

PRE-CONSULTATION DOCUMENT

GB ECM-13

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

**October 2008
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1 Executive summary

This pre-consultation document explains the options considered by the Transmission Access Review (TAR) Working Group 3 for National Grid's proposal 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).

For the avoidance of doubt, this pre-consultation does not propose any changes to demand tariffs, and it is the intention that the locational element of the TNUoS tariffs 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.

The document has been published on the National Grid charging website at the following address:

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

Following discussion at the TAR Working Group 3, this pre-consultation presents three potentially suitable options for further 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).

The Working Group considered that each of the three options presented, better meet National Grid's relevant Transmission Licence obligations with regard to transmission charging, and invites industry views on this.

Given the significant volume of live industry consultation resulting from the TAR at present, this pre-consultation has an extended period for response of 8 weeks. Comments should therefore be emailed to craig.maloney@uk.ngrid.com no later than **Thursday 4th December, 2008**.

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 pre-consultation document is to 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 tariff with a view to better meeting the relevant Transmission Licence objectives set out above, and invite industry views on those options presented.

3 Background

3.1 Transmission Access Review (TAR)

National Grid presented a suite of CUSC Amendment Proposals to the CUSC Amendments Panel meeting on Friday 25th 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** proposes 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** proposes to create a commercial mechanism for dealing with a generator's export over and above its total transmission access holding;
- **CAP163: Entry Capacity Sharing** proposes 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** proposes 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** proposes 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** proposes 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.

This pre-consultation presents, for industry comment, a summary of the options discussed by the Working Group regarding point 1 above, 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 TO's 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)”¹

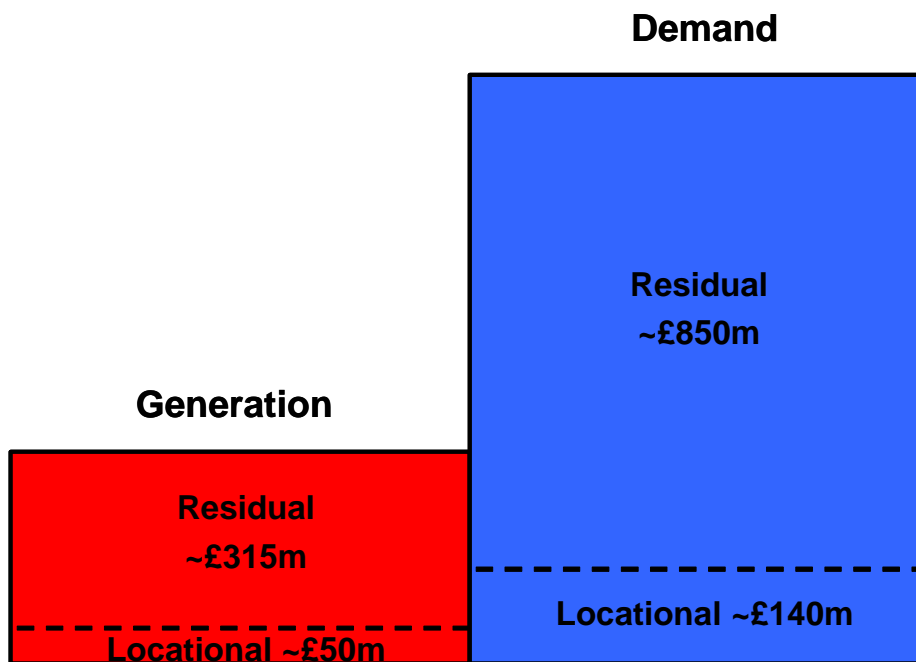
The underlying rationale behind TNUoS charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the 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 (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 recovers the appropriate proportions of its MAR through TNUoS charges for 2008/9 (of ~£1.35bn), is provided in Figure 1.

Figure 1 2008/9 TNUoS revenue recovery



¹ http://www.nationalgrid.com/NR/rdonlyres/58084876-C547-4099-A5EC-4E8E6A09D825/26767/Scanjob_20080528_105159.zip

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 and non-locational (i.e. substation) assets for which the current residual tariff is used.

