# Next steps in delivering the electricity distribution structure of charges project

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**Target Audience:** Generators, distributors, suppliers, customers and other interested parties

**Overview:**

This document sets out our decision on next steps for delivering the structure of charges project for electricity distribution businesses. The project seeks to achieve a common, cost reflective charging methodology with open governance arrangements across all 14 Distribution Network Operators in Great Britain by April 2010. In October 2008 our proposals to place new licence conditions on the DNOs were blocked by two of the seven companies owning distribution companies who did not agree with our view of the most appropriate methodology for the highest network voltage levels.

In December we consulted on how to take this project forward. Our decision is to propose new licence conditions that will ensure implementation of a common methodology and governance at the lower voltage levels for April 2010. At the highest voltage levels we have decided to allow DNOs to choose between two charging models. We will use the next price control period to assess the impact the methodologies have on capital expenditure efficiency and will take steps to ensure that customers do not carry the cost of expenditure that could have been avoided through more cost reflective charging.

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## Context

Delivering the electricity distribution structure of charges project remains a priority for Ofgem. The move towards a low carbon economy and the government's 2020 targets for reducing carbon emissions means that patterns of use and investment on the distribution networks will change. Distribution Network Operators (DNOs) are forecasting very significant load related investment (£2.3bn net of customer contributions) on their networks between 2010 and 2015. Given the significant increase in energy prices in recent years, increasing fuel poverty and the increasing pressures on business and domestic customers due to the current economic outlook, it is important we do all we can to have more cost reflective charging. This will encourage more local, low carbon generation to connect closer to demand at distribution level. This will help make sure the 9GW of distributed generation forecast to connect to the distribution networks between 2010 and 2015 is rewarded where network benefits are provided by such generation. It will also encourage more energy efficiency from existing customers.

Revised charging methodologies are needed to encourage significant new loads with flexibility over where they locate to site where spare capacity already exists or away from parts of the network where it will be more expensive to connect them. A common methodology at the lower voltage levels on the distribution networks will deliver real benefits to customers and suppliers in terms of reduced administrative and charge forecasting costs, while common governance of the revised methodologies is necessary to ensure that the benefits of commonality are preserved, and to ensure the methodologies respond to changes in the needs of network users. We are keen to ensure that DNOs maintain momentum on this project so that benefits are reaped by stakeholders in a timely fashion. Responses to our December consultation on next steps indicate unanimous support for Ofgem continuing to pursue delivery of the project and support for the steps the DNOs have taken since October towards delivering a common charging methodology and governance at the lower voltage levels. These responses have driven our decision to split the project delivery timescales between higher and lower voltage levels.

## Associated Documents

- Next steps in delivering the electricity distribution structure of charges project: consultation document, 160/08, December 2008
- Delivering the electricity distribution structure of charges project: decision document, 135/08, and collective licence modification proposal 137/08, both October 2008
- Decision on a common methodology for use of system charges, consultation on the methodology to be applied across DNOs, and consultation on governance arrangements, 104/08, July 2008
- Delivering the electricity distribution structure of charges project, 36/08, April 2008

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## Summary

Ofgem has been urging electricity distribution network operators (DNOs) to introduce new, more cost reflective charging methodologies for several years. In our view cost reflective charging arrangements are necessary to encourage efficient siting and use of network decisions, particularly for larger users, and for rewarding users who provide a benefit to the distribution network, for example distributed generation (DG) located close to load or for customers implementing demand side management. Through our work on the structure of charges project we have also reached the view that common charging arrangements would provide benefits to network users, for example in reducing the time and effort suppliers need to spend in understanding the different methodologies of each DNO and in terms of the cost to suppliers of managing the risk of price changes across DNOs.

Given limited progress in achieving the project objectives we worked through 2008 to try to ensure delivery of the project for 2010, in line with the start of the next five-year price control period for the DNOs. During 2008 we consulted on, assessed the impact of and subsequently developed proposals for a common set of charging and governance arrangements across DNOs. This culminated in a collective licence modification (CLM) proposal in October to formalise the obligation on DNOs to deliver a common cost reflective charging methodology with open governance arrangements for 2010 in the DNOs' distribution licences.

Our proposals were rejected by Scottish and Southern Energy and Scottish Power Energy Networks, who with 4 out of 19 votes between them formed a blocking minority (over 20%) which prevented the proposed licence conditions taking effect. Their rejection was on the narrow issue of charging at the highest voltage levels reflecting the lack of agreement in the industry on the most appropriate methodology to apply. However, since October DNOs have been voluntarily progressing common charging arrangements at lower voltage levels for implementation in April 2010. We have been engaging in their work and are encouraged by progress to date.

In December we consulted on the next steps for the project. We sought to gauge the level of support for taking this matter to the Competition Commission (CC). In particular we wanted to hear from suppliers, generators, users and other interested parties who did not have the opportunity to vote on the proposal changes to the DNOs' distribution licences in October. We recognised the timing and resource implications of any CC referral and asked for views on alternative approaches for delivering the project objective.

In view of the complexity of our October proposals and the potentially difficult choices for industry parties to consider between the options for taking the project forward we offered to meet stakeholders to discuss the options around next steps on the project. We met bilaterally with a number of parties requesting a meeting prior to the consultation closing on 22 January.

Responses to the consultation showed a high degree of support for ensuring that DNOs continue their work on common charging arrangements at lower voltage levels. The majority view is that this will deliver significant benefits to industry parties. Responses also showed limited support for an immediate CC referral mainly

due to a concern that this may derail progress on common arrangements for the lower voltage networks.

Having considered these responses the Authority has decided to take a different course of action for charging at lower and extra high voltages. For the lower voltage levels, we will immediately commence work on a CLM proposal. This will require all DNOs to deliver charges based on a common charging methodology and open governance arrangements for the low voltage networks by April 2010. The licence modification will formally require the DNOs to complete the work they have already commenced within that timeframe. We do not expect this proposal to be contentious amongst the DNOs as it reflects their current work and expected timescales.

We have thought carefully about the way forward for EHV charging. Approximately £2.3bn of load related investment net of customer contributions is forecast on the distribution networks over the next price control (DPCR5) period. In the region of £1.6bn of this investment is forecast at EHV level and so we think it is important to encourage cost reflective charging at this voltage. We are concerned that without some step change in charging at this voltage level, customers may be required to bear an inefficient level of costs and there may be little progress in facilitating the connection of DG where it can alleviate network constraints. Equally, we recognise the disruption that a CC reference on this matter may cause and that there are complex and technical issues that mean the industry and independent commentators and experts are divided on the most appropriate methodology for this voltage level.

For EHV charging we have decided to require each DNO to choose whether to apply a common LRIC model or a common version of the forward cost pricing (FCP) approach developed by the G3[1] group. Following conclusion of our statutory consultation on the CLM proposal for the lower voltage levels, we intend to formalise the EHV charging requirement via a special licence condition obliging each licensee to implement open governance arrangements and their choice of a LRIC or FCP methodology by 1 April 2011. The detail of the governance arrangements at EHV needs to be considered further.

We have noted that there is no clear evidence that one of the two approaches to charging is better than the other and that our October decision on the common EHV methodology was finely balanced. We have outlined concerns over the cost reflectivity of the FCP methodology on a number of occasions. Given these concerns, and to ensure customers are adequately protected, as part of the general review of investment in the following (DPCR6) price control review we intend to scrutinise DNOs using the FCP method to make sure that it has not lead to inefficient capital expenditure because of poor cost signalling. If we find it has we will seek to disallow any inefficient expenditure.

[1] The G3 group comprises Central Networks, Scottish Power and Scottish and Southern Energy.

# 1. Introduction and background

Chapter Summary

In this chapter we provide an overview of the recent history and developments which form the context to the decision we have reached on next steps on the structure of charges project. We restate the rationale for the key components or our October CLM proposal, summarise the key drivers behind the project, and consistent with our December consultation, reiterate why delivering against these objectives is central to our decision on the way forward.

## December consultation on next steps

1.1. On 1 October 2008 Ofgem held a statutory consultation on a collective licence modification (CLM) proposal (the 'October proposal') to require the Distribution Network Operators (DNOs) to introduce a common distribution charging methodology and common governance arrangements by 1 April 2010. Four distribution licensees out of 19 objected to the October proposal creating a blocking minority. The statutory objections came from Scottish and Southern Energy (SSE) and Scottish Power Energy Networks (SP) who hold two DNO licences each. Both companies cited our decision to require DNOs to apply a Long Run Incremental Cost (LRIC) methodology at Extra High Voltage (EHV) level on the distribution networks as the reason for their objection.

1.2. Following the blocking of the October proposal on this narrow issue, on 11 December 2008 we issued a consultation document titled 'Next steps in delivering the electricity distribution structure of charges project' (the 'December consultation'). The purpose of the December document was to consult with industry on the best way of achieving the objectives for the project. As well as the views of the DNOs themselves, we were particularly keen to hear the views of those industry parties who did not have the opportunity to vote on the October proposal.

