nationalgrid

Meeting report

Meeting name	Transmission Charging Methodologies Forum
Date of meeting	11th May 2016
Time	11:00 – 13:30
Location	National Grid House, Warwick

Attendees

Name	Initials	Company
Wayne Mullins	WM	National Grid (Chair)
Juliette Richards	JR	National Grid (TCMF Technical Secretary)
Damian Clough	DC	National Grid (Presenter)
Jo Zhou	JZ	National Grid (Presenter)
Graham Stein	GS	National Grid (Presenter)
John Brookes	JB	National Grid
Guy Phillips	GP	Eon
Lewis Elder	LE	RWE
Peter Bolitho	PB	Waters Wye
Joseph Underwood	JU	Drax Power
Aled Moses	AM	Dong Energy
Edda Dirks	ED	Ofgem
Garth Graham	GG	SSE
James Anderson	JA	Scottish Power
Kyle Maryon	KM	Haven Power
Claire Warren	CW	Haven Power
Kenny Stott	KS	SHE Transmission
Eamonn Bell	EB	Renewables UK
Ian Tanner	IT	UK Power Reserve
Kate Dooley	KD	Energy UK
Robert Longden	RL	Cornwall Energy
Jean-Philippe Marty	JPM	Smartest Energy
Paul Mott	PM	EDF (via dial in)
Marc Smeed	MS	Xero Energy (via dial in)
Matthew Holts	MH	Intergen (via dial in)
Simon Holden	SH	LRS Energy (via dial in)

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 Update on new and ongoing CUSC modification proposals (charging) – Juliette Richards

1. Ongoing and new CUSC modification proposals (charging) were presented with updates / information for each.

2 Discussion on potential CUSC modification to look at GAV calculation – Nigel McManus, Eneco – *via dial in*

2. NM was unable to join the meeting via dial in due to technical issues so attendees were asked to look at the slides and feed back comments to NM or JR.

3 Generation zones for TNUoS – Lewis Elder, RWE

3. LE introduced his slides, explaining that the marginal costs of additional power injection at each node (from the transport model) are taken and then the nodes grouped into zones where nodal marginal costs are within +/- £1 of each other for the purposes of TNUoS charging. This approach gave 27 generation zones at the start of the price control. The CUSC, section 14.28 explains that this approach dampens fluctuations in charging that would otherwise be observed, thereby enhancing the stability of tariffs.
4. LE noted that in the CUSC, zones are re-calculated only at the start of each price control and in ‘exceptional circumstances’. He also noted that applying the +/- £1 today would in fact give rise to 41 generation zones. Potentially the defect here is that the +/- £1 criterion in the CUSC is not inflation linked (whereas the expansion constant calculation is re-based by RPI each year).
5. There are various ways that this potential defect could be addressed, for example index-linking the criterion, agreeing an arbitrary number of zones or mirroring demand zones. LE presented some analysis to show that if the zones had been based on a +/-£1 criteria that was RPI linked since ICRP, this would result in 27 generation zones today. If the zones had been based on a +/-£1 criteria that was RPI linked since privatisation, this would result in 21 generation zones. An attendee noted that ‘privatisation’ took a number of years, it was noted that for the purposes of this analysis it was taken as 1990.
6. LE asked the group for feedback on whether they too feel this is a defect, whether they had comments on the potential solutions proposed and whether they felt this issue should be addressed now or in the next price control period.
7. Attendees noted that charging zones exist to incentivise behaviour as well as recover charges. Some felt RPI linking the zoning criteria might be the most obvious solution. A further attendee noted that any modification that goes forward should have as tight a defect as possible, as this issue touches on the cost reflectivity vs. stability debate. GG noted that even with 21 zones there were zones with only 1 or 2 generators in. This leads high volatility of prices in these zones when generators close or enter. JA noted that this issue may also be highlighted due to the fact that price controls are now longer.
8. A further attendee noted that any proposal to re-zone would need to take place with as much notice as possible, as there may be initial winners / losers. JA also noted that with 41 zones, prices begin to ‘look’ nodal in Scotland, plus the fact that with parts of the Tx network at lower voltage in Scotland this would already increase the number of zones (as the expansion constant for lower voltage lines is higher).
9. GG noted that it could be useful to look at how this works in Sweden, Ireland and Romania, the 3 EU countries that have locational signals. WM agreed but noted you would also need to look at the direction of travel in market arrangements within those

countries. Furthermore any solution would need to be broadly in line with the EU direction of travel on tariff harmonisation.

10. LE summarised that it sounded like this was an area TCMF attendees would like to look at but without a clear / consensus view on what the solution might be, and that it was important to keep the EU angle in consideration.
11. BL asked whether re-zoning would be raised at the next mid-period review? WM confirmed that presently, National Grid has no plans do so.