3.3 Interaction with 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, the Working Group considers that it will no longer be 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 will 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.

Working Group 3 believes that it is therefore appropriate that Users of both long-term and short-term access should be subject to the residual element of the TNUoS generation tariff which is used to recover the costs of the assets that provide this access, for which this pre-consultation presents three options for industry comment.

3.4 European tariffication guidelines

In addition to the relevant licence obligations outlined in Section 2 of this document, National Grid and the Working Group is also mindful of European tariffication guidelines.² 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 ~£370m is recovered from generation Users in 2008/9, with an 'energy injection' of ~330TWh, the 'average G' charge from TNUoS equates to ~£1.05/MWh. Given current exchange rates in the order of 1.25 Euro / £³, the 'Annual national average G' for Great Britain, maintaining the existing 27/73 percent G/D split is comfortably within these guidelines at ~€1.31/MWh.

² <http://www.nationalgrid.com/NR/rdonlyres/CA7F2638-AF19-4BD5-A7E6-7143C274E120/25946/ETSOTariffsGuidelines.pdf>

³ Source: Bank of England, July 2008

National Grid and the Working Group did not consider that an amendment to the G/D split should be considered at this time, but welcome comments from the industry on this subject.

3.5 Interaction with recovery of Maximum Allowed Revenue

It should be noted that 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 Working Group 3. 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-013 consultation process. Instead, this will be considered as part of an independent consultation in the future, the event that over-recovery becomes a possibility through the implementation of any of the Amendment Proposals, particularly CAP166: Long-term Entry Capacity Auctions.

In addition, National Grid has recently issued a Conclusions Report to the Authority (GB ECM-11) regarding the charging arrangements for generator local assets.⁴ In the event that the modification is implemented, this will have an impact of reducing the amount of revenue to be recovered from the residual TNUoS generation tariff. Based on 2008/9 charging data, this is expected to be in the order of ~£25m, which would have resulted in a reduced residual revenue recovery of ~£290m compared with ~£315m.

4 Options

Working Group 3 gave consideration to a range of options which might be considered as proportionate solutions in ensuring that Users of short-term access are responsible for an appropriate share of the residual TNUoS generation tariff. This Section presents the three options which were most favoured by members of the Working Group in the form of:

1. **Commoditisation:** Was presented as the basis for residual charging for each of the CUSC Amendments as drafted, whereby the residual element of the TNUoS generation tariff is levied as a uniform charge on all 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:** An alternative developed by the Working Group, whereby the residual element of the TNUoS generation tariff is levied on a capacity basis on all generation Users of the transmission system based on their 'Local Capacity Nomination' (£/MW).
3. **Daily Peak Generation:** An additional alternative developed by the Working Group, whereby the residual element of the TNUoS generation tariff is calculated as a daily peak utilisation charge based on the metered generation for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) every day over the charging year (£/MWh).

⁴ http://www.nationalgrid.com/NR/rdonlyres/27F920CA-C678-4D91-A3D1-701E909BDAFB/28281/GBECM11ConcReport_final_HR.pdf

4.1 Commoditisation

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 2008/9 revenues identified in Table 1 below, assuming a forecast annual generation charging base of 330TWh, a commoditised residual tariff for generation would be in the order of £0.95/MWh assuming that the existing 27/73 G/D split is maintained (£315m / 330TWh = £0.95/MWh).

Table 1 2008/9 revenue recovery

Tariff	Generation (£m)	Demand (£m)	Total (£m)
Locational	~50	~140	~190
Residual	~315	~850	~1165

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 total annual charges levied on generation Users would vary dependent on load factor. Table 2 summarises the impact on the annual TNUoS charge using 2008/9 tariffs, for a 100MW generator in six different TNUoS generation zones, for three different load factors; 100%, 65% and 30%.

