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Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements

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

Overview:

This document sets out our decision on the common methodology and governance arrangements that should apply to electricity distribution use of system charges across GB. We set out our decision on the governance arrangements to apply to the highest voltage levels from April 2011. This document also sets out our decision on the two charging models to be applied at the highest voltage levels from April 2011. In parallel we are publishing a statutory notice of the licence modifications required to implement the new arrangements. Electricity distribution licence holders have until 4 September to decide whether or not to accept these proposed licence modifications.

Common charging arrangements at the lower voltage levels are being developed by the electricity distribution network companies who have a licence requirement to deliver this along with their proposals for common governance arrangements at lower voltages for 1 September 2009, to apply from April 2010.

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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 and it is important that charging arrangements evolve to reflect these changes. 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 extent of this investment, and the significant increase in energy prices in recent years, it is important we do all we can to have charging arrangements that encourage customers to locate where there is spare capacity. Cost reflective charges will also encourage more local, low carbon generation to connect closer to demand at distribution level and will help make sure the 10GW of distributed generation forecast to connect to the distribution networks between 2010 and 2015 is rewarded where they provide network benefits.

On 1 July 2009 we introduced a licence obligation on DNOs to implement a common methodology and open governance arrangements at lower voltage levels on the distribution networks for 1 April 2010. Today we have published licence proposals obliging the DNOs to implement revised charging at the extra high voltage levels for 1 April 2011. We have also published a decision on the governance arrangements applying to the new methodologies which will ensure that the benefits of commonality are preserved, and will ensure that 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. If they are successful, the licence proposals published today will complete the package of DNO licence obligations that we signalled would be necessary to deliver the structure of charges project in March of this year.

Associated Documents

- Collective Licence Modification intended to deliver the electricity distribution structure of charges project at lower voltages, 48/09, May 2009
- Next steps in delivering the electricity distribution structure of charges project: decision document, 24/09, March 2009
- 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

Table of Contents

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 (particularly large) users to consider the costs imposed on the network when they are deciding where to locate and how to use the network. Cost reflective charges are also required to reward users who provide a benefit to the distribution network, for example distributed generation (DG) located close to load or customers implementing demand side management, and to properly reflect the costs that independent network operators (IDNOs) place on the system. We also think there would be significant benefits from all DNOs applying common charging arrangements, 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. In addition open governance arrangements will help to ensure that charging methodologies evolve in response to changes in network use and that the views of all parties can be considered as the methodologies are modified.

Since the beginning of 2008 we have been working to place licence obligations on the DNOs so that we could be sure the project objectives would be delivered by April 2010, in line with the start of the next five-year price control period. As part of this work we have consulted on, assessed the impact of and developed proposals for a common set of charging and governance arrangements across DNOs.
For the lower voltage levels, we introduced a collective licence modification (CLM) on 1 July 2009 which required the DNOs to bring forward common charging arrangements at the lower voltage levels by 1 September 2009 which would take effect from 1 April 2010 along with associated open governance arrangements. Since October 2008 the DNOs have been progressing common charging arrangements at lower voltage levels for implementation in April 2010 initially voluntarily and then under the CLM. We have been engaging in their work and we understand that they are on track to submit the common methodology to us on 1 September.

The industry is divided on the best methodology for extra high voltage charging, and in October 2008 our CLM proposal to implement a common long run incremental cost (LRIC) methodology for higher voltage charging was blocked. Rather than risk delaying implementation by referring the matter to the Competition Commission, we have decided to require each DNO to choose whether to develop a common LRIC model or a common version of the forward cost pricing (FCP) approach developed by the G3[1] group for implementation by 1 April 2011. This document provides more detail on our EHV charging decision, sets out the key areas for future development, and, as part of the general review of investment in the following price control review (DPCR6), confirms our intention to scrutinise the investment decisions of those DNOs choosing to implement the common FCP methodology to ensure that it has not led to inefficient capital expenditure.

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

The DNOs are also required to submit proposals to us for handling modification arrangements to the common methodology for the lower voltage levels by 1 September 2009. The licence obligations require DNOs to develop proposals which provide for, among other things, the ability of any materially affected parties to be consulted on and to raise modification proposals concerning the common methodology.

The DNOs submitted their governance proposals to us on 15 July 2009 and their key recommendation is that the new common charging methodologies (at both the lower and extra high voltage levels) should be incorporated into the Distribution and Connection Use of System Agreement (DCUSA) and be subjected to the governance and change control mechanisms of the DCUSA code. We have reached the view that the DNOs' proposal would be compatible with the governance obligations specified in the licence. This document explains the reasons for our decision and sets out the steps we intend to take prior to publishing a formal direction on the DNOs' proposals.