1.3. In the December consultation we set out our view that referring the matter to the Competition Commission (CC) would provide a clear landing on the issues associated with EHV charging that have divided the DNOs for many years. However, we recognised that this option could take several months and could be resource intensive, and so we also invited views on the costs and benefits of other potential ways forward including:

- consulting on a revised licence condition to implement new cost reflective charging and governance arrangements at lower voltage levels only (and referring the narrower issue of EHV level charging to the CC); or alternatively
- allowing DNOs the choice to pursue either the LRIC or the Forward Cost Pricing (FCP) approach at EHV level.

1.4. Responses to the December consultation indicate unanimous support for continued pursuit of delivery of the structure of charges project, but opinion on whether we should refer the matter for decision at the CC was mixed. Two DNOs and two suppliers gave qualified support for a decision to refer all or part of our October proposal to the CC with immediate effect, but among other industry respondents there was a consensus that significant benefit would accrue in achieving commonality at High Voltage/Low Voltage (HV/LV) level as soon as possible and that an immediate CC referral could undermine the progress now being made by DNOs in this respect.

1.5. Industry views on the way forward for the structure of charges project have been integral to our decision. The value placed on early delivery of the project objectives for lower voltage levels along with concerns that a CC referral could jeopardise delivery of commonality at HV/LV level for 2010 has had a significant bearing on our thinking. Full detail on our decision is provided in the following chapter and a summary of the non-confidential responses to our December consultation is contained in Appendix 1 to this document. All non-confidential responses are available to view in full on our website.

## October CLM proposal and drivers for the project

1.6. In our view the key drivers for the structure of charges project are encouraging efficient network investment, promoting sustainable development and promoting efficiency and competition among energy suppliers. The key elements of our October proposal reflect the key drivers for the structure of charges project. The blocking of the proposal means that the project will not be delivered for implementation in full by 1 April 2010. As set out in our December consultation, in reaching our decision over next steps it is critical that we find a way to maximise delivery against the principle drivers for the project.

1.7. Our October collective licence modification (CLM) proposal contained a package of measures which covered the four key areas of the structure of charges project. These included:

- Our decision to require a common methodology across all GB distribution networks: the number of different distribution charging methodologies currently in force is seen as an unnecessary source of complexity and inefficiency by suppliers and generators. Suppliers in particular consider that removing this complexity and implementing a single common methodology would deliver benefits in terms of efficiency, transparency, and reduced charging risk premium totaling multiple millions of pounds per year.

- Our decision over which methodology should be adopted as the common methodology at both EHV and HV/LV levels: respondents to our earlier consultations indicated they wanted us to determine the common methodology. In particular, this was in response to a long running debate in the industry as to the most appropriate distribution charging methodology, particularly at EHV level. It was principally to resolve this debate, and thereby create a foundation for the common methodology, that we took responsibility for reaching a decision on the model in our October proposal. Our view was that the pros and cons of FCP and LRIC were finely balanced, but we considered that LRIC would provide the more cost reflective foundation for the common methodology.

- Our decision to implement common governance arrangements for the common methodology: this was based on our view that without a central and common change process the common methodology could fragment over time, and on our view that DNOs have limited incentive to consider and promote methodology changes in response to market needs.
- Our decision that the common methodology should be delivered for implementation by 1 April 2010: this reflected the implementation of revised charging methodologies from the beginning of the next price control review period as well as the need to more cost reflective arrangements as soon as possible.

1.8. Full detail on the rationale for our October proposal can be found in our October decision document: 'Delivering the electricity distribution structure of charges project'.

## Further developments in the structure of charges project

1.9. Since the blocking of our October proposals, the DNOs have been working collectively towards developing a common methodology and governance arrangements at HV/LV level with a view to implementation by 1 April 2010. In particular, they have continued to jointly develop a common distribution reinforcement model (DRM) for HV and LV generator charges which recognises the potential for generation to benefit the distribution network by offsetting demand. The DNOs are also working with independent DNOs (IDNOs) on developing a common approach to IDNO boundary charging.

1.10. The work at HV/LV level has progressed under the auspices of the Energy Networks Association (ENA) where the DNOs have set up a central Common Methodology Group (CMG). The CMG has representatives from each DNO and in some cases other stakeholders and has set up five work streams looking at each of the following areas: 1) Power flow analysis; 2) DRM and cost allocation model; 3) Tariff structure and application; 4) Connection boundary review; and 5) Governance. The work streams are at different stages and have different remits[2], for example work on power flow analysis has currently been halted whilst the work stream for governance has been set up relatively recently.

1.11. The DNOs have a licence obligation to keep their charging methodologies under review and to propose such modifications to their methodologies as are necessary for the purpose of better achieving the relevant objectives set out in Standard Licence

[2] See the Energy Network Association's website for details of the work of each of the work streams along with supporting papers: http://2009.energynetworks.org/structure-of-charges/.

Condition (SLC) 13.3 of the electricity distribution licence. We see the work of the CMG to develop a common DRM as part of fulfilling this licence obligation. We have attended a number of the CMG work stream meetings and have provided written feedback to issues which the work streams have identified. We are keen to continue engaging with DNOs on areas of detail on the methodology and responding where thinking evolves and as issues are progressed, and we consider that it is appropriate that the DNOs continue to assume principal responsibility for progressing this work.

1.12. In the weeks leading up to our December consultation the work of the CMG was in its early stages. The work carried out by the group since this time provides a strong indication that the DNOs are serious about delivering this work. We are very supportive of the work being progressed by the CMG. In reaching our decision on next steps we have been mindful of the positive steps taken by the CMG and have considered the potential consequences of disrupting this work.

# 2. Decision on next steps

Chapter Summary

This chapter sets out the key components of and reasons for our decision on next steps on the structure of charges project. We set out our decision not to refer the project to the CC at this stage and explain our decision to split the project between delivery at HV/LV level and delivery at EHV level. We also provide an indicative timeline for progressing the work over the course of 2009 and beyond.

## Overview of decision on next steps

2.1. The December consultation closed on 22 January 2009. Since this time we have fully considered the consultation responses received, we have tracked the progress being made by the DNOs in terms of the common methodology work at HV/LV level, and we have considered the implications of a CC referral on the electricity industry at a time in the wider economy when resources are under considerable pressure.

2.2. This review has convinced us that the project objectives, and the interests of future and present customers, are not best served by a CC reference at this stage. This would have the potential to divert industry resources away from delivery of commonality at HV/LV level. Consultation responses have made it clear that there is a high value to suppliers and generators from a common methodology for lower voltages and that costs could be saved on behalf of customers. Similarly, the progress that DNOs have made on lower voltage charging and governance suggests that a CC reference is not needed to deliver the project objectives at this voltage.

2.3. Our decision is therefore to split the project between delivery at HV/LV level and delivery at EHV level. To deliver at HV/LV level we will propose a CLM obliging the DNOs to implement a common charging methodology and open governance arrangements at HV/LV level by April 2010. To take the project forward at EHV level, we intend to raise individual licence modification proposals which offer each DNO licensee the choice over whether to implement either the LRIC methodology specified in our October 2008 decision or a version of the FCP methodology developed by the G3 group by April 2011. We consider that this approach will deliver the significant benefits of a common charging methodology at lower voltage levels while providing a pragmatic way forward at EHV level which offers protection to customers and allows the DNOs to test the practical application of their chosen methodology.

## Delivery of common methodology and governance at HV/LV level

2.4. Responses submitted to the consultation show that there is a consensus across industry (particularly amongst suppliers and generators) that delivering a common DRM methodology and governance at HV/LV level will bring network benefits to

HV/LV connected distributed generation (DG) and efficiency benefits to suppliers in terms of reduced charging risk premia and reduced administration costs.

2.5. Our analysis indicates that although ten per cent of distribution network capacity is used by EHV connected customers and as much as 69 per cent of net load investment at the next price control (DPCR5) is forecast at EHV level, in terms of customer numbers, more than 99 per cent are connected at HV/LV level. This means that achieving a common methodology and governance arrangements at HV/LV level would deliver a significant part of the benefit industry and large suppliers in particular associate with the structure of charges project[3]. Table 1 summarises the data we have used in considering this issue.

**Table 1 - EHV and HV/LV share of capacity and forecast investment**

| | Number of customers | Capacity of customers | Forecast load investment (gross) | Forecast load investment (net) | Forecast DG connections |
|---|---|---|---|---|---|
| EHV | < 1% | 10% | £2.1bn (43%) | £1.6bn (69%) | 6.4GW |
| HV/LV | > 99% | 90% | £2.8bn (57%) | £0.7bn (31%) | 2.8GW |
| Main Impact | Retail supply | Investment | | | Renewables |

2.6. Consistent with the views of industry we agree that delivering a revised common methodology at HV/LV level would deliver a significant and important part of the structure of charges project for distribution customers. In a competitive market we would expect the efficiency savings derived by suppliers from a single common methodology to be passed on to customers by way of a reduction in energy bills. Further, open governance arrangements which we would require to be implemented in conjunction with the revised charging methodology, will allow suppliers and generators to propose modifications to the common methodology. We consider that this will provide a benefit to network users in terms of ensuring that the charging methodology is responsive to the changing needs of users.