Table 2 Impact of commoditisation on a 100MW generator

Zone	Locational Tariff (£/kW)	Locational Charge (£000's)	Total Charge (£000's)	Total Commoditised charge by LF (£000's)		
				100%	65%	30%
N Scotland	18.15	1,815	2,226	2,660	2,365	2,069
S Scotland	9.41	941	1,352	1,787	1,491	1,195
NE England	5.84	584	995	1,429	1,134	838
Midlands	-1.79	-179	232	666	370	74
S Wales	-6.58	-658	-247	187	-109	-405
Peninsula	-12.63	-1,263	-853	-418	-714	-1,010

Based on 2008/9 charging data, where the residual generation tariff for generation is ~£4.11/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 ~50 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 ~50 percent. 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. This is illustrated in Figure 2, again using a 100MW generator as an example.

Figure 2 Impact of commoditisation on the residual charge of a 100MW generator

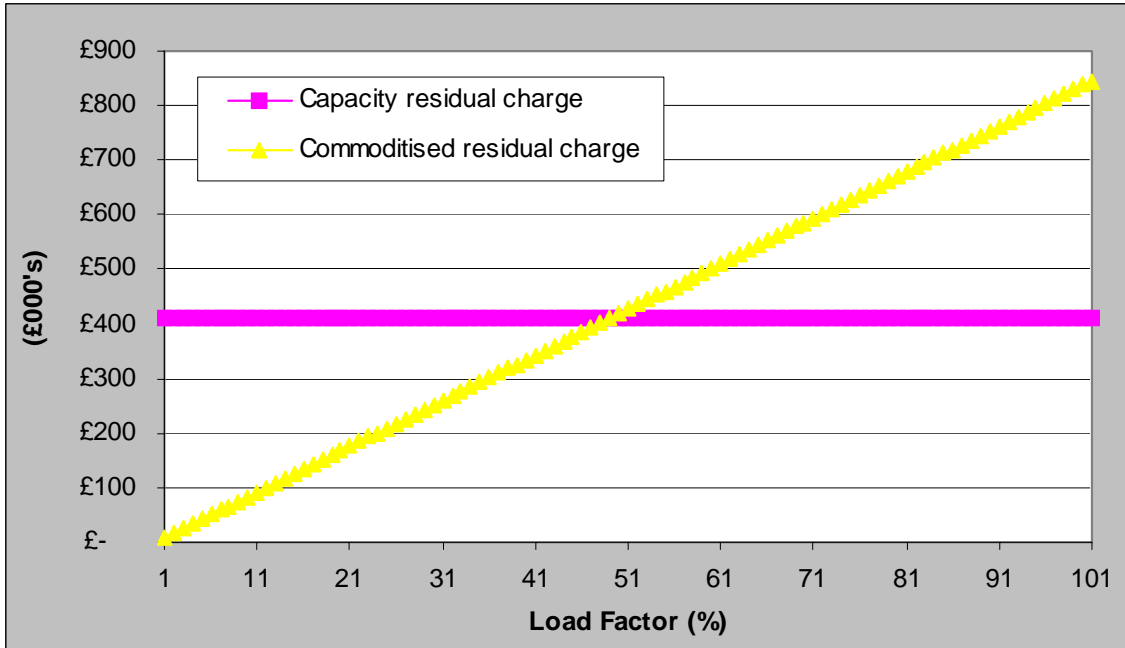


Table 3 identifies the basis upon which each of the elements of the TNUoS tariffs would be calculated and levied on Users of the GB transmission system with this option.

Table 3 Basis for calculating TNUoS tariffs

	Generation	Demand
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)*	Triad peak demand (MW)

* Annual metered energy output of a generator (MWh)

4.1.1 Calculation of monthly residual TNUoS generation charges

In the event that the option of commoditisation was to be implemented, there are a number of ways in which the resultant residual TNUoS generation charge for a User could be calculated on a monthly basis. This Section presents three options which were discussed by the Working Group and invites comment from the industry on each.

1. Calculation of monthly residual charge based on User forecast

It might be appropriate that a process similar to that of the calculation and levying of non-half hourly (NHH) demand charges is used to determine residual generation charges for Users on a monthly basis.

This would require generation Users to forecast metered energy to be delivered onto the GB transmission system over the financial year for each BM Unit. Industry views are welcome on whether it would be most appropriate for generation forecasts to be

provided by a generator on a half-hourly / daily / weekly / monthly or annual basis. Users annual residual generation charges would then be based on these forecasts, multiplied by the relevant residual generation tariff (£/MWh) and split evenly over the 12 months of the year.

