## Meeting report

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| **Meeting name** | Transmission Charging Methodologies Forum |
| **Date of meeting** | 12th March 2015 |
| **Time** | 11:00am – 15:00 |
| **Location** | National Grid House, Warwick |

## Attendees

| Name | Initials | Company |
|---|---|---|
| Patrick Hynes | PH | National Grid (Chair) |
| Juliette Richards | JR | National Grid (Technical Secretary) |
| Dave Corby | DC | National Grid (Presenter) |
| Stuart Boyle | SB | National Grid (Presenter) |
| Wayne Mullins | WM | National Grid (Presenter) |
| Nick Pittarello | NP | National Grid (Presenter) |
| Duncan Farthing | DF | Xeroenergy |
| James Anderson | JA | Scottish Power |
| Christoph Horbelt | CH | Dong Energy |
| Joseph Underwood | JU | Drax |
| Nick Kay | NK | Verbeia Energy |
| Richard Mawdsley | RM | Haven Power |
| Paul Brennan | PB | Waters Wye |
| Herdial Dosanjh | HD | Npower |
| Aled Moses | AJ | OFGEM |

## Dial In

| Name | Initials | Company |
|---|---|---|
| Fruzsina Kemenes | FK | RWE |
| Simon Holden | SH | LR Senergy |
| John Tindal | JT | SSE |

All presentations and supporting papers given at the TCMF meeting can be found at:
http://www2.nationalgrid.com/uk/Industry-information/System-charges/Electricity-transmission/Methodology-forum/

## 1 Ongoing modification proposals – Juliette Richards

1. Ongoing CUSC modification proposals and strategic issues were presented with updates for each, as per slides 5 to 10.
2. A question was raised with regard to CMP213 – has there been any further progress on the judicial review? PH noted that interested parties have submitted evidence and the next stage in the process will be a hearing date, which has not yet been announced.

## 2 Implementing potential changes to the G:D split – Stuart Boyle

3. SB presented slides to look at the potential impact of removing the 2.5 Euro / Megawatt cap on generation charges.
4. The impact of the cap removal was modelled to show tariff impacts for both demand and generation. One attendee asked why the impact on generation and demand differs – SB explained that this was due to the different sizes of the charging bases for generation and demand.
5. One attendee asked whether there has been any active progress from the EU at this stage to remove the cap. SM explained that ACER put forward an opinion that the cap should be removed, but there has been no progress at the European level towards implementing this, and hence this represents an area of uncertainty for industry - and represents a risk given that there could be a large impact on charges.
6. GP noted that the change in EU commissioners may be partly responsible. Whilst there have been high level talks with regards to the Energy Union and tariff harmonisation, the scope of this has not been clear. NP also noted that the current ACER questionnaire focusses more on tariff *structures* rather than tariff *levels*.
7. SB asked attendees whether a contingency plan is needed at this stage to prepare for any change or removal of the cap. Attendees discussed and concluded that it is probably too early to prepare this – the outcome of CMP227 needs to be decided first, and there are other uncertainties at the European level. It was therefore decided to leave this area as a 'watching brief' for now – awaiting the outcome of CMP227 and any further EU activity.

## 3 BSUoS stability – Nick Pittarello

8. NP introduced the topic of BSUoS stability. Since talks with industry last year, the definition of BSUoS stability has been further refined, with clearer scoping of issues.
9. NP talked through the different components of BSUoS charges (energy imbalance and SO actions) and gave 3 examples that resulted in differing BSUoS charges, and their interaction with Residual Cashflow Reallocation Cashflow (RCRC). The *Problem Definition* slide was considered by attendees, with NP asking for feedback as to whether these areas have been correctly defined / scoped. One attendee asked whether a single cash out price would change these problem definitions – after some discussion attendees concluded that although this could reduce RCRC it would not change the problem definitions fundamentally. TCMF agreed that the problem definition as scoped was accurate.
10. A further point of discussion was raised with regard to whether energy imbalance and constraints should be treated separately rather than within one charge. Could there be any way of separating these and looking at the problems afresh – particularly the geographical aspect of constraints? PH noted that this touches upon some long running discussions linked to locational BSUoS. However implementing locational BSUoS would mean that the methodology for TNUoS would also need to be reviewed, as TNUoS allows firm access to the transmission system and already includes a locational element. Introducing locational BSUoS on top of locational