4 GC0079 (ROCOF setting) and impact on BSUoS – Graham Stein, National Grid

12. GS introduced his presentation, explaining that the GC0079 is a joint GCRP and DCRP workgroup considering loss of mains protection at stations of <5MW. The Workgroup is likely to recommend a mandatory change to protection settings similar to that recommended by GC0035 for stations of 5MW and above because the ensuing balancing cost savings are estimated to be greater than the cost of implementation.
13. GS explained that the Workgroup are considering 2 options to go into their report:
    i. **Option 1:** Work is undertaken and costs are borne by the parties that need to do the work, in this case small generators
    ii. **Option 2:** DNOs contract appropriate specialists to undertake all the necessary changes, and provide assistance, for affected generation owners, funded from BSUoS
14. Attendees asked a number of questions around the number of sites affected, generation volumes and the ensuing costs of carrying out the work. GS explained that the Workgroup believed that the changes would not affect domestic solar, and that the costs were currently estimated at around £6m but could potentially rise up to £10m as there is difficulty and uncertainty in gathering the information.
15. One attendee noted that for GC0035 generators >5MW parties were required to pay the costs themselves. For option 2, this would therefore raise an issue of discrimination – why should larger generators pay their own costs, and then pay those of smaller generators? If the issue of discrimination was raised could this re-open GC0035? It is also not cost reflective. GG suggested Ofgem's views should be sought.
16. TCMF attendees noted their concern also about the uncertainty around the numbers and therefore the risk that the cost of this scheme could rise compared to initial estimates. Attendees considered slides 40 and 41 looking at costs and benefits for impacted parties. GG requested that the potential positive impact to NGET (via balancing costs) be captured here also. Another attendee asked over what timescale the cost would be recovered via BSUoS – GS said this was potentially 2-3 years. PB asked whether there might be some way of aligning any cost recovery with the incurred benefit.
17. GP noted that it was a shame that this level of detail was not considered for GC0035. He also questioned whether BSUoS was the right means of cost recovery given that this is meant to reflect a half hourly cost. What about recovering from DUoS? Then Ofgem could incentivise it. A further attendee noted that for 12 out of the last 15 incidents of ROCOF these were caused by interconnectors - but under these proposals they would not be paying these costs (they do not pay BSUoS).
18. The group lastly noted that it might be helpful to disaggregate the issue of the work being undertaken by a central party and who pays for it.

5 Offshore generator local tariffs – Jo Zhou

19. JZ presented some slides to explain that OFTO revenue streams are subject to a number of adjustment items each year. Offshore generator local circuit charges, recover the majority of the OFTO revenue, but these are adjusted by RPI each year and hence may not reflect any changes to an OFTO's revenue.

20. GG asked about the magnitude of these revenue changes and whether there were any components that were different to adjustments to the onshore TOs revenue? JR noted that Ofgem publish a report each year to look at OFTO performance and this includes information on the revenue adjustment items. The latest report (Dec 15, reporting on the 14/15 financial year) can be found at https://www.ofgem.gov.uk/sites/default/files/docs/offshore_transmission_ofto_revenue_report_november_2015.pdf AM noted that the re-financing mechanism was an example of a revenue adjustment specific to OFTOs. GG asked if there would be similar mechanisms for any future CATOs (Competitively Appointed Transmission Owners)? The group thought this was likely, though it would depend on e.g. how expansion factors are calculated.

21. An attendee suggested that this 'gap' (between an adjustment to OFTO revenue and the local circuit charge being paid by the offshore generator) could be positive or negative and JZ confirmed that this was the case. GG noted that it would be helpful to understand the overall trends and whether over time there tends to be a trend towards under / over forecasting, JR noted that this could be looked at via the Ofgem reports referenced above.

22. A further attendee asked how pertinent this issue was, are many parties asking about it? WM confirmed that 2 parties have been in touch with National Grid to discuss this issue.

6 HH Elective metering and TNUoS – Damian Clough

23. DC introduced this item, re-capping on previous activity in this area, including CMP241 which was raised to prevent Suppliers being overcharged as a result of the implementation of P272. The issue here was that for a meter moving from NHH to HH mid-year, they would incur NHH charges for part of the year (4-7pm daily) but then also potentially pick up the full Triad charge in winter. To address this issue CMP241 mandated that all meters migrating on or after 1st April 2015 as a result of P272 (profile classes 5-8) are treated as NHH up until the implementation date of April 2017 (further detail can be found in appendix A of the slides). After this point they are to be treated as HH.

24. However in future as *all* customers migrate to HH charging, a further change to how TNUoS demand charges are levied will need to be made. 2 options are being considered:

    i. **Option 1**: All meters in Measurement Classes E-G are charged as per the NHH methodology up until HH settlement is mandatory (anticipated 2020 – the implementation date would be linked into the CUSC). (Meters previously charged as HH will be charged NHH from April 2017 onwards until mandatory settlement)

    ii. **Option 2**: Meters which were classed as Profile Classes 1-4 are charged as per the NHH methodology up until HH settlement is mandatory. Old Profile Classes 5-8 are charged under the HH methodology from April 2016 onwards

25. In both cases, actual data from HH metering would be used rather than profiled data where it is available.

26. 2 further options have been considered but National Grid perceive that there are difficulties in the timescales required:

    i. **Option 3:** Customers can choose which methodology to be charged under (this is difficult due to the fact that NG and Elexon system produce aggregated data so delineating individual customers would be highly challenging)

    ii. **Option 4:** Meters are charged under the HH methodology for the first full charging year after electing to be HH settled (difficult due to the fact that being HH settled will reduce potential switching times for customers and also that many profile classes 5-8 signed fixed term contracts)

27. The slide appendices explain in more detail the kinds of system and data changes that could be required.

28. DC noted that National Grid will be looking to raise a modification in this area shortly. GG noted that any future solution would need to be carefully considered to ensure it does not dampen incentives around demand side response. GG also noted that if HH metering is deemed to be beneficial to the consumer (in terms of giving them more options to take advantage of TOU tariffs etc.) any option that delays a move to HH metering could be seen to disadvantage such groups of customers.

7 Next meeting

29. No further issues were raised.

8 Next meeting

Next meeting: Wednesday 6th July 2016

Time : 11am

Venue : National Grid House Warwick