Structure of electricity distribution charges

Ofgem workshop – 24 May 2005

Ofgem, 9 Millbank, London SW1P 3GE

The workshop was hosted by Ofgem to allow industry representatives to discuss issues relating to the structure of electricity distribution charges review, and more specifically, the issues covered in the Ofgem consultation document published on 9 May 2005[1].

The workshop was attended by Distribution network operators (DNOs), suppliers, independent DNOs (IDNOs), academics, large demand customers, generation customers, National Grid (NGC), developers and industry consultants. Following an introduction from Ofgem, the workshop split into four breakout groups for the morning, then reconvened for the afternoon session to hear presentations from the groups' chairman and debate their conclusions.

This note summarises the breakout groups' findings and provides a minute of the afternoon presentation and debate session. The groups were asked to consider questions based around the Ofgem consultation document, and either draw conclusions or highlight areas of difference of opinion.

Breakout group 1

Terms of reference

Cost drivers and charging models: what are the key cost drivers on the distribution system, and what kind of model would reflect these and incentivise efficient investment and customer behaviour?
Consistency: what are the arguments for / against consistency or commonality between DNO models? How is this affected by the fact that DNOs' revenue requirements are all different? Is there a potential trade off between consistency and innovation?
Publication of models: what level of transparency is needed? What are the risks or issues associated with publishing models in full? How should the charging methodology statements' functionality be improved from the current starting point?
IDNO charging: are there any issues associated with charging IDNOs and the approach that should be adopted?

Group 1A[2] presentation summary

- Main cost drivers: capacity (taking into consideration power flow, voltage level and fault level issues), and time of use. kWh consumption was not considered to be a cost driver.
- Consistency: differing revenue allowances do not rule out the use of a common model between DNOs. The group noted a trade off between transparency and clarity (which would be aided with a common model) and innovation, which might be stifled if a common model was implemented. However, the group felt

[1] Available from the Ofgem website at http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges
[2] Group 1 was split into two parts, due to numbers. The groups considered the same topics, but presented separately. Due to a technical fault with the presentation slides, these are not available to publish, so the group's conclusions are summarised in this note instead.

that a common model could be implemented in terms of adopting a high level generic approach and allowing some degree of flexibility below this, for example DNOs could adopt different approaches to model inputs.

- Publication of models: the group considered that it was important to publish enough information for suppliers to understand the charge setting process, but some customer-specific information might be considered confidential. It was noted that publication of the model would impose additional costs on DNOs and might lead to more questions from users.
- IDNO charges: should be set as for any other exit point, i.e. as a single customer.

Group 1B presentation summary

- Forward looking costs would lead to economic development of the network, but historic sunk costs may distort these signals due to the adjustments made to charges to ensure revenue recovery. The use of forward looking costs for UoS charges may increase unpredictability and a supplier representative noted that hedging this risk might be sensible. The group thought that it would be important to be able to predict UoS charges in to the future.
- Cost drivers: the group thought that capacity, voltage and fault levels were all important cost drivers that needed to be considered although these may be dependent on time of use. It also noted that quality of service (QoS) and losses price control incentives would change the network and hence the baseline on which charges are set but were not cost drivers in themselves.
- The group thought that demand and generation could be treated symmetrically within a charging model but that this may not be appropriate. The issues raised were inconsistent cost drivers between demand and generation which may restrict the ability to be completely symmetrical, e.g. fault levels, and the lack of a generation planning security standard.
- Consistency: was supported, but the group identified that there was both consistency in methodology and also consistency of application. It was recognised that even with consistent methods, each DNO would produce different charges.
- Publication of models: was supported, but the group recognised the issues raised by Group 1A.

Group 1 question session

A generator representative asked for clarification of the group's suggestion that generation and demand could not be treated symmetrically, and questioned whether this arrangement could work for CHP plant. A group member explained that the statement referred to the situation at transmission level, where generation and demand charges are equal and opposite: the group considered that this was not workable at distribution level, where charges might have to be asymmetrical, even though common treatment had been applied. An academic noted that P2/5 and P2/6 were both demand driven standards, and that while these took account of the security of demand connections, the security of generation connections had thus far been handled on a bilateral basis.

