Structure of charges: Implementation Steering Group meeting

Tuesday 5 July 2005, 10:30am
Ofgem, 9 Millbank, London

Attendees:

Ofgem:	Mark Cox (Chair)	
	Martin Crouch	
	Colette Schrier	
	Clover Powell	
DNOs:	Andrew Neves	CN
	Jonathan Purdy	EDF Energy
	Tony McEntee	SP
	Mo Sukumaran	SSE
	Nigel Turvey	WPD
	Simon Brooke	UU
	Andy Jenkins	CE Electric
Generator Reps:	Malcolm Taylor	AEP
	Vishal Patel	RPA, Alcan
Supplier Reps:	Andy Manning	npower
	Sarah Owen	Centrica
IDNO Reps:	Liam Warren	Laing Energy
	Gareth Jones	IPNL
Apologies:	David Tolley	RWE
	Mike Harding	Laing Energy
	Max Lalli	SSE
	Carole Pitkeathley	energywatch
	Hugh Mortimer	BOC
	Dave Sowden	Micropower Council
	Jeremy Nicholson	EIUG
	Afroze Miah	Powergen
	Jim Johnson	GUC
	Marie Clark	SP Retail

1. Introduction

Mark Cox welcomed the group. Clover Powell provided a summary of actions from the last meeting (12 April 2005) and noted that Ofgem had been in touch with energywatch (following queries at the Structure of Charges (SoC) workshop on 24 May 2005) regarding renewing their involvement. Carole Pitkeathley will join the ISG distribution list, and will she will confirm with Ofgem whether an energywatch representative will be available to attend the August/subsequent meetings.

2. Summary of responses from May document

Mark Cox went through some slides summarising the main points from the responses to the May SoC consultation document. Discussion sessions were held following presentation of each of the key sections.

Charging principles and cost drivers

Two DNO representatives agreed that losses were not a major cost driver, one noting that the Cambridge report discussed in the document seemed to assume load lumped at the end of feeders, whereas loads were more likely to be distributed along feeders, which had a different effect on losses. A generator representative noted that the Cambridge report also seemed to misunderstand the nature of the market, in that it suggested that DNOs could 'trade' losses. Ofgem noted that the broader point being made was that DNOs were exposed to an estimate of the cost of losses through the losses incentive.

A DNO representative suggested that while the responses had identified fault level as a main driver for EHV generation only, this could change with significant penetration of generation at lower voltage levels.

Charging models

A DNO representative questioned the suggestion that the Distribution Reinforcement Model (DRM) only looked at the cost of the current system, and another DNO agreed that since it modelled a theoretical network, it was possible to base it on the network a DNO would build in the future, rather than replacement of current assets.

A DNO representative doubted that triad charging as used on the transmission network was a driver on the whole distribution network, but a generator representative suggested that distribution triads could be created reflecting distribution rather than transmission costs.

A supplier representative pointed out that complex cost reflective charging models can still result in simple tariff structures, if the DNO chooses.

Ofgem summarised that the responses had demonstrated that this was an area where there was a significant range of views.

Locational charges

Some DNOs reiterated their responses that locational signals were best placed in connection charges, and that the current boundary should not be made shallower. There was also concern from the DNOs that locational charges at lower voltages would be complex. One suggested that since new connections accounted for only 1% of customer numbers a year, even here the potential for influencing location was small. Ofgem questioned the suggestion that there should be no locational charges at all, given that the DNOs currently choose to employ site specific charges for EHV connections.

Specific charging models

Some DNO representatives were concerned that the University of Manchester/UU model could be volatile. UU suggested that the effects could be dampened by changing the assumptions in the model, but there were some concerns about the incentive effects

of generation connections in Cumbria creating negative demand charges. However, the group noted that in reality negative demand charges were unlikely.

