

## GB Transmission Charging Methodologies Forum

### Draft Meeting Report: 29 April 2008

*This report outlines the key discussions and actions of the GB TCMF meeting. All presentations, agendas, meeting notes and future meeting dates are available at the TCMF web page of the National Grid Industry Information website at <http://www.nationalgrid.com/uk/Electricity/Charges/TCMF>*

---

#### ATTENDEES

Chris Bennett	National Grid (Chair)	Nigel Fox	National Grid
Hêdd Roberts	National Grid	Andrew Truswell	National Grid
Patrick Hynes	National Grid	Tom Ireland	National Grid
Andrew Rimmer	First Hydro	Paul Jones	E.ON
Will Kirk-Wilson	National Grid	Robert Longden	Airtricity
Chris Barrass	Centrica	Anthony Mungall	Ofgem
Michael Wilks	KEMA	James Anderson	ScottishPower
Andrew Manning	N Power	Peter Waghorn	Cornwall Energy
Louise Schmitz	British Energy	Craig Maloney	National Grid
Richard Ford	Renewables Energy Systems Ltd	Sarah Hall	National Grid

---

#### 1 Actions from previous meeting

**Action:** The meeting agreed the Minutes and Actions, these can be located on the website at <http://www.nationalgrid.com/uk/Electricity/Charges/TCMF>.

**Action on National Grid to provide clarification concerning the proposed charging arrangements for CEC before TEC applications** - included in verbal update by Nigel Fox covered below.

All presentations have been placed on the Industry website.

#### 2 Current Charging Issues

- **Transmission Access Review**

**Short Term – Patrick Hynes**

- **CAP161 SO release of short-term rights** – PH ran through the key features and charging issues associated with the CUSC amendment such as reliance on the definition and charging of a 'local only' connection. There is a consequence on BSUoS cash flows e.g. could increase. Questions that must be answered include: How does the auction revenue feed into BSUoS? And will revenue from such a release skew the 27:73% split of revenue?

Detailed design of auction process will be determined by the Working Group. The initial assumption is that it is pay as bid, so other than the interaction with local and residual there is limited impact on charging methodologies. However, it was noted that there was concern over long term and short term revenue interaction.

- **CAP162 Entry Overrun** – A generator will be able to export as soon as a local connection is achieved i.e. TEC isn't required. The User will be exposed to the cost of overrun. All subject to a local capacity limit. There are credit implications; units using overrun products are far more dynamic than those currently with TEC, so do the credit arrangements need to change? Settlement is assumed to be on a zonal basis.

Issues include: Local asset charging; how to price the overrun; how will the overrun revenue interact with BSUoS revenues; will the 27/73% revenue split need to be kept; can you have a negative overrun charge or do we cap this at zero.

3 basic models have been identified for overrun pricing: a simple multiplier (x TNUoS or BSUoS); Cost recovery (semi automatic degut); or a marginal cost model. These models will be developed and discussed in the WG.

- **CAP163 Entry Capacity Sharing** – Shared access within a zone between Users. Users would need a local connection and zones may need to be more stable over time.

The working group will determine the requirement and format of notification of sharing. Again any impact on the charging of the residual will need to be considered. Sharing access rights will also impact on constraints, being more expensive as the zones get larger.

- **CAP164 Connect and manage** – Essentially, this is Overrun but with costs socialised. A fixed connection date the later of local transmission works or a fixed lead time. Consumers, rather than the connectee, take on wider reinforcements risks. If a connectee requests a fixed date charges will apply from that date. It would be charged as TEC/ TNUoS (i.e. asset based charge). Operational costs would be expected to increase. The Working Group will seek to perform a cost benefit, including the cost of carbon savings.

### Long Term – Andrew Truswell

- **CAP165 Finite long term entry rights** – Users would nominate the number of whole years of firm access rights they require. After this period the capacity can be released to other Users. It is anticipated that some level of financial security will be required for this long term commitment. Long term rights could be increased by application. Incremental capacity would be triggered by booking number of years and providing associated commitment from the User. A local connection would allow short term products to be used if no long term rights were purchased. Charging issues are: should the TNUoS tariff have increased certainty too - fixed tariffs or index linked; should long term modelling / forecasting be used in setting fixed tariffs ; what would then happen for over or under recovery? The assumption is that local charges are split out.

Comments were:

PJ – if you fix locational tariffs, the residual (variable) element will just take the slack and therefore users will be still subject to the same charge uncertainty and movement. The status quo should be considered too e.g. charges are dynamic and will change each year.

RF – If more users apply for access in a future year, is firm access awarded above the expected capacity of the network? Or is there a limit? i.e. who takes planning risk? Can you book a year off e.g. access for the next two years, then a year off for refurbishment then a further block of firm access?

- **CAP166 Entry Capacity Auctions** – Access rights are auctioned up to the baseline, going to the highest bidder. The access rights would be zonal based, released in annual

blocks. There would be an associated User Commitment. Incremental capacity would be released when a regulatory test has been met.

A pay as bid auction is envisaged. It is anticipated zonal reserve prices are needed and based on wider locational element of existing TNUoS. Are negative reserve prices workable? Will it only be limited to those physically connected? How do you prove negative prices i.e. the existing triad type arrangements may not be enough. Are step prices for incremental capacity needed, as with Gas? Over recovery expected as capacity in some zones is currently constrained. Anticipated it would be settled through the residual. Extreme over recovery may have additional issues.