Users would have the opportunity to vary their generation forecasts throughout the 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 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.

Residual generation charges would be reconciled 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.

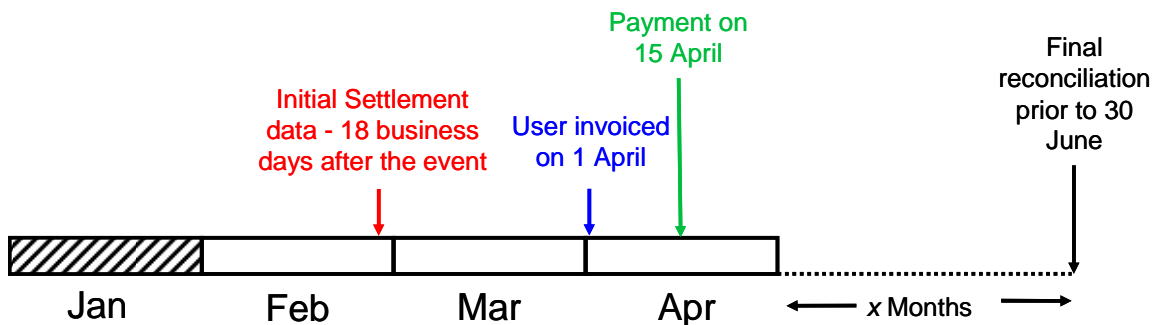
2. Calculation of monthly residual charge based on actual metered data

It might be appropriate that a process similar to that of the calculation and levying of Balancing Services Use of System (BSUoS) charges is used to determine monthly residual generation charges for Users. 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 3 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 1 April, with subsequent payment required on 15 April. Final reconciliation would then take place prior to 30 June in the following charging year.

Figure 3 Monthly residual charge based on actual metered data



3. Calculation of monthly residual charge based on historic load performance

The Working Group considered briefly, the use of historic generator performance as the basis for determining a monthly residual generation charge. This was considered inappropriate by the Working Group however, on the basis that a generators' historical performance might not be a suitable guide as to how that generator will continue to operate in the future. The return to service of a generating plant which had previously been mothballed was considered a good example of this.

4.2 Local Capacity Nomination

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.

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 £315m and an LCN charging base of 77GW (assuming the total GB TEC of 2008/9 as a proxy for determining this), the residual TNUoS generation tariff based on this option would be ~£4.09kW.

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
Locational	Long-term capacity booking (levied on Triad metered generation for generators in negative tariff zones)	Triad peak demand (MW)
Residual	LCN	Triad peak demand (MW)

4.2.1 Calculation of monthly residual TNUoS generation charges

In the event that the option of charging for the residual element of the TNUoS generation tariff were to be implemented based on LCN, the monthly charge would be one twelfth of the annual residual generation liability of a generator, calculated simply as the residual generation tariff multiplied by the LCN of that generator.

4.3 Daily Peak Generation

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 2008/9 revenues, assuming a daily peak annual generation charging base of 46TWh, a commoditised residual tariff for generation would be in the order of £6.85/MWh assuming that the existing 27/73 G/D split is maintained (£315m / 46TWh = £6.85/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
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)

4.3.1 Calculation of monthly residual TNUoS generation charges

The Working Group believed that each of the options considered for commoditisation in Section 4.1, were equally applicable (or not, in the case of the use of historical data) in the event that a daily peak generation charge were implemented.

4.4 Other options considered

Of the options discussed by the Working Group, each of the three presented above were considered to better meet the relevant Licence objectives than any of the other options considered. For completeness and to inform the debate at this pre-consultation stage, the following charging options were also considered and discounted as suitable by the Working Group:

Charge on Transmission Entry Capacity

Consideration was given to maintaining the existing charging arrangements by continuing to calculate and levy the residual TNUoS generation tariff on TEC. This was discounted however, on the grounds that the Working Group agreed unanimously that Users of short-term access products should be liable for the residual element of the TNUoS generation tariff. The calculation and levying of the tariff on TEC would not facilitate this and the option was therefore discounted by the Working Group.