A DNO representative noted that their work suggested that DCLF models did not provide as accurate charges for distribution systems as ACLF models, which better reflected reactive costs. Another DNO noted that in the past they had attempted to identify 'hot' and 'cold' spots on their network and charge accordingly, but these had proved complex to define, especially in areas where capacity limits were close to being reached. Ofgem noted the concerns expressed about locational UoS charges, but added that there were also problems with loading locational messages into deep connection charges.

Connection boundary

A DNO representative responded to generators' concerns that costs had risen under the new connection boundary with the suggestion that this was because they had been undercharged under the previous regime. He considered that past generation connections had only chosen the sites where connection charges were very low, and it might be appropriate that they paid more now. It was also recognised that the opposite situation might also be true, but that this was an inherent problem of average charges.

CE Electric clarified that their response on the annualised connection charges referred to a potential solution to adopting a deeper connection boundary. Ofgem suggested that this was essentially the same as site specific use of system charges, and other group members noted that this might be complex for developers to cope with, or be akin to DNOs offering credit. Another DNO noted that they had offered deferred connection terms in 2004, but it had not been taken up by any generators. Ofgem also noted that there was nothing to restrict DNOs from offering these terms now.

A DNO suggested that changing the boundary would need to be done at price control time, since it would have an effect on capex.

Another DNO noted that creating a common connection boundary between transmission and EHV would only shift a problem further down the network, creating a new boundary at 33kV/HV. Ofgem noted that there were wider issues of consistency.

Scaling

EDF Energy clarified that their comment on 'real' costs which did not require scaling referred to EHV charges. Ofgem questioned whether this represented historic costs only. EDF Energy said it represented costs that did not require scaling. CE Electric clarified that their comment referred to a method of revenue apportionment that would determine the split of revenue recovery from each group, and therefore no overall scaling methodology would be needed.

A DNO noted that customer preferences on scaling methods obviously depended on whether charges were being scaled up or down. Another DNO said that their experience suggested that distribution charge scaling tended to involve significant scaling up, due to the influence of security standards and the lumpiness of investment. A generator representative pointed out that of NGC's total end charge, only 20% is a locational element. A DNO also noted that Ramsey pricing could have an unfair impact on the fuel poor, who were both inelastic and vulnerable to price rises.

A supplier representative suggested a potential problem regarding reactive charges: these would be an output of the model, but as an excluded service, would they then have to be excluded from charges before these were scaled? A DNO said that currently reactive charges are not scaled, since they are a fixed assessment of the cost of reactive power, applied as an excess p/kVArh charge.

Commonality of models

A DNO representative said that they supported commonality of charge setting model between the DNOs, but not of tariff structure, since this would stifle tariff innovation. Another DNO suggested that they too would be happy to adopt a common model, but this would need to be based on their own assessment of a number of potential models, and they did not feel this information was yet available to them. Two DNOs noted that they would not support the adoption of the NGC ICRP model.

The DNOs noted some concerns about adopting a common tariff structure, and was agreed that there was room for variation within this, since tariff components could be set at zero if the DNO chose. Billing systems were raised as a possible barrier, and it was suggested that there might be 2 or 3 different supercustomer systems between the DNOs, and 5 or 6 HH systems.

A supplier representative said that there would be great benefit in common tariff structures (even if some elements were zero for some DNOs), especially for HH tariffs, where there was most difference between the current structures. He suggested that the issue of whether pricing signals in tariffs were passed on to end customers was not of great significance, as it would be just as efficient for suppliers to respond on behalf of consumers, and determine the structure of their own tariffs as they thought best.

Andy Manning agreed to put together a summary of the main issues for suppliers surrounding tariff structures, in order for the group to ascertain how much of a limitation current billing system differences would be to moving this issue forward.

Action: Andy Manning (npower)

A generator representative suggested that complete commonality between DNO areas would never be achieved due to different charging bases, but that this made transparency of charging models all the more vital. He suggested that although not everyone would be capable of running the models, there was no reason that consultants could not produce tariff tables and undertake analysis on behalf of connectees. A supplier representative noted that industry would also need some revenue information and an understanding of the scaling process to create a more accurate picture of charges.