TNUoS would lead to an element of double charging for the same issue. JA also noted that locational BSUoS would also represent a price signal that is difficult to respond to *ex post.*

11. NP then introduced slide 23, looking at possible solutions to fix the BSUoS price using a BSUoS stability fund. National Grid noted that it would not be possible for the SO to shoulder the possible exposure for the whole industry. GP noted that he would not immediately discount the idea that the cash flow risk to the System Operator would be unmanageable. He noted that the SO is probably the best placed in the industry to assess the costs of constraints across the year. There is already an incentive on the SO to forecast BSUoS charges accurately. If this forecast could be made sharper, the difference between a forecast fixed price and actual prices could be minimised. Or in a fund scenario, the size of the fund would also be influenced by the accuracy of forecasting and the setting of the fixed price according to this.
12. One attendee asked whether imbalance or constraint costs are the bigger factor in driving BSUoS? NP answered that the primary causes are high wind levels and outage plans go on for longer than anticipated.
13. National Grid noted that a recent report has mentioned the idea of an *ex ante* BSUoS price. With regards to the SO being well placed to know constraint costs, PH also noted that some events are not within National Grid's control. For example the SO could be anticipating certain power station closures within a year and if this did not take place, high constraint costs could ensue. So there is inherent uncertainty.
14. Another attendee asked about the possibility of running a BSUoS stability fund over 2 years rather than one. NP responded that this would require an even bigger buffer within the fund – so there is a trade-off here. Another suggestion put forward by an attendee was that of collecting a BSUoS stability fund over a staged period. NP noted that this is the kind of detail that could be picked up in a work group.
15. The group then considered slides 25 and 26. The potential size of the fund was discussed, National Grid noted that the SO side of NGET (which has a small asset base) would find it difficult to cover a fund requirement of £100m. An attendee noted that it may be the case that the industry could do this cheaper themselves – this is dependent on the differing costs of capital between NGET and industry. National Grid noted that there are other Transmission Owners also, potentially with lower costs of capital than industry – but was it right for the SO to use the TO asset base as collateral against which to borrow? Is it the role of National Grid to be a bank for the industry?
16. GP noted that a key area for industry is better forecasting of BSUoS – and that if the SO had to contribute to the stability fund, even if this was only a certain proportion of the fund, this could encourage better forecasting. PH noted however that this could encourage over forecasting. GP agreed but noted that consistent over recovery would lead to pressure from industry to re-distribute the fund and further improve forecasting.
17. JA also noted that there is the issue of parties entering and exiting the market – and potentially benefitting from inputs from previous parties. It was questioned whether parties would be able to 'claim back' the monies they had contributed to the stability fund and whether it would be legitimate for new entrants to pay more.
18. CH suggested considering changing settlement periods – whilst this wouldn't address the problems being discussed, it could lead to a smaller fund requirement, that would then be more manageable for the SO to cover. Attendees also noted that the larger the fund required, the more likely this was to provide a market entry barrier.
19. JA: How much credit cover is currently provided for BSUoS? NP was not sure but will find out and feed this back to the group. JA asked whether both credit and stability fund cover would be required if a fund was in place? PH noted that each of these would have different purposes – credit to cover risk of non-payment, and cash (in the

fund) to address the issue of payments being short of receipts in a fixed price scenario. PB asked how the flat charge would be allocated? NP noted it would still be based on energy volume per day (i.e. Megawatt hours) – but because the charge was now known in advance, it could impact day to day generator dispatch decisions. A work group would need to consider whether this could lead to any perverse or unanticipated behaviour.