In parallel to the publication of this decision, we have published today a statutory consultation on the collective licence modifications necessary to oblige the DNOs to implement revised EHV charging, and the modifications necessary to provide for the formal incorporation of the common methodologies within the DCUSA from the time of their implementation. The statutory consultation on the CLM proposals closes on 4 September 2009.

1. Electricity distribution structure of charges project update

Chapter Summary

In this chapter we set out the context for the decisions contained in this document and the background to our recent work on the electricity distribution use of system charging methodologies. We also explain the structure of the remainder of this document.

Progress on the structure of charges project

Publication of March decision

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 bring forward a common distribution charging methodology and common governance arrangements for implementation by 1 April 2010. The October proposal was supported by a majority of DNOs, but it was blocked as a result of the statutory objections registered by two DNOs holding four distribution licences, both of whom disagreed with our decision to require DNOs to apply a Long Run Incremental Cost (LRIC) methodology as the foundation for Extra High Voltage (EHV) charging.

1.2. Following consultation in December 2008[2], in March 2009 we published a decision document on next steps for the structure of charges project[3]. In this document we decided that it would be appropriate to split the structure of charges project between delivery at the high voltage and low voltage (HV/LV) levels and delivery at the extra high voltage (EHV) levels on the distribution networks. For the HV/LV network we decided that it would be appropriate for the DNOs to implement a common charging methodology and governance arrangements for implementation by April 2010. For EHV charging we decided that it would be appropriate for the DNOs to implement their choice of one of two common charging methodologies: a common LRIC model or a common version of the forward cost pricing (FCP) approach developed by the G3[4] group. To allow the DNOs to prioritise delivery of a common HV/LV methodology by 2010, we decided to require DNOs to implement a revised methodology and governance arrangements for EHV charges by April 2011.

May HV/LV CLM proposal

1.3. Consistent with our March decision, on 8 May 2009 we consulted on a CLM proposal putting in place a licence obligation on the DNOs to deliver the common

[2] Next steps in delivering the electricity distribution structure of charges project: consultation document, 160/08, December 2008.
[3] Next steps in delivering the electricity distribution structure of charges project: decision document, 24/09, March 2009.
[4] The G3 group comprised Central Networks, Scottish Power and Scottish and Southern Energy.

charging methodology and governance arrangements at the lower voltage levels for implementation with effect from 1 April 2010. No statutory objections to the proposal were received and the CLM became effective on 1 July 2009.

1.4. The DNOs have been working together under the auspices of the Common Methodology Group (CMG) to progress development of the common HV/LV charging methodology consistent with our October decision. Ofgem has worked with the CMG since the beginning of 2009 and has provided feedback and guidance on issues relating to the development of the HV/LV common methodology. The licence requires the DNOs to bring a common HV/LV charging methodology and governance proposals to Ofgem for approval by 1 September 2009. The steps taken by the DNOs at the end of last year in setting up the CMG at an early stage have been instrumental in making these deadlines achievable.

1.5. More than 99 per cent of distribution customers are connected to the lower voltage networks and achieving a common methodology and governance arrangements at HV/LV level will deliver a significant part of the benefit industry and large suppliers associate with the project. Responses to our December consultation on next steps indicated a consensus across industry (particularly among suppliers and generators) that delivering a common methodology and governance at the lower voltage levels will bring network benefits to HV/LV connected distributed generation (DG) and potentially significant efficiency benefits to suppliers in terms of reduced charging risk premia and reduced administration costs. The level of support across the industry in favour of a common HV/LV methodology helped persuade us that it was right to prioritise delivery of this part of the project for April 2010.

Delivering EHV charging

1.6. From a network investment point of view, delivering revised EHV charging remains a key part of the structure of charges project. 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 where significant new loads have potentially greater flexibility over where they locate. Investment and operational decisions taken here have potential to impact on the level of network charges faced by all distribution customers and so we think it is important to encourage cost reflective charging at this voltage. We reached the decision in March that implementing revised EHV charging and governance arrangements for April 2010 may not be practical, but we are convinced that it is appropriate to ensure delivery by April 2011. It is for this reason that in parallel to the publication of this document, we have published today a statutory notice of the licence modifications necessary to oblige the DNOs to implement revised EHV charging and governance arrangements by April 2011.