2.7. As outlined in chapter one, we consider that the steps the DNOs have taken through the work of the CMG indicate that they are serious about delivering a

[3] It is also our understanding that contractual arrangements between suppliers and a large number of EHV customers allow network charges to be passed directly to EHV customers' energy bills. EHV level charging forecasts are therefore not as important to suppliers' revenue forecasts as HV/LV level charging forecasts are likely to be.

common DRM methodology and governance at HV/LV level. The DNOs have indicated that they intend to implement the revised methodology at HV/LV level by 1 April 2010, and we are satisfied that this represents a realistic timescale for delivery. DNOs have been working in this area for a number of months. We consider that an obligation to deliver common HV/LV charging and governance arrangements for 2010 is achievable by DNOs and in line with their current work plans.

2.8. To date the DNOs have made a voluntary commitment to this process and there is nothing binding to ensure that the obligation is enforceable. To varying degrees the DNOs have missed a number of deadlines throughout the history of the structure of charges project. For this reason we consider that it is necessary to introduce a CLM proposal which formalises the obligation on DNOs to deliver the common methodology and governance arrangements for implementation at HV/LV level by April 2010. Ensuring that the DNOs have a licence obligation to deliver a common HV/LV methodology was supported by a number of suppliers and generator representatives who responded to our December consultation. We consider that while the DNOs may be able to implement voluntary governance arrangements, these are best incorporated into the licence to ensure DNOs comply with them and to provide for Ofgem to take enforcement action if required.

2.9. Table 2 outlines an indicative timetable for this work, including the timescale within which we will consult on the revised legal text associated with an HV/LV CLM, and the deadline by which DNOs will be required to submit the common HV/LV methodology.

2.10. Indicative licence drafting for the HV/LV CLM is contained in Appendix 2. This drafting is based on the licence drafting consulted on as part of our October proposal. A limited number of cosmetic changes have been made to the structure of some paragraphs, but the principal material change has been the requirement to define the common distribution charging methodology (CDCM) as applying at HV/LV level only. Appendix 3 duplicates the HV/LV methodology provided in our October decision document. Appendix 4 then updates this to reflect the splitting of the project between EHV and HV/LV and to highlight issues which have been subject to additional work by the DNOs since October.

2.11. Given the publicly stated commitment among DNOs towards delivery of HV/LV commonality, and the work that has already been progressed towards this end, we do not expect our CLM proposal to be contentious amongst the DNOs. We note that Appendix 3 and the updates provided in Appendix 4 represent our best view of the HV/LV methodology at this point in time and are open to discussion where DNOs believe they have a better, or more appropriate approach to propose. Where this is the case we expect DNOs to fully justify the approach taken and to recognise the requirements in the CLM regarding derogations for individual licensees.

2.12. For the avoidance of doubt, we expect DNOs to continue to address the areas for future development set out in our October decision document proposals. Specifically we set out in our October proposals that the main elements that DNOs are expected to further develop pre-April 2010 concern IDNO tariffs, tariff structures, information to help users predict their charges and issues around implementation, for example to ensure arrangements reflect interactions with the price control review. Post-April 2010 we expect further work around stability, transparency and predictability of charges and charging models as well as consideration of issues around the balance of connection and use of system charges in the LRIC model.

## Delivery of the structure of charges project at EHV level

2.13. The most controversial aspect of the October proposal was the requirement on DNOs to adopt a common LRIC methodology for customers at EHV level. It was this aspect of the decision which caused SP and SSE to register objections to the proposal and for the proposal to fail. Our October decision at EHV level was not taken lightly. In our decision document we set out in detail that the pros and cons of the FCP and LRIC methodologies were finely balanced. However it remains our view that EHV charging methodologies can and should play an integral role in promoting efficient DG connections and network investment efficiency, and we continue to consider that the LRIC methodology would provide the most cost reflective foundation for a common methodology.

2.14. We have decided not to refer the matter of EHV charging to the CC at this stage because we think a CC referral would create an unnecessary diversion to the DNOs in their attempts to deliver the important benefits of commonality at HV/LV level. Nevertheless our decision to allow the DNOs to choose between implementing the LRIC methodology as set out in our October decision and a version of the FCP approach should not be viewed as a withdrawal from the EHV charging debate.

2.15. In their responses to the December consultation a number of respondents suggested allowing the DNOs more time to work together on agreeing a common methodology at EHV level. In our view this option would not guarantee delivery of revised methodologies and would ensure only further delay to the project at EHV level. To our knowledge the critical differences between the FCP and LRIC methodologies are fundamental. A number of proponents of FCP favour the capping of DG charges to zero and are opposed to the nodal cost reflectivity which the LRIC methodology provides. In our work with the DNOs we have seen no evidence to suggest that issues such as these can be overcome in the time available to our satisfaction or without recourse to a higher authority. Since we have decided not to refer the matter to the CC at this stage, we have decided instead that it would be appropriate to allow the DNOs the opportunity to demonstrate the merits of a practical application of their choice of either FCP or LRIC, with the important caveat that they should shoulder the material risk associated with their choice.

2.16. Our proposal is to consult during the summer of 2009 on a special licence condition modification proposal which allows each DNO to choose to implement either the specified LRIC methodology as set out in our October decision or a version of the FCP methodology as developed by the G3 group. Acceptance of the modification would oblige each licensee to implement its choice of EHV methodology by 1 April 2011. We would then have opportunity to observe the performance of each methodology over the remainder of the forthcoming DPCR5 price control review period. Advocates of the FCP methodology do not consider that the use of system charging signals which it generates have the potential to lead to inefficient network investment decisions. In our decision[4] to veto SP's FCP proposal we indicated our disagreement with this view. Under this proposal it is our intention to conduct an ex post review of capex decisions taken during DPCR5. If there is evidence that a DNO's choice of FCP methodology has led to inefficient capital spend we will seek to disallow the recovery of this investment from consumers.

2.17. If our special licence condition modification proposals are successful our decision to allow the DNOs a choice of methodology at EHV level should result in revised charging methodologies being implemented at EHV level by April 2011 without the necessity of referring the matter to the CC. In the event that one or more licensees opt to implement the FCP methodology the option will stop short of delivering full commonality at EHV level across all electricity distribution networks. Nevertheless we would require that those licensees adopting LRIC and those adopting FCP work together to implement the same version of each methodology, and so only two EHV methodologies would apply.

2.18. In our view this provision will ensure that the model for governance arrangements developed as part of the HV/LV common methodology work should be equally applicable to either of the two EHV methodologies and we would expect that consistent with the HV/LV CLM drafting, that any party materially affected by either of the EHV methodologies should have the right to raise a modification proposal to the methodology for consideration and consultation on by the licensee. We consider that open governance arrangements are an important part of ensuring that any unforeseen consequences of implementing either methodology can be addressed at an early stage. We note that the detail behind how EHV level governance will work whilst maintaining two different methodologies needs further consideration.

2.19. Table 2 sets out the revised timeline for the project. In line with responses to our December consultation on next steps we intend to prioritise delivery of HV/LV arrangements for 2010 and therefore the HV/LV CLM is a priority. Further detail on EHV arrangements will follow this to enable delivery of EHV arrangements for April 2011, as set out in the table 2 below.

[4] Decision in relation to SP's proposal to modify its electricity distribution use of system charging model, September 2008, available on our website.

**Table 2 - Indicative timetable for next steps in delivering the structure of charges project**

| Description | Timescale |
|---|---|
| Publish decision on next steps in delivering structure of charges project | 20 March 09 |
| Option of licence drafting working group for HV/LV CLM | 2 April 09 |
| Consult on legal text for HV/LV CLM | April 09 |
| Open statutory consultation on HV/LV CLM proposal | May 09 |
| Licence drafting working group for EHV licence condition | May 09 |
| Consult on legal text for EHV special condition | June 09 |
| Open statutory consultation on EHV special condition | July 09 |
| DNOs submit common HV/LV methodology and governance proposals | 1 September 09 |
| Publish EHV ex-post capex review provision | Final proposals DPCR5 |
| DNOs implement common HV/LV methodology and governance | 1 April 10 |
| DNOs to submit revised EHV methodologies and governance | 1 September 10 |
| DNOs to implement revised EHV methodologies and governance | 1 April 11 |
| Review of EHV methodology impact on investment efficiency | From 2014/15 |

# Appendices

# Appendix 1 - December consultation responses

1.1. In its December consultation document 'Next steps in delivering the electricity distribution structure of charges project' ref 160/08, Ofgem sought the views of respondents about a number of questions as set out below:

Chapter 2: Drivers for the structure of charges project

Question 1: In this chapter we highlight the key objectives for the structure of charges project and explain why these objectives are policy priorities for Ofgem. Do you consider that Ofgem is right to prioritise delivery of these objectives?