An IDNO representative raised a concern about the possibility of double counting for connections to IDNO systems, where use of system (UoS) charges from the DNO's system might cover assets installed by the IDNO and would therefore be paid for upfront, but then also covered by the DNO UoS charge.

The workshop acknowledged that metering would be an issue in the introduction of new charges, and that should new arrangements rely on the installation of more sophisticated meters, the costs would have to be covered by suppliers (thus eventually end consumers).

The group noted that locational variation in charges had not been covered in detail, but that it was a major issue.

Breakout group 2

Terms of reference

Generator charging from 2010: what are the options for bringing existing generators into the longer term arrangements, and how should the timing of this process be handled?
DG and deferred expenditure: what are the benefits that parties might bring to the system? How can these be accurately quantified and attributed? What are the practical issues associated with this issue?
Reactive power: what is the best way to identify and reflect the costs of poor power factor, and incentivise efficient operation? How should the differences between demand and generator power factor be handled in charges? What physical (eg metering) restrictions might have an effect?
Interaction with transmission charging: are there issues over the interaction of transmission and distribution charges, and if so, which are within the scope of this project?
Changes to charges: if revised arrangements cause disturbances in charges, how should these be handled? Do disturbances remain an issue as transparency of the charge setting process increases?

Group 2 presentation summary[3]

Options for charging from 2010

- Do nothing – generators have evergreen rights, and may have made investment decisions based on this assumption.
- Connection charges could prove to be the same between old and new regimes, therefore there would be no need to apply refund and GDUoS could apply automatically from 2010, reflecting new costs such as reinforcement, NGC charges and O&M.
- Need to determine clear system for determining value of access right now, as this could well be taken to determination.
- Consistency of approach between DNO areas is key, and there should not be discrimination between demand and generation – demand has coped with a number of changes to connection boundary without transition – eg removal of TSA.

Deferred expenditure

- Quantifying and attributing costs: P2/6 allows DNOs to reflect benefits of deferred expenditure, but only to single generators. The group also noted differences between the way services would be reflected – for some services (eg

[3] Group 2's presentation slides are available from the Ofgem website at http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges.

system support) this would probably be done contractually, while for others (eg reductions in losses) this would feed into the charging model.

- DNO price control: the group noted that currently separate pots for demand and generation may prohibit reflecting deferred expenditure, but that if penetration does not increase significantly in the next few years, 2010 may be sufficiently soon to handle this issue.
- Location of generation and demand not coincident at the moment, but with 20/30% penetration this could change, and begin to influence planning. However, costs could be lumpy – generation could defer 132kV spending, but increase LV/11kV costs.

Reactive power charges

- May be a billing legacy issue rather than one of principle – there are currently 5-6 billing systems in use.
- Differences between demand and generator power factor: 'poor' power factor is not necessarily same for all parties – will be contractually arranged for some generators providing ancillary services.
- Grid Code: some generators may be providing a service to NGC (as obliged by the Grid Code) but will be made to pay by DNO for reactive power.

Interaction with transmission charging

- The group was concerned that it was not practical to treat exporting GSPs as negative demand, and it might be better to treat them as generators instead (ie DNO TEC). Currently DNOs have no right to export onto the transmission system under the Connection and Use of System Code (CUSC), and systems assume GSPs are importing.
- Some generators of <100MW may be causing costs on the transmission system, but as these sit behind suppliers these are hard to identify.
- DNO group members noted that traditionally all transmission costs levied on DNOs have been borne by demand customers – this may no longer be appropriate, especially at generation-only GSPs.
- Need to get consistency and clear charging regime within a year – currently projects are assuming full TNUoS costs as worst case scenario, and therefore failing.

Movement in charges

- Volatility disliked.
- Regulatory or government intervention should be timely and predictable, and IAs are supported for any Ofgem led changes.

Question session

An academic raised the issue of sending locational signals to generators, and suggested that there was benefit to making some attempt at zonal pricing. The suggestion that zones should be locked for five years and then reassessed was considered, but a group member noted that this increased the likelihood of step changes in charges, rather than more gradual movement.

A generator representative suggested that locational charging signals would not affect the siting of generation plant since other factors come in to play that are more material considerations, e.g. renewable targets.

A DNO representative questioned whether the price control forecasts of generation connections were insufficient for the purposes of charge setting, and suggested that overly complex models were not needed.