Charge on Connection Entry Capacity

Consideration was given to calculating and levying the residual element of the TNUoS generation tariff based on a Users CEC, meaning that all Users connected to the transmission system would be liable for the tariff. It was noted that depending on which of the CUSC Amendment Proposals were implemented successfully, there was a possibility that a User could not be guaranteed any form of long or short-term transmission access, whilst remaining liable for the tariff. Additionally, it was considered that the use of CEC as a charging basis was not sufficiently flexible in that a generator with a CEC may not intend to generate within a charging year but

under such a regime, would be charged the residual element of TNUoS. This option was therefore discounted by the Working Group on the grounds that this would not be cost-reflective nor facilitate competition.

Charge on pro-rated TEC

Consideration was given to the calculation and levying of the residual TNUoS generation tariff based on the level of pro-rated TEC held by a generator in any charging year. Those generators with long-term access would be charged based on their TEC (or long-term access holding if this is no longer TEC). Those generators with short-term access products would be charged based on their level short-term access holding pro-rated to reflect the period of access held within that relevant charging year as a ratio of $X / 8760$ hours, where X equals the level of short-term access (MW) multiplied by the period (hours) for which that access is held.

It was noted, that in the case of the implementation of entry overrun (CAP162) it is implicit that a generator will operate in excess of its transmission access holding. Indeed, a generator may not hold any form of access product, but choose to overrun onto the transmission system. Working on the previously stated Working Group assumption that all generation should be liable for the residual element of the generation tariff, there would be a requirement to charge Users for entry overrun.

A number of potential solutions were considered as to how this could be dealt with, all of which required different charging arrangements to those based on pro-rated TEC. When assessed against the relevant charging objectives, this option was ruled out by the Working Group on the grounds that the calculation of separate residual generation tariffs for different access products might not be sufficiently simple and transparent to facilitate competition, whilst it was also noted that having two separate residual tariffs which effectively recover the costs of the same assets might not be considered to be cost-reflective.

Charge on maximum generation

Consideration was given briefly to calculating and levying the residual generation tariff based on a generators maximum generation over various timeframes i.e. daily, weekly, monthly, or annually. It was considered that the inherent uncertainty in the calculation of the tariffs might not necessarily facilitate competition and this option was therefore not given further consideration by the Working Group.

4.5 Assessment against the relevant charging objectives

As noted previously in Section 2 of this pre-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;

- 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.

All of the options for the calculation and levying of the residual TNUoS generation tariff considered by the Working Group were assessed against these objectives as follows:

Table 6 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	✓	✓
Charge on LCN	✓	✓	✓	✓	N/A	✓	✓
Daily Peak Generation	✓	✓	✓	✓	N/A	✓	✓
Charge on TEC	✓	✓	✓	✗	N/A	✓	✗
Charge on CEC	✓	✓	✓	✗	N/A	✓	✗
Charge on Pro-rated TEC	✗	✗	✗	✓	N/A	✓	✓
Maximum Generation	✗	✗	✗	✓	N/A	✓	✓

A more detailed assessment of the three preferred options by the Working Group against the relevant charging objectives is included in Section 5.

5 Views of the Working Group

The Working Group was very much split as to whether it should be considered most appropriate to levy the residual element of the TNUoS generation tariff on a half-hourly utilisation basis (either throughout the entire charging year or on a daily system peak basis), or to continue to calculate and levy the tariff on a capacity basis, for which a newly-defined Local Capacity Nomination was considered the most appropriate option.

For clarification, it is the intention that the locational element of the TNUoS tariffs 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. The Working Group considered that this continues to be appropriate on the basis that transmission investment is driven by the capacity of a generator applying to connect to the transmission system, not load factor.

Facilitating competition

The Working Group believed that there is a strong argument that the calculation and levying of the residual element of the TNUoS generation tariff based on actual utilisation (either throughout the relevant charging year or on a daily system peak basis) facilitates competition in that the calculation of tariffs is transparent, predictable and will be relatively stable given that allowed revenue is known and this would be divided by either annual or daily peak energy usage (taking into account

transmission losses for generation) which varies little year-on-year and is easily predictable.