RF – what about future connections, can they bid for access without a current physical connection?

AT – Maybe it could be a firm connection offer rather than a commission physical connection. Working Group will look at how far forward a potential project can 'bid'.

PJ – Is reserve prices part of methodology or code? Methodology within gas.

### Supporting Changes – Craig Maloney

- **Zoning criteria** – New zoning methodology required for 5 of the 6 CAPs to replace existing. Not limited to just transmission charging so a new zoning methodology (stand alone) could be developed.

CB – how far away are we from developing this? HR - Have draft zones but need to test robustness against potential future network changes i.e. you could assume the physical network capability of today but this will change. The other option is to ignore physical network capacity and use incremental changes of flow. National Grid appreciates that zones are very much needed to develop the other CAPs.

- **Local asset charging** – Need to charge local infrastructure separately to wider infrastructure to facilitate appropriate charging for short and long term products. GBECM 11 preconsultation published in March. Three high level options. Specific charging, distance to zonal hub and deepening of charging boundary. Requires a definition of local works/ assets, which could sit in the CUSC or Charging Methodology.

BL – what were the preconsultation responses like? Are you closer to narrowing down?  
TI – no support for a deeper connection boundary and some support for the other two but more fundamental and detailed analysis of distance to zonal hub is needed to 'convince' respondents.

PJ – definition could go in CM but as it's a precondition for some short term assets could it go into CUSC?

- **Commoditisation of residual** – Ensures the correct total revenue recovery, includes costs of substation assets. Both users of long and short-term products should fund residual. NG must charge on a cost reflective basis. This could be achieved by charging on a commoditised basis e.g. £/kW. 27% will still be recovered from Gen and there is an interaction with revenue flows.

MW - 27% G revenue split - wouldn't it be simplified if we didn't try to hit this fixed value. Is this truly a requirement? NG –could be changed but we have to be mindful of wider obligations. E.g. European tariffication guidelines .

The appropriate arrangements to ensure consistency between the three groups was discussed. The enabling group will come up with work that will feed into the other groups and therefore it is only really two groups that have to ensure congruence. Each

individual CAP must be assessed against the Relevant Objectives on a stand alone basis, and all work in isolation. Can this approach allow a selective picking of just a couple of products or do they all need to be sanctioned for it to work. PJ – it is possible that we will conclude that the individual CAP should still better meet objectives marginally without the other

- **Embedded Generation**

Licence Condition C13 (small generators discount) effectively ceases at the end of the 2008/9 charging year. National Grid will shortly publish a discussion paper exploring two longer-term enduring solutions to the wider issues associated with embedded generation, whilst considering what might be a possible interim solution to the issue of cost-reflectivity in transmission charges between those generators connected to the transmission system and embedded generation in the form of a modification to the TNUoS charging methodology.

In addition, National Grid is proposing to raise a modification to the CUSC in May 2008, regarding the current thresholds associated with CAP097. The aim of the modification will be to increase the level of transparency to the GBSO of generation connection to the distribution networks.

PJ – Gross or net, supplier or DNO. Isn't there another option of Gross DNO? If it isn't gross you might as well keep up the existing relationship with the supplier? HR - When NG consults on competing models, this will be the opportunity for someone to raise it.

- **Update on Offshore Transmission Charging**

The Offshore Charging regime is being progressed through the existing charging governance mechanism. NG is preparing a fully robust methodology. Two areas of further, outstanding work include developing the detail of how locational and non-locational costs will be split. This could potentially be through the tender process or through an obligation in the STC. Secondly, the GB ECM-08 consultation did not explicitly address part year connections. There could be an issue at transition and for future connections that do not connect on 1<sup>st</sup> April. Another interaction is with GBECM-11 Local Charging and how to charge the specific security factor that is expected with the zero redundancy offshore regime. Don't need an agreed methodology until December 2009 but recognise that giving certainty to the industry will also be very important. We're currently considering how to do this – one possibility would be a "minded-to" paper to give visibility without committing to final CM drafting.

Ofgem also confirmed that their forthcoming paper will be a further focusing of policy and may contain some draft text.

Offshore embedded transmission – PJ presented a model showing that embedded transmission networks could be charged to generators as a connection charge, and that such generators would essentially remain embedded for all other purposes i.e. embedded benefits. It was questioned whether this may result in radically different charges between embedded transmission connections and other offshore transmission connections. PJ's response was that OTETWG concluded that the generator would essentially be able to choose the type of connection it wanted.

- **CEC before TEC connections**

NG have written to Ofgem to explain next steps, and this will be published on the NG website shortly.

**3 Events before Next Meeting**

Working Group timetable and members to be published this week. Mainly in Warwick and London. 12th May is the first one (WG3), in AEP offices. 13th and 14th are working groups 1 and 2.

**4 Any Other Business**

- **Date of Next Meeting:**

The next TCMF meeting is to commence at 10am on 18<sup>th</sup> June at National Grid House Warwick

The CISG meetings are to be cancelled throughout the Transmission Access Review in order to allow Industry member to attend the various Working Groups sessions.

**End of Report**