The group considered whether confidentiality of information could be a barrier to model publication. A DNO suggested that customers tended to be more sensitive about their kWh usage and less so about their maximum demand/capacity. Another DNO said that they had not considered this in detail, but saw some potential for the publication of investment cost forecasts to offer a competitive advantage to independent connection providers. Ofgem pointed out that most of those costs would not be part of a UoS model. A DNO noted that network load data is published as part of the long term development statements, but that DNOs come up against confidentiality issues here too.

Generator charging from 2010

Some DNOs suggested that more work was needed to determine who had or hadn't paid deep connection charges, and that it might be necessary to have a cut off point, since very old data (ie 1960s) would probably be unavailable. Ofgem asked about the wording of connection agreements: did these state specific access rights, or make it clear that no further charges would be payable? A generator representative suggested that property rights would suggest that if there was no definite contract, and no objection to the continued occupation of the site then the generator might well have quite strong rights to continue on the same basis. He also noted that until a few years previously, all generators on the transmission system had assumed that they had firm rights. A DNO said that property rights on the distribution were by their nature leasehold rather than freehold, and there was no clear definition in the connection contracts of what charges might be attached.

A DNO suggested that generators with 'evergreen' rights should still be responsible for replacement and maintenance costs, but admitted that the contracts were probably unclear on payment of these costs. Another DNO pointed out that O&M factors in connection charges might cover replacement costs.

The group agreed that a clear and workable solution was needed for this issue, and that it was important to reach a conclusion that took account of the Government renewables targets for 2010.

Line loss factor (LLF) methodologies

A generator representative reported that the Elexon ISG, the SVG and the BSC Panel were still very much aware of the LLF issue, and were keen to understand what Ofgem's plans were for progressing this over the next year. Ofgem said that it was considering the next steps in the review, and would be speaking to the DNOs further over the summer.

Project leadership

A generator representative suggested that model commonality would not be achieved without Ofgem leadership, since this was naturally more of a concern for customers and suppliers than it was for the DNOs. A DNO suggested that suppliers need not understand the charging model, as long as charges remained stable and predictable, but the supplier representatives refuted this, suggesting that being able to predict charges necessarily meant understanding the model, and commonality would also make this process easier.

Conclusions

A DNO said that he had doubts about the way forward: he felt that the principles of commonality did not necessarily accord with the suggestion that it was for the DNOs to bring forward changes to their own methodologies, and it should be clear whether this was a DNO/Ofgem project or a less focused obligation on the DNOs to meet their licence objectives. Ofgem noted that this was the purpose of agenda item 3.

3. Longer term framework – next steps

Ofgem asked the DNOs to outline their work plans for the next few months.

WPD

Nigel Turvey told the group that WPD would be submitting a proposal to Ofgem to cover off the condition on the transition of EHV UoS charges by the end of August.

He also provided an update on the work currently being undertaken with Bath University on an ACLF model for their network, which establishes unit costs per MW per km of line and unit costs per MVAr per km of line. Some work had been done on DCLF, but this had been found to produce inaccurate generation charges, with charges coming out as negative despite the fact that reinforcement needed to be carried out. Other issues had also been encountered, including the difficulty of predicting generators' output at time of peak demand and the need to scale to take account of asset indivisibility, revenue requirements and security factors. The model was also quite data-hungry, although WPD considered that this might be less of an issue once the model was established, and it seemed that the model would realistically only be implemented at EHV. This then raised the question of how to deal with HV and LV charges: the model could produce charges at 33kV nodes, which could possibly be averaged across the customer base at each one.

WPD also noted some regulatory concerns about the model: it assumes a shallow boundary, and it also seemed to create considerable income from reactive charges. They were also considering whether the split of revenue between the EHV system and lower voltage systems could be established from the new price control reporting of MEA value per annum per voltage level, although this might create issues if the MEA value was different to the RAV. WPD noted that they had not considered whether the model could create LAFs yet.