The Working Group also considered however, that there was perhaps an equally strong argument that the calculation and levying of the tariff based on a pre-notified LCN facilitates competition in that again, the calculation of tariffs is transparent, predictable and will be relatively stable, dependent on allowed revenue and variations in the aggregated LCN year-on-year.

Assessed against the relevant Licence objective of facilitating competition, the Working Group considered that each of the three options presented in this pre-consultation better meet this objective equally.

Cost-reflectivity

In assessing as to which of the options presents the most cost-reflective solution, the argument essentially boiled down as 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 case for this is becoming less so, in which case a charge based on utilisation of the transmission system should be considered more cost-reflective. The Working Group was split in considering which approach represents the most cost-reflective solution. Opinions varied strongly, and there was both support and opposition for all three.

It was considered by some Working Group members that given that the GB transmission system is increasingly becoming a network with higher levels of plant capacity margin, and given that the TAR proposes increased 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), the use of total winter peak capacity booked as a proxy for transmission investment may be becoming less valid. It was therefore argued that investment in the transmission system is no longer solely incurred to meet winter peak demand, but for the entire year.

On this basis, the recommended options were those based on utilisation either throughout the entire charging year or on daily system peak. Of the two, it was considered by some Working Group members that the option of a daily system peak charge maintained a balance between recovering costs on both a peak and utilisation basis.

Alternative views within the Working Group were expressed on the basis that there may be no difference in the level of transmission investment required to accommodate two 500MW power stations with different load factors. In this instance, it was argued that the same proportion of the residual generation tariff should be applied to both power stations of varying load factor. On this basis, the levying of the residual tariff on a LCN basis was considered the most cost-reflective solution.

It was noted that the reasoning behind the implementation of the ICRP methodology introduced by National Grid in 1993/4 was that transmission assets are built to ensure that peak demand can be met by generators, and that the assets required to transport energy away from a generator is clearly related to a station's capacity. It was considered by some, that justification for moving away from this principle had not yet been made. One Working Group member considered that whilst there is no expectation for the basis of system design and planning to be changed in the GB Security and Quality of Supply Standard (SQSS), it is not clear that the use of capacity as the basis for investment is becoming less valid.

Additionally, it was also noted that a residual tariff levied based on utilisation would be detrimental to plant with a load factor of greater than ~50% whilst the residual revenue recovery relates to the existing installed transmission assets which were built to accommodate generation capacity. It was considered by some that charging generators on a kWh basis would potentially result in base-load generators cross-subsidising peak generators on the costs of operating a system built to meet peak demand.

Consideration was also given however, as to how cost-reflective it might be to charge a generator the residual element of the TNUoS generation tariff based on LCN in the event that a User could not be guaranteed any form of access to the transmission system, which ultimately depends on which of the proposed access products are implemented. Additionally, it was considered that there may be instances when the level of transmission investment required to accommodate two power stations of the same capacity is different, to meet SQSS standards for the relevant plant type (i.e. wind).

Developments in the transmission business

Given that each of the options presented have been developed as a result of the current TAR, all three options were considered to be 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.

6 Responses

Comments and views are invited on all of the issues raised in this pre-consultation document. To ensure that your comments and views are considered as part of National Grid's forthcoming consultation document, responses must be received by close of business on **Thursday 4th December, 2008**.

Comments are particularly welcome regarding:

- Whether Users of short-term access products should be liable for an element of the residual element of the TNUoS generation tariff to reflect their usage of the GB transmission system.
- Whether maintaining the existing 27/73 G/D revenue split is considered appropriate.
- The options considered by the Working Group presented in Section 4, and any potentially suitable alternatives which have not yet been considered.
- The options presented by the Working Group for determining a monthly residual generation charge, and any potentially suitable alternatives which have not yet been considered.
- The views of the industry on whether it is considered most appropriate to recover the costs of historic, lumpy investment in both locational and non-locational transmission assets on a capacity or utilisation basis.