Question 2: Given the potential benefits of delivering the project for electricity customers, generators, distributors and suppliers, do you agree that it would be appropriate for Ofgem to continue to pursue delivery of the project?

Chapter 3: Next steps in delivering the structure of charges project

Question 1: Do you consider that it would be appropriate for the Authority to refer the package of measures consulted on in our October proposal for a ruling by the CC? On this question we invite generators, suppliers and customer groups to confirm which aspect of our October decision would deliver the greatest benefit to them, and where possible to quantify this benefit.

Question 2: Do you consider that it would be more appropriate for the Authority to modify the October proposal by excluding the requirement for a common charging methodology at EHV level, and opening a CLM statutory consultation on a modified proposal to deliver commonality at HV/LV level only?

Question 3: If you agree that it would be appropriate to consult again on a modified CLM proposal at HV/LV level, do you consider that it would be appropriate for Ofgem to refer our October decision to implement a common LRIC methodology at EHV level for a ruling by the CC? If you do not agree that it would be appropriate to refer our LRIC decision to the CC, what option would you recommend to Ofgem to deliver revised charging methodologies at EHV level?

Question 4: Are there options we have not considered for ensuring delivery of the structure of charges project, if so what are they?

## List of Respondents

| List | Name |
|---|---|
| 1 | CE Electric |
| 2 | Central Networks |
| 3 | Consumer Focus |
| 4 | DLT Consulting |
| 5 | EDF Energy |
| 6 | Electricity North West |
| 7 | Ener.G Group |
| 8 | E.ON |
| 9 | Haven Power |
| 10 | Mathematical and Computer Modelling |
| 11 | Renewable Energy Association |
| 12 | RWE N power |
| 13 | Scottish Renewables |
| 14 | Scottish Power Energy Wholesale |
| 15 | Scottish Power Energy Retail |
| 16 | Scottish Power Energy Networks |
| 17 | Scottish and Southern Energy |
| 18 | Western Power Distribution |

## Summary of Responses

1.2. We received 18 non-confidential responses to our December consultation. Responses which were not marked as being confidential have been published on our website www.ofgem.gov.uk. Copies of non-confidential responses are also available from Ofgem's library.

1.3. The following is a summary of those responses which were received.

**Chapter Two - Q1 and Q2 - Drivers for the project**

*Respondents' views*

1.4. A large majority of respondents, including DNOs, suppliers and customer representatives supported Ofgem's objectives for the structure of charges project and considered that following the blocking of the October proposal, it was important that we continued to explore ways of delivering the project. One DNO was supportive of the objectives of the project, but queried the way in which we had presented potential network efficiency savings associated with revised charging methodologies at EHV level. One small supplier agreed that delivering the project objectives could deliver network benefits, but considered that insufficient importance was being allocated to considering the impact of charging disturbances associated with the implementation of revised methodologies on small suppliers.  A consumer representative considered that a more thorough quantitative assessment of the benefits of the project should be undertaken before the way ahead is decided.

*Ofgem's view*

1.5. We used chapter two of our December consultation to explain why delivering the structure of charges project continues to be a priority for us and why we consider that the package of measures presented in our October proposal would deliver benefits to electricity users.  The questions we asked in relation to this chapter were designed to gauge whether industry parties agreed with us that the drivers for the project were important and that it was important that the blocking of the October proposal should not allow momentum on the project to dissipate.  From the responses submitted it is apparent that although there may be differences of opinion over the best way to deliver the project, there is a broad consensus across industry that the drivers for the project are valid and that we should continue to pursue delivery of revised charging methodologies on the electricity distribution networks.

1.6. In chapter two of the consultation we set out our view that cost reflective charging methodologies have the potential to reduce the level of network investment required by incentivising customers to connect to areas of the network without capacity constraints and away from network 'hotspots', but we explained that the full extent to which customer behaviour is influenced by charging arrangements is difficult to predict and quantify.  Because investment savings are dependent on hypothetical investment decisions reliably quantifying the impacts of a given methodology is very difficult to do.  We indicated that a 5% reduction of investment at EHV level would equate to efficiency savings of £100-125 million over the forthcoming price control period.  We used this figure to give an indication of the level of investment forecast and the level of benefits which relatively modest efficiency savings could yield.  However it should be acknowledged that network investment is lumpy by nature and the figure was not presented as a forecast.

1.7. The issue of charging stability is also an important consideration for the structure of charges project.  In our view the increased transparency and accessibility that a revised common charging methodology will deliver should increase the predictability of network charges.  In our view this should better enable suppliers to forecast charges, and should allow them to manage customer contracts with greater flexibility.  As indicated in our October document, to allow customers to manage the risks of potential charging volatility, we also set out that it would be appropriate for DNOs to develop longer term charging products after the common charging methodology had been implemented.

**Chapter Three - Q1 - Would it be appropriate to refer the October proposal to the CC?**

*Respondents' views*

1.8. A majority of respondents considered that referring the full project to the CC at this stage would be premature, inappropriate or untimely. A cross section of these respondents considered that a full CC referral would divert industry resources away from the work now being progressed by the CMG towards delivery of a common DRM methodology at HV/LV level.

1.9. Two suppliers, two DNOs and one independent respondent provided qualified support to refer the project to the CC in full. These respondents considered that the amount of time and resources spent on the project to date meant that achieving a landing on the project should be a prioritised, and that referring the matter to the CC would be the most certain way of achieving this. One supplier who backed us to refer the project to the CC did so on the condition that the impact of charging instability on small and medium sized businesses was addressed as a specific issue in the referral. The DNO who supported this option did so because they considered that timely resolution of the project was important but they also expressed reservations that a full CC referral might impact on the progress being made by the DNOs at HV/LV.

1.10. Respondents had mixed views on the question of which aspect of the project they considered to be most important. A majority of large suppliers considered that delivering a common methodology would accrue the greatest benefit. They considered that analysing a single common charging methodology as opposed to seven different charging methodologies would reduce their administrative costs and would better enable them to forecast the level of future charges. Three major suppliers considered that this would allow them to reduce the risk premium they currently levy on charges to help them manage charging volatility. Since suppliers typically pass use of system charges directly on to customers connected at EHV level, it follows that this benefit will principally pertain to charging forecasts at HV/LV level. The opinion of the DNOs was mixed. A number suggested that implementation of cost reflective charging methodologies should be the most important consideration while others considered that implementing methodologies which prioritised the delivery of stable charges to DG was more important. Charging stability was also the priority for a number of customer representative groups, but two respondents with interests in renewable DG considered that it was most important that the revised charging methodology should compensate DG for the benefits they provide to the network in a cost reflective manner.

*Ofgem's view*

1.11. In chapter one of this document we reiterate that we view the structure of charges project as comprising a package of measures which taken together will deliver investment efficiency, sustainability and competition benefits across the distribution networks. Our view is that referring the full package to the CC at this stage would not be the most appropriate way of delivering these benefits. We recognise that the DNOs are taking positive steps towards delivery of a common methodology and governance arrangements at HV/LV level and we consider that it is appropriate that the DNOs efforts are focussed on implementation of this work in time for 1 April 2010. There is a consensus across industry that a full CC referral of the structure of charges project would have the potential to divert the DNOs attention from this work and we are respectful of this view. The reasons for our decision are set out in full in chapter two of this document.

**Chapter Three - Q2 - Would it be appropriate to consult on a CLM proposal to deliver commonality at HV/LV level only?**

*Respondents' views*

1.12. Of those respondents who did not favour full referral of the structure of charges project to the CC with immediate effect, a majority supported the work being progressed by the DNOs towards delivery of a common methodology at HV/LV level, and considered that it was important that everything should be done to ensure timely delivery of this work. A number of large suppliers supported the idea of an HV/LV CLM, but relatively few respondents commented on this proposal directly. Two DNOs commented that they did not think that an HV/LV CLM was necessary, but none of the two indicated that they would register a statutory objection to an HV/LV CLM proposal.

*Ofgem's view*

1.13. We recognise and are fully supportive of the steps that the DNOs have taken since the failure of the October proposal to progress development of a common DRM methodology and governance arrangements at HV/LV level. We consider that implementation of this aspect of our October decision is achievable by 1 April 2010, but consider that it would be remiss of us not to provide the DNOs with a formal licence obligation to deliver the work and so we think that it would be appropriate to consult on an HV/LV CLM to ensure that the obligation is enforceable.

**Chapter Three - Q3 - Would it be appropriate to refer our October decision at EHV level to the CC? If not what other options would you recommend for delivering revised charging methodologies at EHV level?**

*Respondents' views*

1.14. One large supplier and one DNO considered that if we decided to hold an HV/LV CLM to deliver commonality and governance at HV/LV level then it would be appropriate to refer the issue of EHV charging to the CC. Both of these parties considered that the debate over EHV charging had been long running and was unlikely to be resolved without recourse to a higher authority.