20. CH also suggested whether there were other 3rd parties that could fulfil the role of the fund by providing cash cover or similar.

21. HD suggested doing some backwards analysis to see how a stability fund would have played out in the past few years – particularly during the period of greater volatility last year.

22. The group concluded that they would like to take the issues and suggestions from today away to be considered internally. Some attendees noted that whilst BSUoS stability is a key concern for their organisations, it has been felt to be too complicated to tackle, and hence the work done by NP was very much appreciated. It was noted that National Grid is not under time pressure to move anything forward in this area – it is important to get the analysis right as there are huge implications.

23. **Action**: All attendees agreed to take the BSUoS stability work and discussions from today's meeting back to their organisations to review internally – in preparation for an interactive session at the next TCMF. JR to send out just the BSUoS slides from today's discussion to the TCMF distribution list, so that attendees can share this internally.

## 4 Western Isles Anticipatory Investment – Juliette Richards

24. JR talked through slides 29 – 32 looking at a proposal for treatment of anticipatory investment in the local circuit charge for a project in the Western Isles.

25. JR explained that 9 responses had been received to the open letter published by National Grid in December, which asked for input on different options to calculate the local circuit charge. 7 respondents supported option 1 (50% of the overall cost of the 2 cables being used to calculate the local circuit charge) – this was the option put forward by Baringa at TCMF in September 2014.

26. Having considered the various responses, National Grid believes that option one is most consistent with the charging methodology, as this is most consistent with how oversizing on AC circuits is treated and would have the most favourable impact on charging stability also. Attendees were asked if they had any further thoughts or comments.

27. NK asked how quickly this charge would come into effect. PH confirmed that effectively this is how the local circuit charge would be treated immediately, with some guidelines published shortly to confirm. However if another CUSC party wanted to raise a modification to consider a different option for charging they are able to do so – but this would be subject to the usual modification timescales.

## 5 Implementation of P272 – Damian Clough

28. DC presented slides to give the background to a recent urgent modification that has been raised to look at the implementation of P272. When meters are transitioned from NHH to HH within year they will receive a NHH charge plus a HH charge resulting in the liability being greater than if they were only NHH or HH settled for the whole year.

29. Under the proposal being put forward for CMP 241, for the purposes of TNUoS demand charges all meters within Profile Classes 5-8 moving to Measurement

classes E-G post 1st April 2015 will be settled as NHH for the **whole** charging year up until the implementation of P272. This will avoid any customers being over charged.

30. The CUSC panel will be meeting on 13/03/15 to review the Workgroup report, followed by a Code Administrator consultation for 2 working days from 13/03/15. It was also noted that the BSC panel have decided to look at the possibility of delaying P272 for 12 months.

## 6 Charging for offshore Interlinks – Wayne Mullins

31. WM talked through the slides focussing on an issue highlighted by offshore developers to consider how an interlink (linking 2 offshore generators) would be charged for. This issue was first introduced at the January 2015 TCMF.
32. WM introduced 3 different scenarios (slides 41 – 43) which have been used to create a number of principles for interlink charging. The first was that where an interlink provides equal benefit to two generators, they should pay the same charge for the interlink. The second principle was that where an interlink provides a generator with additional redundancy via the links to shore, charges for this should be at an equivalent level to the charge offered for a double circuit radial link. The third principle was that generation should only be charged for their share of the proportion of interlink capacity they could potentially utilise. This is pertinent when the 2 generators that are linked together are not of equal size.
33. WM noted that there will need to be some clarification as to how generators at differing distances to the shore are charged. GP noted that distances are unlikely to be hugely difference, given that it would likely only be efficient to link projects together that are relatively close.
34. CH asked whether for case 2 on slide 42, the security factor would be 1.8 in this instance? WM confirmed that this would be the case if the projects were at equal distances to the shore.
35. DF asked about a scenario with 3 generators. WM said that if a principle can be established for 2 generators, this could be expanded for 3 generators by looking at the beginning and end points of each link – as long as all the power from these projects is connected to the same substation.
36. JA asked about a scenario where 1 cable was rated at a lower capacity than the other – WM confirmed that you would need to look at who was able to use the connection to shore at any one time.
37. WM confirmed that a CUSC modification proposal will be raised for the March panel in order to provide clarity on charging for interlinks.