1.7. In our March document we indicated our preference to deliver EHV charging by consulting on individual licence modification proposals for each DNO, but given the ongoing collaborative nature of the proposed EHV obligations we have now decided to consult on the necessary licence changes by way of a section 11A CLM proposal.

In drafting the CLM proposal we have replicated the structure of the HV/LV CLM that came into effect on 1 July 2009, but consistent with our March decision we require the DNOs to choose to either work with other DNOs towards implementation of a common LRIC methodology or work with other DNOs towards implementation of a common FCP methodology. If the CLM is successful the new licence obligation will come into effect on 1 October 2009 and each DNO will be required to submit either a common LRIC or a common FCP charging methodology to Ofgem for approval by 1 September 2010 ready for implementation on 1 April 2011.

Governance arrangements

1.8. Following consultation[5], we decided in October 2008 that the governance arrangements applying to the new charging methodologies should among other things allow for modification proposals to be raised by any party materially affected by the methodologies, and allow for parties materially affected to be consulted on any proposed modifications to the methodologies. We considered that this could be achieved in a number of ways, but that it was important to create a legal obligation on the DNOs to deliver on this issue to ensure that the new methodologies remained responsive to changes in the needs of network users. New licence requirements to this effect came into force on 1 July 2009.

1.9. On 15 July 2009 the DNOs formally submitted their governance proposals to us in a paper titled 'Governance and change control arrangements for the DNO distribution charging methodologies'. The DNOs consider that the most appropriate way of providing a governance structure for the HV/LV common methodology and the EHV common methodologies when they come into effect is to formally incorporate the methodologies within the Distribution Charging and Use of System Agreement (DCUSA) such that they become subject to the DCUSA change control procedures. To achieve formal incorporation of the methodologies within the DCUSA the DNOs propose a new standard licence condition 22A as well as a number of consequential DCUSA modifications.

1.10. We have reviewed the DNOs' governance proposals and have decided to make provision to allow for the incorporation of the HV/LV common methodology and the EHV common methodologies within the DCUSA when they come into effect. The full reasons for our decision are set out in Chapter Three of this document. In parallel to the publication of this decision, and as part of the statutory notice of the licence modifications necessary to oblige the DNOs to implement revised EHV charging, we have therefore also published modification proposals containing the licence changes necessary to oblige the DNOs to achieve the formal incorporation of the common HV/LV methodology and the common EHV methodologies within the DCUSA from the time of implementation. We intend to issue a direction concerning the DNOs governance proposals after the complementary DCUSA modifications necessary to complete the incorporation of the methodologies within the DCUSA are submitted to us.

[5] 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.

Structure of this document

1.11. Chapter Two of this document sets out the high level choice of EHV methodologies facing the DNOs in meeting their EHV charging obligations. Chapter Three describes the nature of the DNOs' governance proposals in full, and explains the reasons for our governance decision. Chapter Four sets out the next steps for the project. Appendix One contains a description of the principles and assumptions which should be applied by those DNOs who choose to develop and implement a common LRIC methodology. Appendix Two contains a description of the principles and assumptions which should be applied by those DNOs who choose to develop and implement a common FCP methodology.

1.12. The statutory consultation notice published in parallel to this document contains the new licence conditions necessary to oblige the DNOs to deliver revised EHV charging and governance arrangements. This decision document provides the detail and context behind this parallel statutory consultation on the new licence conditions for EHV charging and common open governance arrangements.

2. Decision on EHV charging

Chapter Summary

This chapter sets out the high level choice of methodologies facing the DNOs in meeting their EHV charging obligations. We also explain our decision on the definition to be applied to the common EHV charging boundary and set out our expectations regarding the development of the common LRIC and common FCP methodologies between now and the submission of the methodologies on or before 1 September 2010.

Choice of common methodologies

Background

2.1. In March we set out our intention to introduce a licence obligation on each DNO to introduce a new charging methodology at the highest voltage ('extra high voltage', EHV) levels for implementation by 1 April 2011. Bearing in mind the different views DNOs hold about the best methodology for EHV charging, we decided that each DNO can choose whether to work with other DNOs on a common methodology using the long run incremental cost (LRIC) method or using a version of the forward cost pricing (FCP) approach.

2.2. To assist progress towards development of the EHV methodologies, we have set out the principles and assumptions to be used for each of these methodologies in appendices to this document.

2.3. The principles and assumptions to be applied in the development of the common LRIC methodology are based on the version of the LRIC methodology implemented by Western Power Distribution (WPD) on 1 April 2007 and were set out in our October decision document last year. The LRIC methodology appendix has now been updated in this document to take account of the splitting of this project between EHV and lower voltage levels since October and to achieve a degree of consistency between the FCP and LRIC appendices to this document.