1.15. A majority of respondents who supported the work being undertaken by the DNOs towards delivery of a common methodology at HV/LV level did not consider that it would be appropriate to refer the matter of EHV charging to the CC. Not all respondents addressed the issue of resolving EHV charging directly. Some respondents were most concerned that the work at HV/LV should not be disturbed. A number of DNOs suggested that it might be appropriate to allow both the LRIC and the FCP methodology to be implemented at EHV level. One DNO considered that the case in favour of commonality at EHV level had not been demonstrated, and that it would be appropriate to allow the DNOs to develop their own methodologies at EHV level which could be implemented subject to whether the Authority considered they better achieved the relevant objectives of SLC 13. A significant cross section of DNOs, suppliers and customer representatives considered that it would be appropriate to allow the DNOs more time to develop a common charging methodology proposal at EHV level. These respondents considered that if a group of industry experts, consultants and academics were given a specific remit and timeframe for delivering a common EHV charging methodology that it was realistic to expect that a compromise solution could be found to the EHV methodology charging debate.

*Ofgem's view*

1.16. On the basis of our experience of the structure of charges project to date, we do not think that it is likely that the issues associated with EHV charging could easily be resolved without recourse to a higher authority. For this reason we do not support the option of providing the DNOs with more time to propose a common EHV charging methodology among themselves. On the basis that we do not think referring the issue of EHV charging to the CC would be the best use of industry resources at this time, our decision is to allow the DNOs a choice over whether to implement either the LRIC methodology as set out in our October decision, or to implement a version of the FPC methodology as developed by the G3 group. The reasons for this decision are set out in full in chapter two of this document.

**Chapter Three - Q4 - Are there any options for delivering the project that we have not considered?**

*Respondents' views*

1.17. The option of allowing the DNOs a further period of time to propose a common EHV charging methodology and the option of allowing each individual DNO an unrestricted choice of EHV methodology were proposed.

*Ofgem's view*

1.18. We have considered the option of allowing the DNOs a further period of time to propose a common EHV charging methodology. For the reasons set out in chapter two and summarised in paragraph 1.16 of this appendix we do not consider that this option would be a robust way of delivering the structure of charges project. We have also considered the option of allowing the DNOs an unrestricted choice of methodology at EHV level. We have decided to restrict the DNOs choice at EHV level to either LRIC or FCP firstly because to date these are the only two EHV methodologies which we have had the opportunity fully assess, and secondly because we consider that having more than two methodologies will dilute the benefits of commonality and governance arrangements at EHV level.

# Appendix 2 – Indicative licence drafting for HV/LV CLM proposal

## Condition 1. Definitions for the standard licence conditions

### *Relocation of the SLC 13 definition of 'Charging Methodology'*

Transpose existing paragraph 14 of SLC 13 into SLC 1 and place it between 'Charge Restriction Condition' and 'Competition Commission', as follows**:**

**Charging Methodology** means a complete and documented explanation, presented in a coherent and consistent manner, of the methods, principles, and assumptions that apply**:**

(a) in relation to Use of System, for determining the licensee's Use of System Charges; and

(b) in relation to connections, for determining the licensee's Connection Charges,

as approved by the Authority by virtue of the provisions of standard conditions 13, 13A or 50 (as the case may be).

### *Insertion of the definition of 'High and Low Voltage Networks'*

Insert new definition of High and Low Voltage Networks into SLC 1 and place it between 'Grid Code' and 'Holding Company', as follows:

**High and Low Voltage Networks** means where the voltage of the assets on the licensee's Distribution System is less than 22 kilovolts**.**

## Condition 13. Charging Methodologies for Use of System and connection

### *Clarification of relationship between SLC 13 and other conditions*

Add section heading and three new paragraphs to SLC 13 immediately after paragraph 13.13, as follows**:**

#### Arrangements applying because of other conditions

13.14 If the licensee is a Distribution Services Provider, standard condition 50 (Development and implementation of a Common Distribution Charging Methodology) applies in relation to certain obligations of the licensee under this condition 13 with effect from 1 July 2009.

13.15 The Authority may, after consulting all Electricity Distributors, make such consequential modifications of this condition 13 and, so far as is relevant, of standard condition 14 (Charges for Use of System and connection) at such time, in such manner, and to such extent as may be necessary to ensure that, as from 1 April 2010, those provisions properly reflect the effects of the introduction into this licence, on that date, of standard condition 13A (Common Distribution Charging Methodology).

13.16 Modifications made by the Authority under paragraph 13.15 may make different provision for different categories of Electricity Distributor.

# Condition 50. Development and implementation of a Common Distribution Charging Methodology for the High and Low Voltage Networks

**Introduction**

50.1 This condition applies on and after 1 July 2009 for the following purposes.

50.2 The first purpose is to ensure that a Common Distribution Charging Methodology ('CDCM') for calculating Use of System Charges levied on customers connected to the High and Low Voltage Networks is developed and brought into force by the licensee in conjunction with all other Distribution Services Providers on 1 April 2010 ('the Implementation Date') in accordance with the provisions of this condition.

50.3 The second purpose is to provide for the introduction into this licence with effect from the Implementation Date of a transparent compliance and change control framework for the CDCM.

**Part A: Relief from requirements of standard condition 13**

50.4 While this condition is in force in this licence, and except where the Authority directs otherwise, such provisions of standard condition 13 (Charging Methodologies for Use of System and connection) as relate to the licensee's duty to review its Use of System Charging Methodology at least once a year, with a view to modifying it for the purpose of better achieving the Relevant Objectives of that condition, do not have effect for those parts of the Use of System Charging Methodology used for calculating Use of System Charges levied on customers connected to the High and Low Voltage Networks.

**Part B: Common Distribution Charging Methodology**

50.5 The CDCM is a Charging Methodology that**:**

(a) applies for the purpose of ensuring that the Use of System Charges levied on customers connected to the High and Low Voltage Networks by Distribution Services Providers are determined on a common basis, so far as is reasonably practicable; and

(b) has been approved by the Authority on the basis that it achieves the Relevant Objectives set out below.

50.6 The first Relevant Objective is that compliance with the CDCM facilitates the discharge by the licensee of the obligations imposed on it under the Act and by this licence.

50.7 The second Relevant Objective is that compliance with the CDCM facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector.

50.8 The third Relevant Objective is that compliance with the CDCM results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the licensee in its Distribution Business.

50.9 The fourth Relevant Objective is that, so far as is consistent with paragraphs 50.6 to 50.8, the CDCM, so far as is reasonably practicable, properly takes account of developments in the licensee's Distribution Business.

**Part C: Developing a Common Distribution Charging Methodology**

50.10 The licensee must develop the CDCM in compliance with the following requirements.

50.11 The first requirement is that the CDCM must be developed by the licensee in conjunction with every other Distribution Services Provider.

50.12 The second requirement is that the CDCM must be able to be given effect by the licensee by not later than the Implementation Date.

50.13 The third requirement is that the CDCM must conform to such requirements as have been specified by the Authority for the purposes of this condition in a decision given on 1 October 2008 and subsequently clarified and amended on 20 March 2009 with respect to the fundamental principles and assumptions on which the development of the CDCM is to be based.

50.14 The fourth requirement is that the CDCM must be submitted by not later than 1 September 2009 for approval by the Authority.

50.15 The fifth requirement is that a full set of illustrative Use of System Charges that would be likely to result from the licensee's compliance with the CDCM with effect from the Implementation Date, must be submitted to the Authority by not later than 1 September 2009.

50.16 The sixth requirement is that during the development of and before submitting the CDCM pursuant to the fourth requirement, the licensee must have taken all reasonable steps, including where appropriate approaching the Authority to discuss how the licensee proposes to address any unforeseen charging implications of the CDCM, to ensure that the CDCM in the form in which it is being developed, will be capable of being approved by the Authority in accordance with the requirements of Part B of this condition.

**Part D: Approving a Common Distribution Charging Methodology**

50.17 Where the Authority, having regard to its principal objective and duties under the Act, is satisfied with the CDCM developed in accordance with the provisions of Part B and Part C of this condition, it may approve the CDCM. In issuing an approval the Authority must:

(a) set out the Authority's reasons for approving it; and

(b) specify the date (being not later than 31 December 2009 unless otherwise directed by the Authority) on which it proposes that the approval should have effect.

50.18 Subject to paragraph 50.19, an approval by the Authority under paragraph 50.17 may be granted subject to such conditions as the Authority considers appropriate, having regard, in particular, to**:**

(a) the need for any further action to be undertaken by the licensee to ensure that the Charging Methodology would better achieve the Relevant Objectives; and

(b) the time by which such action must be completed.

50.19 No condition imposed under paragraph 50.18 is effective unless, before granting the relevant approval, the Authority has informed the licensee of its intention to impose the condition in a Notice which**:**

(a) sets out the nature and contents of the condition; and

(b) specifies a period of at least 28 days within which representations or objections with respect to the condition may be made,

and has considered any representations or objections that are duly made by the licensee and not withdrawn.