If you wish to provide comments on this pre-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 Working Group Consultation* which is available on the National Grid website: <http://www.nationalgrid.com/NR/ronlyres/90D436DD-CDA8-4007-96D9-E8E4A03A28F8/28707/Cap163WGRReportv10.pdf>

Local Only Connections

5.62 The arrangements for local connections were developed by working group 3, and the conclusions are described below.

Definition of Local Capacity Nomination

5.63 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 the local transmission assets.

Summary of the properties of Local Capacity Nomination

5.64 LCN access 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 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.

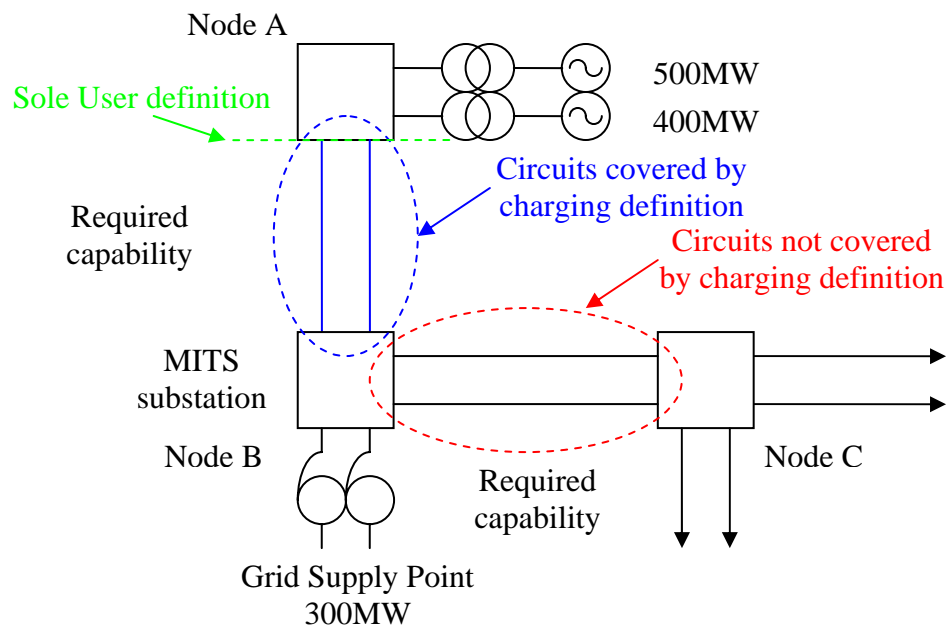
Enduring arrangements for existing LCN holders

5.65 Working Group 3 has debated whether LCN should be a finite right, linked (or not) to the period to 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 does not seem appropriate to link LCN to capacity obtained through the auction.

- 5.66 Working Group 3 considered that evergreen rights would be appropriate provided the definition of local assets is 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.
- 5.67 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 that 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.
- 5.68 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



- 5.69 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 circuits connected. In the diagram above, these are the circuits highlighted in blue.
- 5.70 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.
- 5.71 The Working Group agreed that different charging and CUSC definitions of “local” works would be required to:
- Avoid circumstances in which there would be a permanent output restriction on generators being connected; and
 - Protect individual generators from the actions of other or the decisions of the Transmission Owners.
- 5.72 The Working Group has not fully explored the consequences of two separate definitions of local works. However, the Working Group noted that having separate definitions was consistent with the way in which current Construction Agreements list the incremental works required to accommodate generators with the generator paying the Long-Run Marginal Cost (LRMC) derived from the Investment Cost Related Price (ICRP) transport and tariff model.
- 5.73 Given the proposed definition of local works, it was therefore considered appropriate to make LCN a finite right, whereby a generator would be required to notify National Grid of both its required LCN capacity and the period of time for which this was required. This was considered to provide a clear signal to the TO as to whether (i) ageing assets should be replaced or not; and (ii) the local capacity is available to be allocated to others.
- 5.74 It was acknowledged that since there could be circumstances in which multiple Users wished 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.