WPD noted that the were currently working on a whole network scenario to examine whether the model could be scaled up, and although a great deal had been achieved since April (when the project began), they would have a clearer idea of the viability of the project for producing a workable charging model by September. Implementation of a new model would be April 2007 at the earliest.

CE Electric

Andy Jenkins told the group that CE Electric was working on covering off the conditions on their current charging methodology. CE Electric was also beginning to look at the longer term, and thought that it would be possible to implement new arrangements by April 2007, provided that there were no issues which would need to wait until DPCR5.

CN

CN were also concerned by the condition on their current methodology, but had recently written to suppliers to inform them of some changes to tariff structures they would be making for April 2006. CN noted that they have not yet done any work on the longer term framework, but were planning to begin once they had more clarity on the outcome of the current process.

SP

Tony McEntee said that they would be making some minor changes for April 2006. Development of a long term solution was at a very early stage, and they were doing some work to look at their forecast investments, but had not looked at any models yet.

EDF Energy

Jonathan Purdy said that EDF Energy would be submitting changes to cover off the condition on their EHV charges in August or September. Beyond this, they were looking at tweaks to the current methodology, and focusing on achieving commonality between their three areas. They were also keen to focus on their LLF methodologies. For the longer term, they were considering whether the Network Asset Management Plan (NAMP) could provide them with data on long run costs. EDF Energy noted that they considered that an impact assessment was necessary before they would consider carrying out any major work.

SSE

Mo Sukumaran told the group that SSE was looking at changes to its charging statement to improve the clarity and presentation of this, and was considering simplifying/rationalising the application of the charging structure without changing the methodology. SSE was also looking at the impacts of various options for the long term charging arrangements, and whether these might result in significant price changes at EHV. SSE were also considering the changes that would be required to bring the LLF methodology for Scottish Hydro Electric into line with Southern's methodology.

UU

Simon Brooke provided an update on UU's work with the University of Manchester. The last phase of the project finished at the end of January 2005, and UU had been considering next steps since. Goran Strbac was considering some work on a cost-benefit analysis, and UU would also be considering application of the model. UU noted that the costs of development lay in data gathering, rather than the commissioning of model studies. UU also noted that they would be submitting a proposal to cover off their EHV charging condition in the next couple of months.

Ofgem asked the group whether those who were only considering small changes or tweaks had based this on customer or supplier consultation. UU, EDF Energy and SSE noted that they had had some meetings or comments from customers, and SP suggested that they would consider consulting at the same time as submission of proposals to Ofgem.

The issue of IDNO charging methodologies and plans was also raised. Ofgem said that conclusions on a range of IDNO charging and price control issues were due to be published soon, and it was appropriate to wait to consider this question until Ofgem's conclusions had been made public.

Next steps

Ofgem said that they would be contacting the DNOs to get detailed information on project plans, including costs, resource allocation and timings. If an assessment of costs and benefits were to be carried out, this would require the DNOs to detail the costs of meeting their licence criteria, so that Ofgem could examine the costs of each option.

Action: Ofgem

Martin Crouch reminded the DNOs that submissions of costs should be numbers, not words, and told the group that Ofgem considered that it was not legally obliged to carry out an impact assessment at this stage. The onus would be on the DNOs to provide robust information. Ofgem would consider its work programme in advance of the next ISG meeting.

He also reminded the group that the time before the next price control was an opportunity to address long term charging arrangements, but that if this was to work, it would require the development of clear, concrete models by the end of 2005 or the beginning of 2006.

ISG

A generator representative said that there might be benefit in establishing a distribution charging methodology forum in the future, but for the time being there was value in the ISG continuing, given that conceptual issues were still being considered. The group supported the continuation of the group, and Ofgem noted that as the DNOs' development work progressed, more DNO input would be welcome in terms of submissions and suggestions for agenda items. Mark Cox thanked everyone for attending.