50.20 Except that the Authority may not bring forward the dates specified in Parts D, E, F, G and Appendix 1 of this condition, the Authority may direct that such deadlines as are specified in those Parts of that Appendix may be amended as the Authority considers necessary for the purpose of meeting its wider public law duties or having regard to its principal objective and duties under the Act.

**Part E: Implementing a Common Distribution Charging Methodology**

50.21 Where the Authority has approved the CDCM under Part D of this condition, the licensee must, with effect from the Implementation Date**:**

(a) revoke those parts of its Use of System Charging Methodology used for the calculation of use of system charges levied on customers connected to the High and Low Voltage Networks, in the form in which it is in force under standard condition 13 at 31 March 2010; and

(b) implement the CDCM immediately thereafter from 1 April 2010 in the form in which it has been approved by the Authority.

**Part F: Arrangements for handling modification proposals**

50.22 Arrangements for handling modification proposals to the CDCM (‘modification arrangements’) must be developed by the licensee in conjunction with all other Distribution Services Providers, and in consultation with other

Authorised Electricity Operators, and must be submitted for approval to the Authority not later than 1 September 2009.

50.23 Modification arrangements must include provision for the following core features.

50.24 The first core feature is that the arrangements must provide for the licensee to meet periodically with other Distribution Service Providers, other Authorised Electricity Operators and any other persons whose interests are materially affected by the CDCM for the purpose of discussing the further development of the CDCM.

50.25 The second core feature is that the arrangements must provide for a timely and efficient process by which the licensee can:

(a) formally receive modification proposals;

(b) consult on the merits of those proposals with other Distribution Service Providers, other Authorised Electricity Operators, and any other persons whose interests are materially affected by the CDCM; and

(c) evaluate those proposals in the light of that consultation.

50.26 The third core feature is that the arrangements must provide for the licensee to have a report on any modification proposal prepared in a timely and efficient manner for submission to the Authority that:

(a) sets out the terms proposed for the modification;

(b) fairly summarises the representations received during the consultation process under paragraph 50.25;

(c) sets out the conclusions reached by the licensee and other Distribution Services Providers about the modification proposal in question, including whether the modification would better achieve the Relevant Objectives; and

(d) sets out a timetable for implementing the modification, if it were to be made, and the date with effect from which the modification (if made) would take effect.

50.27 The fourth core feature is that the arrangements must provide for the review and future modification (where appropriate) of the modification arrangements.

**Part G: Approval of arrangements for handling modifications**

50.28 Where the Authority, having regard to its principal objective and duties under the Act, is satisfied that the modification arrangements submitted under paragraph 50.22 of this condition comply with the features set out in paragraphs 50.24 to 50.27, it may approve those arrangements as the modification arrangements approved by the Authority for the purposes of standard condition 13A (Common Distribution Charging Methodology). In issuing an approval the Authority shall:

(a) set out the text of the modification arrangements and the Authority's reasons for approving them; and

(b) specify the date on which it proposes that the approval should have effect.

50.29 Subject to paragraph 50.30, an approval by the Authority under paragraph 50.28 may be granted subject to such conditions as the Authority considers appropriate, having regard, in particular, to:

(a) the need for any further action to be undertaken by the licensee to ensure that the modification arrangements would better meet the features set out in paragraphs 50.24 to 50.27 of this condition; and

(b) the time by which such action must be completed.

50.30 No condition imposed under paragraph 50.29 is effective unless, before granting the relevant approval, the Authority has informed the licensee of its intention to impose the condition in a Notice which:

(a) sets out the nature and contents of the condition; and

(b) specifies a period of at least 28 days within which representations or objections with respect to the condition may be made,

and has considered any representations or objections that are duly made by the licensee and not withdrawn.

**Part H: Compliance and change control framework**

50.31 Where the Authority has approved the CDCM under Part D of this condition, this Part H applies on the Implementation Date for the purpose of modifying the standard conditions of this licence with effect from that date in accordance with paragraph 50.32 below.

50.32 The modification referred to in paragraph 50.31 is that standard condition 13A in the form set out at Appendix 1 (which is part of this condition 50) comes into force in this licence on the Implementation Date.

**Part I: Interpretation and termination**

50.33 For the purposes of this condition, the CDCM achieves the Relevant Objectives if it achieves them in the round, taking one objective with another.

50.34 Unless and to the extent otherwise directed by the Authority, this condition is of no further effect in this licence after the Implementation Date.

50.35 Appendix 1 follows immediately below.

**Part J: Derogations**

50.36 The Authority may (after consulting the licensee and, where appropriate, any other Authorised Electricity Operator likely to be materially affected) give a direction ('a derogation') to the licensee that varies or relieves it of its obligations under Part C of this condition in respect of such elements of the CDCM, to such extent, for such period of time, and subject to such conditions as may be specified in the direction.

# APPENDIX 1

## Condition 13A. Common Distribution Charging Methodology for the High and Low Voltage Networks

**Part A: Licensee's obligations**

13A.1 This condition applies to the licensee on and after 1 April 2010 if the licensee is a Distribution Services Provider.

13A.2 The licensee must take all steps within its power to ensure that the Common Distribution Charging Methodology ('CDCM') for the High and Low Voltage Networks in force under this licence at 1 April 2010 continues to be a Charging Methodology for the determination of the licensee's Use of System Charges that is approved by the Authority on the basis that it achieves the Relevant Objectives set out in Part B below.

13A.3 The licensee must at all times implement and comply with the CDCM.

13A.4 The licensee must, for the purpose of ensuring that the CDCM continues to achieve the Relevant Objectives**:**

(a) review the methodology at least once every year; and

(b) subject to Part C of this condition, make such modifications (if any) of the methodology as are necessary for the purpose of better achieving the Relevant Objectives.

**Part B: The Relevant Objectives of the CDCM**

13A.5 The Relevant Objectives that the CDCM must achieve are as follows.

13A.6 The first Relevant Objective is that compliance with the CDCM facilitates the discharge by the licensee of the obligations imposed on it under the Act and by this licence.

13A.7 The second Relevant Objective is that compliance with the CDCM facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector.

13A.8 The third Relevant Objective is that compliance with the CDCM results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the licensee in its Distribution Business.

13A.9 The fourth Relevant Objective is that, so far as is consistent with paragraphs 13A.6 to 13A.8, the CDCM, so far as is reasonably practicable, should properly take account of developments in the licensee's Distribution Business.

13A.10 For the purposes of this condition, the CDCM achieves the Relevant Objectives if it achieves them in the round, taking one objective with another.

**Part C: Procedure for modifying the CDCM**

13A.11 Proposals for modifying the CDCM (‘modification proposals’)**:**

(a) may be raised by any Authorised Electricity Operator; or

(b) any other person whose interests are materially affected by the CDCM; and

(c) must be handled by the licensee in conjunction with all other Distribution Services Providers and in accordance with the relevant modification arrangements.

13A.12 The relevant modification arrangements are the modification arrangements approved by the Authority for the purposes of this condition 13A and in force under this licence at 1 April 2010 by virtue of the provisions of standard condition 50 (Development and implementation of a Common Distribution Charging Methodology), as modified from time to time in such manner as is provided for by those arrangements.

13A.13 Unless otherwise directed by the Authority under paragraph 13A.14, before making a modification to the CDCM the licensee must have a report prepared for submission to the Authority that**:**

(a) sets out the terms proposed for the modification;

(b) fairly summarises the representation received during the consultation process on the modification proposal;

(c) sets out the conclusions reached by the licensee about the modification proposal in question, including whether the modification would better achieve the Relevant Objectives; and

(d) sets out a timetable for implementing the modification and the date with effect from which the modification (if made) is to take effect (which must not be a date earlier than the date on which the period referred to in paragraph 13A.16 will end)

13A.14 If the Authority has directed that paragraph 13A.13 should not apply, the licensee must comply with such other requirements (if any) as the Authority may specify in its direction.

13A.15 Subject to paragraph 13A.16, where the licensee has complied with the requirements of paragraph 13A.13 the licensee must, before making the modification**:**

(a) revise the relevant statement of the CDCM (or the most recent version of that statement) published in accordance with paragraph 13A.17 so that it sets out the changed methodology and specifies the date from which that is to have effect; and

(b) give the Authority a copy of the revised statement.

13A.16 The licensee must make the modification of the CDCM unless, within 28 days of receiving the licensee's report under paragraph 13A.13, the Authority has either**:**

(a) directed the licensee not to make the modification; or

(b) notified the licensee that it intends to consult and then within three months of giving that notification has directed the licensee not to make the modification.

**Part D: Public availability of the CDCM**

13A.17 The licensee must ensure that a copy of the CDCM that is in force under this condition, as from time to time modified, is publicly available on the licensee's website, if it has one, and is otherwise available to any person who requests it upon payment of an amount not exceeding the reasonable costs of making and supplying that copy.