## 7 Update on website – Dave Corby

38. DC introduced some brief slides looking at the current structure of the charging section of National Grid's website – including some feedback that has been received and some suggested improvements to the site structure. DC reminded the group that National Grid is keen to hear feedback on the website as it exists for the benefit of customers.
39. Attendees noted that the improvements to the structure would be welcome. CH noted that sometimes links don't work – e.g. on the Grid Code area when going from Grid Code mods and then back to the Grid Code area. **Action**: PH agreed to feed this back to the Grid Code team. Another attendee noted that the 'contact us' button usually takes you to a contact for gas. **Action**: DC to add a clearer contact option on the charging area of the website, to include his email address.

40. One attendee asked whether there was any possibility of having a consultation page that went across all Codes? This would be helpful to understand cross cutting impacts. JA noted that some maps can be difficult to find / read. CH also noted that it is not always easy to find the most up to date version of a document – PH noted that the structure of the website is to have most recent documents towards the top.

41. With regards to regular updates on CUSC modifications PH noted the monthly update report from the Code team. **Action**: DC to ask Code team regarding the subscription of the Panel summary circulation list to ensure TCMF attendees are included.

42. DC will feed back to TCMF when he has made improvements to the website.

## 8 Overview of priority issues – Dave Corby

43. DC presented a summary slide to illustrate priority areas that TCMF members have said they would like to consider. Attendees noted these were priority areas, however PH noted BSUoS forecasting transparency does not fall under the remit of the ECCD team so this will be fed back internally. PH also noted that for any area that attendees feel is a priority, they are welcome to bring discussion items or straw men to TCMF.

## 9 TCMF Terms of Reference – Juliette Richards

44. JR talked through the aims and objectives of TCMF as laid out in the current terms of reference.

45. It was agreed that PH would take away an action to re-draft the terms of reference to specifically include sections 2 (connections), 3 (use of), 6 (general conditions), 14 (charging methodology), 15 (user commitment) of the CUSC. Any change to the terms of reference will need to go to the CUSC panel.

46. Attendees also noted that to encourage attendance at TCMF a name change could be helpful – e.g. to the 'CUSC users forum' or similar. PH noted that the name was set in NGET's transmission licence, so any change would need to be OFGEM. **Action**: PH to speak to Catherine Williams at OFGEM.

## 10 AOB

**1.** Timings of future TCMF meetings were discussed. **It was agreed to keep the meeting beginning at 11am.**

## 11 Actions

The following actions are summarised from the text above:

I. **NP** to look at current credit cover provided under BSUoS and note this in the future discussion on BSUoS stability

II. **All attendees** agreed to take the BSUoS stability work and discussions from today's meeting back to their organisations to review internally – in preparation for an interactive session at the next TCMF.

III. **JR** to send out just the BSUoS slides from today's discussion to the TCMF distribution list, so that attendees can share this internally.

IV. **PH** to feed back comments about the Grid Code area of the website to the Grid Code team.

V. **DC** to add a clearer contact option on the charging area of the website, to include his email address.

VI. **DC** to ask Code team regarding the subscription of the Panel summary circulation list to ensure TCMF attendees are included.

VII. **PH** to re-draft terms of reference for TCMF to take to a future CUSC panel, and to speak to Catherine Williams at OFGEM regarding changing the name of TCMF.

## 11 Next meeting

**Next meeting: Wednesday 13th May**

**Time : 11am**

**Venue :** National Grid House Warwick