and National Grid's requirement for charge setting data to be provided no later than 23rd December in the previous (charging) year. Had the Working Group decided to pursue an evergreen approach, it would have recommended an alignment of the notification timescales associated with TEC / LCN reduction with the TNUoS charge-setting process.

Transitional arrangements to LCN

5.113 Working Group 3 considered three options for transition from the current arrangements to those which require a Local Capacity Nomination.

- LCN based on a generator's CEC
  Given that CEC is not currently linked to transmission access allocation, this option seems the least appropriate.
- LCN based on a generator's TEC
  Given that the suite of CUSC Transmission Access Review Amendments (namely CAPs 161, 162, 163, 164, 165 and 166) are potentially introducing some fundamental changes to the way in which transmission access is allocated, existing TEC may not be considered appropriate for some generators.
- Generators would notify National Grid of its desired LCN in advance of a pre-defined date
  Working Group 3 concluded that this option appeared to be the most practical solution, although it was noted that the value notified will be limited to a generators CEC. In the event that a generator did not notify National Grid of its desired LCN, the use of TEC as a default value seemed appropriate. In the instance that multiple generators wish to share an LCN, a process for request will be required. Timescales for a generator to notify National Grid of its desired LCN value will be very much dependent on the transmission access products implemented.

APPENDIX 2 Generation forecast submission

nationalgrid

GENERATION FORECAST SUBMISSION

Used for Calculating 2010/11 Monthly Residual TNUoS Charges

Company Name:

Company Registered No:

Contact Name:

Power Station Name	Forecast Energy (MWh)
Power Station 1	
Power Station 2	
Power Station 3	
Power Station 4	
Power Station 5	

Notes:
Forecasts should be returned to generation.submissions@uk.ngrid.com no later than 12 March 2010.
Forecast energy is the sum of energy generated over settlement periods 1-48 for each day of the financial year.
Only positive values of energy should be forecast.
The company name should be for the relevant CUSC party – the registered number is required to avoid confusion arising from differences between CUSC Party, parent/subsidiary companies and trading names.