**Part E: Derogations**

13A.19 The Authority may (after consulting the licensee and, where appropriate, any other Authorised Electricity Operator likely to be materially affected) give a direction ('a derogation') to the licensee that varies or relieves it of its obligations under Part A of this condition in respect of such elements of the CDCM, to such extent, for such period of time, and subject to such conditions as may be specified in the direction.

# Appendix 3 – Principles and assumptions for the implementation of a common DRM at HV/LV level

1.1. This Appendix provides the principles and assumptions for the implementation of the DRM at HV and LV levels. The principles and assumptions are replicated verbatim from Appendix 2 of our October proposals. For ease of reference the paragraph numbering below reflects the numbering in our October proposals. Amendments at HV/LV levels that reflect our proposal to allow DNOs to implement either the LRIC methodology specified in our October 2008 decision or a version of the FCP methodology at EHV level, as well as the ongoing work of the CMG and its work streams toward a common HV/LV DRM methodology are contained in Appendix 4.

### Interaction between LRIC and DRM

1.28. A LRIC methodology applies at EHV and a DRM methodology at HV/LV. There is a relationship between these two methodologies as HV/LV customers place demands on the EHV network. In order to ensure that this impact is captured within charges, certain aspects of the LRIC charge are passed into the DRM yardstick. Costs for voltage levels 132kV down to 33kV/11kV substation from the LRIC model are dropped into the DRM at the 33kV/11kV transformation level. The interaction works as follows:

- The residual value is calculated by taking the target income of EHV assets (total revenue split by the proportion which the EHV MEAV comprises of the total network MEAV). The total amount recovered from EHV customers is then subtracted from this amount.
- The remaining cost to be recovered on the EHV network (the residual value) is then divided by the difference between the total EHV customer KVA and total EHV kVA to give a £/kVA value which represents what the HV/LV network should pay for its use of the EHV system.
- The £/kVA value is then divided by the assumed DRM power factor of 0.95 to provide a £/kW value.
- The £/kW value is then placed into the 33kV/11kV transformation level within the DRM yardstick.

## HV/LV demand charging

### DRM

1.29. Charges for HV/LV demand will be calculated using a distribution reinforcement model (DRM).

1.30. A representative network which comprises of the assets required to accommodate a 500 MW increment to each distribution service area (DSA) is developed as a scenario. This is based on the topography and demographics of the expected network and how this network is likely to develop over time. This representative network excludes what would be paid for in connection charges under the current charging regime. For example the LV service cable is excluded from the representative network to the extent that they are covered by connection charges. Replacement costs should not be included within this representative network. These costs are captured as part of price control revenue and therefore the scaling element of the charge should fund replacement of assets.

1.31. The network costs (calculated in terms of their modern equivalent asset value (MEAV)) of accommodating this incremental network is calculated for each of the following transformation and voltage levels[5]:

- HV circuits
- 11kV/LV Substations
- LV circuits

1.32. This produces a cost at each transformation at each of the voltage levels noted above. This cost is then allocated to the following minimum number of customer classes[6]:

- NHH Domestic Unrestricted (PC1)
- NHH Domestic Restricted (PC2)
- NHH Non Domestic Unrestricted (PC3)
- NHH Non Domestic Restricted (PC4)
- NHH Unmetered Supplies (PC 1-8)
- NHH LV (PC5-8)
- HH LV
- HH HV

1.33. This allocation is calculated by looking at the average consumption of an individual customer in each customer class. This average is then multiplied by the number of customers in each customer class to provide the overall annual consumption (or load) of the entire customer class at the voltage level of connection.

1.34. Loss adjustment factors are used to scale up the load at the voltage of connection to the load which is placed on the transformation levels and voltage levels above the voltage of connection.

1.35. Coincidence factors are then used to assess the contribution each customer class comprises to overall network peak demand. Finally the entire sum is divided by the load factor of the network.

[5] Please note that for EHV voltage and transformation levels the costs which HV/LV users place on the EHV network are calculated within the LRIC methodology. The incremental costs from the EHV assets which HV/LV users utilise are fed down into HV/LV charges. The precise mechanics of this approach are described in detail above.
[6] We would expect any charging methodology to include these customer classes but *the precise details are subject to development, for example IDNO tariffs*.

1.36. These series of calculations are shown by mathematical formula below:

$$CustomerclassSystemMaxDemand(kW) = \frac{1000 \times AnnualConsumption(MWh) \times CoincidenceFactor \times [1 + Losses]}{Loadfactor}$$

1.37. These calculations are repeated to produce a peak system demand at each voltage and transformation level for each customer class.

1.38. The network costs at each voltage and transformation level are then associated with the addition of the 500 MW increment are then split by the proportion which each customer class contributes to the peak network demand.

1.39. These costs are then annuitized over a 40-year period using the DPCR cost of capital. This produces a yardstick unit cost in p/kWh.

1.40. In order to calculate the contribution of each customer class to the peak network maximum demand, the following data is required:

- Forecast units distributed or consumption (MWh);
- Forecast agreed capacities (kVA);
- Forecast customer numbers;
- Load factors (kWh/year/kW) – this is the forecast annual consumption for the customer group divided by the maximum demand;
- Coincidence factors – this is the ratio of the maximum demand at the time of system peak divided by the customer group's maximum demand;
- Loss percentage – this is a calculated value based on published loss factors for each half-hour and the actual consumption in that half-hour; and
- Power factor – a value of 0.95 is used for all loads to convert from kW to kVA.

1.41. This data is updated (i.e. the new, latest forecast inputs used) each time a distributor updates its charges.

1.42. Operational and Maintenance (O&M) costs are also included within the DRM. The rate for O&M is calculated as a percentage based on forecast O&M costs and are calculated for the next charging year. These costs are then calculated as a % of the total MEAV asset cost. As with the calculation of network costs the DRM looks at the contribution each customer class makes to peak network demand. This provides a proxy as to the assets which each customer class uses. The ratio of which O&M costs comprise of total cost is then applied to the assets each customer class uses. This provides a cost figure for each voltage and transformation level. As with the network costs, these are then split into yardsticks by looking at the contribution each customer class makes to peak network demand at each voltage level. Again once these costs have been allocated, they are annuitized over 40 years.

1.43. The yardstick costs produced are then allocated to both the unit charge (p/kWh) and the fixed charge (p/MPAN/day). The precise method in which this allocation works will be made clear in the common spreadsheet charging templates which Ofgem are committed to help DNOs develop.

1.44. This calculation produces a £/kW/year charge. This is divided by an assumed power factor of 0.95 in order to produce a £/kVA/year charge.

*The split between day and night charges and the calculation of capacity charges must also be determined and we consider that this detail will be included in the final template which Ofgem is committed to developing alongside DNOs.*

*The form of the final charge (including common tariff structures) is to be further developed by distributors, incorporating a reactive power charge for customers with a power factor worse than 0.95.*

1.45. Excess reactive power charges are levied for those customers with a power factor of less than 0.95. The charges are derived from the same network yardstick costs used for other DUoS components.

1.46. For each customer class (at the respective voltage level), an excess reactive unit charge may be derived from the incremental change in the yardstick[7] (for a defined change in power factor) divided by the incremental change in the kVAr (for the same change in power factor), adjusted by the customer class load factor to give the cost of an additional reactive unit (in pence/kVArh).

1.47. For clarity this calculation is described below in six steps. The first three steps derive the costs of delivering a kWh at different power factors. The following three steps focus on the incremental effects of varying power factor, in terms of cost and unit volume, in order to derive prices. For each customer class at the respective voltage level:

i. Calculate the yardstick excluding the fraction used in the availability charge calculation (in £/kWpa), recognising that this assumes a power factor of 0.95.

ii. Convert this to pence/kWh by dividing by the kWh/kW pa for the customer class and multiplying by one hundred.

iii. For the range of power factors from 0.95 through to 0.05 (in increments of 0.05), derive the “adjusted pence/kWh” by multiplying the “yardstick pence/kWh” (calculated in step two above) by the ratio of 0.95 (the network design power factor) to the new power factor.

[7] The yardstick value used in the reactive power methodology excludes the element of the yardstick used in the calculation of the availability charge.

iv. Derive, from the table produced in step three above, the incremental cost, in pence/kWh, of moving to each of the tabulated power factors, thereby defining power factor bands.

v. Calculate, and tabulate, the incremental change in reactive units per kWh (kVArh/kWh) for the same range of power factors bands.

vi. Divide the incremental cost effect (shown in step four above) by the incremental reactive units (shown in step five above) to provide the excess reactive unit charge (in pence/kVArh) for each power factor band.

**Scaling**

1.48. Scaling is required to align the total yardstick charges with allowed revenue from price control. A fixed adder should be used to scale up the revenue recovered through charges to allowed revenue. At a high level this works by splitting total revenue by the MEAV of the HV/LV assets to obtain a target recovery for HV/LV. The difference between the allowed revenue and recovered revenue is then allocated to customers on a kWh or p/MPAN basis.