2.4. The principles and assumptions to be applied to the development of the common FCP methodology are based on a modified version of the FCP model submitted to Ofgem by Scottish Power in May 2008 and on the subsequent amendments to that model jointly submitted to Ofgem by the G3 group on 16 July 2009.

2.5. We have looked at both of these charging methodologies in detail and remain of the view that the LRIC methodology would provide the most cost reflective foundation for the common methodology at EHV level. Although our preference for LRIC over FCP is finely balanced (in that FCP does have benefits over LRIC such as greater stability and predictability of charges), we continue to have concerns about the cost reflectivity of the FCP methodology. Given these concerns, and to ensure customers are adequately protected, as part of the general review of investment in the following price control review (DPCR6) we will scrutinise the investment decisions of those DNOs choosing to implement the common FCP methodology to ensure that it has not led to inefficient capital expenditure as a result of poor cost signalling.

Development of methodologies

EHV CLM proposal

2.6. The CLM proposal published today places an obligation on each DNO to choose and develop a common EHV distribution charging methodology (EDCM) that conforms to the principles and assumptions as set out by the Authority under one of the two descriptions set out in Appendix One and Appendix Two to this document, namely:

- the methodology described as the long run incremental cost methodology; or
- the methodology described as the forward cost pricing methodology.

2.7. This licence approach to referencing the requirements of the methodologies is the equivalent of the approach used for the HV/LV common methodology (CDCM) where the May CLM proposal referenced the requirements as set out in our March decision. The purpose of setting out the principles and assumptions is to provide the DNOs with a description of the essential requirements of the two methodologies in order that they have a clear indication of what is expected of their submission. They are not intended as a complete or inflexible set of instructions as to what the methodologies should look like. We are committed to engaging fully with the DNOs as they develop the EDCM and will respond to requests for clarification on issues which arise in the development process. DNOs will need to jointly ensure that the common methodology they select for charging at the highest voltage levels links effectively with the method for charging at lower voltages.

2.8. We expect DNOs to select the approach they intend to apply and work with other DNOs who have selected the same approach to develop a common version of the methodology. We are content that the process developed by the Energy Network Association's (ENA) Common Methodology Group (CMG), has worked well for the development of the arrangements at lower voltages[6], with the DNOs bringing forward new developments, and in some cases improvements, to the CDCM that we had not originally considered. A similar process is appropriate for the development of the common EHV methodologies in the period following publication of this decision. We expect the DNOs to use the appendices as templates on which to base their approach but we are open to discussion where DNOs believe they have a better or more appropriate approach to propose over areas of detail. Where this is the case we expect DNOs to fully justify the approach taken.

[6] For further detail on this work see the ENA's website at http://2009.energynetworks.org/structure-of-charges/.

2.9. Whilst DNOs will select one of two approaches to apply for EHV-level charging, we expect DNOs to acknowledge where elements beyond the basic cost modelling of the two different EHV charging approaches are the same and to work towards common solutions across all DNOs where appropriate. This will cover areas such as the formulation of final charges as well as interactions with the CDCM and IDNO charging. Further information on these areas is set out in Appendices One and Two to this document.

2.10. The drafting of the EHV CLM proposal replicates the structure of the licence concerning HV/LV charging. Proposed condition 50A sets out the obligation on each DNO to choose, develop and submit one of the two common methodologies with accompanying governance arrangements to the Authority for approval by 1 September 2010, while proposed condition 13B sets out the enduring requirements relating to the EDCM after its implementation and is contained in Appendix 1 of 50A ready for implementation on 1 April 2011. Proposed condition 22A has been developed by the DNOs as a way of fulfilling the governance obligations set out in condition 50 for the CDCM and replicated in proposed condition 50A for the EDCM and proposes the incorporation of distribution charging methodologies within the DCUSA. A full explanation of our decision on the governance of the common methodologies is set out in Chapter Three.

Charging to Independent Networks

2.11. As part of the approach to the CDCM we required the DNOs to develop a common approach to charging for Independent Distribution Network Operators (IDNOs) who connect to and use their networks. The decision did not specify what approach should be taken in this area and only required that the DNOs work with IDNOs to develop the arrangements. This work is near conclusion and we expect to receive from the DNOs a common approach to IDNO charging for HV/LV by 1 September.