Application processes

- 5.75 **New connections:** Existing applications for a 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 (namely CAPs 161, 162, 163, 164, 165 and 166), it is foreseeable that a generator may wish to obtain only short-term access

products following connection. Given that a generators Local Capacity Nomination 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.

- 5.76 **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.
- 5.77 **Application fees:** Given the proposed changes to the transmission access regime, it is considered appropriate 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.
- 5.78 **Pre-commissioning user commitment:** Working Group 3 identified that, where LCN is allocated over a finite period, 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.
- 5.79 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.
- 5.80 The CAP165 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 8 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.
- 5.81 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:

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

- 5.82 If the 50% risk sharing, consistent with the CAP165 treatment for wider access is applied, the result is a multiplier of 8.
- 5.83 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.
- 5.84 The Working Group therefore concluded that, consistent with the CAP165 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.
- 5.85 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.
- 5.86 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:

$$\text{Local Capacity Reduction Charge} = \text{LCNr} \times \text{LCAMt}$$

Where:

- *LCNr* is the reduction in Local Capacity Nomination in kW.
- *LCAMt* 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) $\text{LCAM} = \text{LTA} \times 100\%$, where LTA is the Local Termination Amount;
 - Where $t=-1$, $\text{LCAM} = \text{LTA} \times 75\%$;
 - Where $t=-2$, $\text{LCAM} = \text{LTA} \times 50\%$; and
 - Where $t=-3$, $\text{LCAM} = \text{LTA} \times 25\%$.

$$\text{Local Termination Amount} = \text{Max}(0, (\text{LocGenTNUoS}_n \times X))$$

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

- 5.88 **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.
- 5.89 It is therefore necessary 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.
- 5.90 **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 financial year, with the notified decrease in TEC taking effect on 1 April of that same year. When discussing the possibility that LCN could be evergreen, the Working Group considered that this process could be applied to LCN. (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 23 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.
- 5.91 However, given that the Working Group concluded that LCN should be a finite right, it would not be necessary to adapt the existing process for decreasing TEC for LCN. Instead, having applied for and obtained an LCN for a finite period, a User would be committed for this period, with an obligation to pay a Local Capacity Reduction Charge in the event of termination or reduction of LCN.
- 5.92 **Post-commissioning user commitment:** Consistent with the proposed arrangements for wider access, treating local connections through finite rights would require Users to nominate for how many years they would require the use of such a local connection. When the provision of such rights requires transmission works, a minimum booking period, equal to the multiplier used to derive the Local Termination Amount (initially eight years), will apply.
- 5.93 Users would be liable for all (local generation TNUoS) charges associated with the full period of their booking. A User that wished to terminate or reduce its LCN during the period of the booking would be required to pay a fee, as follows:

$$\text{Local Capacity Reduction Charge} = \text{LCNr} \times \text{LocGenTNUoS}n \times n$$

Where:

- *LCNr* is the reduction in Local Capacity Nomination in kW.
- *LocGenTNUoS* is the relevant prevailing nodal Local Generation TNUoS tariff.
- *n* is the number of years of the booking remaining.

- 5.94 **Post-commissioning security:** Financial security would be required for the balance of the current year's local generation TNUoS charges. This amount would be added to each User's Security Requirement, as defined in paragraph 3.22 of the CUSC, and, to the extent 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.

Transitional arrangements to LCN

- 5.95 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 generator's 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 notification 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.

Local/Wider Interaction

- 5.96 Working Group 2 discussed circumstances in which interactions exist between the local works required to give a number of users access to the transmission system. The proposed approach of allocating local capacity on a first-come, first-served basis is simple and has the advantage of making the auction for wider transmission access more straightforward and transparent. The disadvantage with this approach is the inconsistency with the proposed approach for allocating wider transmission access and the risk that capacity does not go to parties that value it most due to the timing of applications for local capacity.

- 5.97 The working group discussed the alternative approach of including all local capacity constraints in the auction for wider capacity. Whilst this would resolve the disadvantages described above, it would make the auction for wider transmission access more complex and consequentially less transparent for users. This approach would also make it difficult for users to hold different levels of local and wider transmission access. This would be a problem for users that may wish to use an efficient combination of long-term and short-term access rights.