Breakout group 3

Tariff structures: is the current structure and number of tariffs appropriate? To what extent are these cost-reflective? What are the reasons for/effects of inconsistency between DNO application of fixed and standing charges? What access rights are granted by the payment of DUoS, and should long or short term access products be offered?
Metering: to what extent might current metering and profiling arrangements act as a constraint on cost-reflective distribution pricing?
Scaling: how appropriate are the different methods to scale prices to DNO allowed revenues?
LLFs: should the LAF/LLF methodologies be published / common among DNOs / common for demand and generation? To what extent are site specific factors appropriate? Should all losses be included, or electrical losses only? What should the next steps on the LLF review be?

Group 3 presentation summary[4]

Tariff structures

- The group noted that the number / structure of tariffs requires review as structure of tariffs largely due to legacy issues
- Suppliers want simplicity and commonality between DNOs
- The group considered that tariffs are cost reflective to some extent but zonal and seasonal / time of day tariffs may be better
- IDNOs want transparency of costs at each voltage level
- Fixed / variable charge split appears to be arbitrary; suppliers want commonality
- Access rights – DNOs have an obligation to connect, and law currently suggests evergreen right to capacity

Metering

- Group thought costs of implementing any new metering regime are likely to outweigh the benefits; however metering may be required for reasons such as energy efficiency
- Detail of metering arrangements for CVA customers needs attention
- Profiles are not currently a constraint. Recognise that could look again at the number of profile groups, and that new profiles will be required to cover new generators without meters.

Scaling

- Ramsey pricing inherently discriminatory - not fair to domestic customers
- The group considered that a percentage adjustment option was simplest, and felt that it retained differentials
- The group was not sure how a uniform mark up would be applied

[4] Group 3's presentation slides are available from the Ofgem website at http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges.

Line loss factors

- The group agreed that line loss factor methodologies should be published by the DNOs
- The methodologies should be as consistent as possible across DNOs
- Site specific factors are justifiable
- There is merit in certain types of non-technical losses being included in LLF
- The group supported the establishment of a working group to consider the issues further
- Issues for consideration by this group would include:
    - relationship between power factors and losses
    - impact on supplier billing systems
    - CVA/SVA.

Question session

An academic suggested that scaling could be rendered unnecessary if charges actually reflected the true marginal cost of a greater or lesser take to the supplier and the DNO, and that cost reflective charges should be capacity based. A DNO representative noted that capacity information is lacking for LV customers, and that attempts to bring in half-hourly-type charges for non half hourly metered sites had failed because all NHH usage was profiled. The academic suggested that these were not insurmountable obstacles, and that innovation in tariffs was long overdue, since the current structure had been essentially unchanged since the 1960s.

Another group member noted that the savings from this kind of major change would be minimal, but the costs of implementation would be huge. It was also noted that the role of suppliers in passing on messages created by new models would be vital to the success of any reforms.

Ofgem noted that there were a number of themes emerging from the presentations and discussions: the need for more transparency on the charging models, and more simplicity and commonality in tariff structures.

Next steps

Ofgem presented some thoughts on the timetable for the development of the longer term arrangements:

- 20 June 2005: responses to the consultation received.
- 2005 – development work on long term charging models:
    - Building on Ofgem conclusions on high level framework (Summer 2005),
    - Led by DNOs, informed by industry consultation and academic work, supported by Ofgem.
- 2006/07 – Implementation of longer term arrangements.

AOB

One attendee noted the lack of representation of domestic customers (energywatch) at the workshop.

One attendee questioned why the issue of the connection charging boundary had been omitted by Ofgem. Ofgem explained that this was still a question for consideration, and no decisions on further movement in the boundary had been made. Ofgem also noted that a number of issues that the May document raised had been covered at the workshop.

A generator representative wondered whether any harmonising pressure would be exerted, should the DNOs' methodologies seem to be diverging significantly in the future. Ofgem suggested that while there was no formal licence requirement for commonality, the licence objectives were the same for all, and there could be benefits to commonality in arrangements. Concern was also raised that the obligation for constant review of the methodologies could result in frequent change and volatility in charges.

Ofgem thanked the group for attending and contributing, with particular thanks for the chairmen of the breakout groups for volunteering and presenting to the main workshop.