Detail of fixed adder application to be further worked up by DNOs. Again, note interaction with generation side.

## HV/LV Generation

*Note that generator use of system charging for "existing" (i.e. pre-April 2005) generators is being taken forward under the price control review.*

1.49. The charges allocated to generators are applied using the same principles as those used for demand tariffs. Where HV/LV demand incremental costs are offset or deferred the charge will be negative pre scaling. Generators are also liable for use of system charges on their demand requirements.

1.50 Charges for generators connecting at HV or LV will be calculated in accordance with the assumption that generators provide benefits in deferred investment and this should be reflected in the charges.

1.51 The network is assumed to be demand dominated. Credit will be provided for offsetting demand on the distribution network above the voltage of connection.

1.52. The calculation of the charges for HV/LV generation that exports onto the distribution system is explained [above] in accordance with demand charges. The DRM methodology defines the costs incurred or credited to exporting HV and LV distributed generation.

1.53. It is assumed that the generator will not cause additional reinforcement costs as there will be even dispersion of generation across the network. A generator will offset demand and provide benefits to higher voltage levels by delaying reinforcement. To reflect the benefits a generator provides, a negative sign will be applied to the yardsticks when calculating the generator charges.

1.54. The level of the charge will be determined in accordance with universal P2/6 security standards (F-Factors). Where a generator is defined to be a non-intermittent type of generation, the generator will be assigned an F-Factor based on its generator type and number of units in the generating station that determines the impact of generation on the distribution network. Where a generator is defined to be an intermittent type of generation, the generator will be assigned an F-Factor based on the period of continuous generation (i.e. Persistance) and not affected by the number of units at an individual site.

1.55. The values for the generator F-Factors will be sourced from tables 2-1 and 2-2 of Engineering Recommendation P2/6. These will be applied to all HV/LV generation irrespective of P2/6 thresholds.

1.56. The P2/6 security factor (F-Factor) will be multiplied by the calculated yardstick from the DRM and multiplied by -1 to provide a negative charge. The negative charge reflects the positive impact generation has on the network at this level.

1.57. Generator charges will be calculated using the following formula:

$$GDUoS = DRMYardstick * FFactor * (-1)$$

F factors need to be specified in the charging methodology for each technology, along with detail provided on how F factors apply at LV.

Format of Charges

*The detail of tariff structures is to be developed by DNOs.*

Scaling

1.58. In order to match HV/LV generator charges to allowed revenue, the yardsticks will be subject to scaling. A fixed adder method will be applied to HV/LV generator charges as per all other charges in the DRM model.

*Detail of scaling to be developed by DNOs: fixed adder approach, further detail to be worked up. Note the interactions with the price control review and associated special licence conditions.*

**4. IDNO charging**

*IDNO charging is to be developed by DNOs working with IDNOs.*

# Appendix 4 – Amendments and clarifications to the principles and assumptions for the implementation of a common DRM at HV/LV level

1.1. The amendments to Appendix 2 to our October 2008 proposals given below reflect deviations that result both from our proposal to split the project between delivery at HV/LV level and delivery at EHV level, as well as from the ongoing work of the CMG and its work streams[8] towards a common DRM methodology.

## Amendments that follow the decision to allow DNOs to choose between a common LRIC and a common version of FCP at EHV level

1.2. The following should replace paragraph 1.28. from Appendix 2 to our October proposals document:

**Interaction between EHV and HV/LV charging model**

There is a relationship between the charging methodology which applies at EHV and the DRM methodology which applies at HV/LV. HV/LV customers place demands on the EHV network, and in order to ensure that this impact is captured within charges, certain aspects of the EHV charge are passed into the DRM yardstick. Costs for voltage levels 132kV down to 33kV/11kV substation from the EHV model are dropped into the DRM at the 33kV/11kV transformation level. The interaction works as follows:

- EHV network costs to be recovered from HV/LV customers are based on the residual value of target EHV income after the amount of revenue recovered from EHV customers is deducted.
- The residual value is calculated by taking the target income of EHV assets (total allowed revenue split by the proportion which the EHV MEAV comprises of the total network MEAV). The total amount of revenue recovered from EHV customers is then subtracted from this amount.
- The remaining cost to be recovered on the EHV network (the residual value) is then divided by the difference between the total EHV customer KVA and total EHV kVA to give a £/kVA value which represents what the HV/LV network should pay for its use of the EHV system.
- The £/kVA value is then divided by the assumed DRM power factor of 0.95 to provide a £/kW value.

[8] See http://2009.energynetworks.org/structure-of-charges/.

- The £/kW value is then placed into the 33kV/11kV transformation level within the DRM yardstick.

## Clarifications and amendments that follow from the ongoing work of the Common Methodology Group and its work streams towards a common DRM methodology

- The last sentence of Paragraph 1.42 should be omitted.
- In Paragraph 1.48 and Paragraph 1.58, the reconciliation of yardstick charges with allowed revenue refers to the reconciliation of the combined yardstick charges of demand and generation with a single regulatory pot of allowed revenue as will be provided under DPCR5. *The detail of how this revenue pot will be applied demand and generation is to be developed by the DNOs.*
- Paragraphs 1.50-1.57 only apply to demand dominated networks.
- Paragraphs 1.54-1.57 describe how to use Engineering Recommendation P2/6 and its F-Factors toward calculating credits to generators. We are aware that the DNOs have advocated a method that relies on units distributed rather than F-Factors and we recognise the merits of their approach.
- The number 4 in front of the title 'IDNO charging' should be deleted and the title should be in large blue font.

# Appendix 5 – The Authority's powers and duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts[9].

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[10].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- the need to secure that all reasonable demands for electricity are met;
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them[11];
- the need to contribute to the achievement of sustainable development; and
- the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas[12].

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

[9] entitled "Gas Supply" and "Electricity Supply" respectively.
[10] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[11] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[12] The Authority may have regard to other descriptions of consumers.

- promote efficiency and economy on the part of those licensed[13] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and
- secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- the effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[14] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[13] or persons authorised by exemptions to carry on any activity.
[14] Council Regulation (EC) 1/2003.

# Appendix 6 - Glossary

**A**

### Authority

The Authority is the governing body for Ofgem, consisting of non-executive and executive members.

**C**

### Competition Act 1998

The Competition Act 1998 (CA98) gives the Office of Fair Trading and the sector regulators, powers to apply and enforce Articles 81 and 82 of the EC Treaty as well as the Chapter I and II prohibitions of CA98 using their concurrent powers. Article 81 and the Chapter I prohibition prohibit agreements which have the object or effect of preventing, restricting or distorting competition. Article 82 and the Chapter II prohibition prohibit conduct by one or more undertakings which amounts to the abuse of a dominant position in the market.

**D**

### DG - Distributed Generation

Generation which is connected directly into the local distribution network as opposed to the transmission network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transmitted for use across the UK.

### DNOs - Distribution Network Operators

A licensed distributor which operates electricity distribution networks in its designated distribution service areas.

### DPCR5 - Distribution Price Control Review 5

DNOs operate under a price control regime, which are intended to ensure DNOs can, through efficient operation, earn a fair return after capital and operating costs while limiting costs passed onto customers. Each price control typically lasts five years at a time. The existing price control will expire 31 March 2010. DPCR5 is the fifth review of the price control and commenced in early 2008. The resulting price control is planned to commence 1 April 2010.

**E**

### Electricity Act 1989

Electricity Act 1989 c.29 as amended. Also referred to as ‘The Act’.

### EHV - Extra High Voltage

Term used to describe the parts of distribution networks that are extra high voltage.

**H**

HV - High Voltage
Term used to describe the parts of distribution networks that are high voltage.

**I**

IDNOs - Independent Distribution Network Operators
A licensed distributor which does not have a distribution services area and competes to operate electricity distribution networks anywhere within the UK.

**L**

LV - Lower Voltage
Term used to describe the parts of distribution networks that are lower voltage.

**P**

Engineering Recommendation P2/6
A guide for electricity distribution network system planning and security of supply. It is a revision of Engineering Recommendation P2/5 issued in 1978, which it supersedes.

**S**

SLC - Standard Licence Condition
These are conditions that licensees must comply with as part of their licences. SLCs can only be modified in accordance with Section 11A of the Electricity Act. Failure to comply with SLCs can result in financial penalties and/or enforcement orders to ensure compliance.

**U**

UoS Charges
Use of System Charges: Charges paid by generators and suppliers for the use of the distribution network.

## Appendix 7 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

- Does the report adequately reflect your views? If not, why not?
- Does the report offer a clear explanation as to why not all the views offered had been taken forward?
- Did the report offer a clear explanation and justification for the decision? If not, how could this information have been better presented?
- Do you have any comments about the overall tone and content of the report?
- Was the report easy to read and understand, could it have been better written?
- Please add any further comments?

1.2. Please send your comments to:

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