2.12. IDNOs predominantly connect to the DNOs' network at HV and LV however there are a number of EHV-connected IDNOs. We therefore propose to adopt a similar approach to IDNO charging for the EDCM whereby the DNOs work together to develop common arrangements. Our decision document does not specify the underlying principles and assumptions for IDNO charging at EHV.

2.13. This is a backstop position and we consider that the DNOs should be developing revised charging arrangements for EHV IDNO connections as a matter of urgency.

Future charging developments

2.14. We expect DNOs to continue to address the areas for future development set out in our October decision document. The main elements that DNOs are expected to further develop concern:

- tariff structures,
- information to help users predict their charges,
- proposals addressing stability, transparency and predictability of charges.

Scrutiny of EHV investment decisions

2.15. Consistent with our March decision, we continue to consider that it would be appropriate to review the investment decisions of those DNOs implementing the common FCP methodology to ensure that it has not led to inefficient capital expenditure as a result of poor cost signalling. It is our intention that the findings of the review will be consulted on as part of the process of reviewing the revenues the DNOs' require for the following regulatory period. Where we find evidence of inefficient capital expenditure resulting from poor cost signalling we will use this analysis to inform revenue allowances for final proposals for DPCR6 and reserve the right not to allow all such investment to be funded through the price control.

2.16. It has been suggested by some DNOs[7] that it may be appropriate for us to subject the performance of the LRIC methodology to the same review as that proposed for the FCP methodology. Given that our concerns over cost reflectivity relate primarily to the FCP methodology we do not consider that this would be appropriate, but we do note that under condition 13 of the distribution licence licensees have an obligation to keep their charging methodologies under review on an annual basis, and so we would expect DNOs to take steps to progress modifications and to address any unintended consequences of either the common FCP or the common LRIC methodology in a timely manner.

EHV boundary

2.17. An issue that has been raised in the course of this project is to consider where the methodology for the highest voltage levels should end and where the more average model used for charging customers at lower voltage levels should apply. In the course of this debate it has become clear that currently not all DNOs apply exactly the same dividing line to determine whether customers are charged on an average or a more specific basis. The majority of DNOs currently treat a small number of their customers as if they are connected at the highest voltage levels where they are actually connected and / or metered further down the distribution network due to the specific nature of these large connections. For example, some DNOs currently apply their EHV methodology in calculating charges for customers metered on the 11kV busbar of a primary substation with a primary voltage of 33kV or higher, while others do not.

[7] This view was expressed in the meeting of the DCMF on 3 April 2009 and was represented in two of the responses to the statutory consultation on our May CLM. Responses to this consultation are available to view on Ofgem's website at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=125&refer=Licensing/Work/Notices/ModNotice.

2.18. We have defined the HV/LV common methodology (CDCM) as applying to 'premises or Distribution Systems connected to assets on the licensees Distribution System at a voltage level of less than 22 kilovolts, but excluding any such premises or Distribution Systems in respect of which the Use of System Charges levied by the licensee are calculated on the same basis as those levied in respect of premises or Distribution Systems connected to assets on the licensee's Distribution System at a voltage level of 22 kilovolts or more'[8]. This drafting specifically recognises that DNOs do not apply a common boundary between HV/LV and EHV charging as at the time of drafting the licence condition, it was unclear how many customers were affected and what the impact would be on those parties of delineating a common boundary. The licence requirement therefore maintained the status quo.

2.19. In our view achieving consistency in the application of the EHV boundary across all DNOs is an important component of delivering a common approach. Not least for suppliers who, when entering into contracts with customers, will need to know the basis of distribution charging. Legacy arrangements will significantly reduce transparency in this area – it will also cause confusion to customers who operate across a number of distribution services areas. With this in mind we asked DNOs in May to provide full information on the impact of implementing a common EHV charging boundary along with their views on a solution.

2.20. On average DNOs noted a handful of customers would be affected if the charging boundary were to be set as connections metered at 22kV and above (around 40 connections across all DNOs). However, a number of DNOs noted that this would include some very significant demand connections, for instance large industrial customers who are connected through sole use 132/11kV substations. Often these arrangements have been developed due to the industrial nature of the processes undertaken and the disturbance they can cause to power supply quality if connected at lower voltages. DNOs noted that extending the charging boundary below this on a consistent basis would involve a lot more connections, though DNOs' estimates of the numbers affected ranged from very few to several hundred.

2.21. The impact on customer charges should they switch between charging methods could be substantial. Estimates from DNOs note that moving a customer from a site specific charge based on an EHV charging methodology to a charge based on an HV/LV charging methodology would increase charges on average by anything from thirty per cent to well over one hundred per cent. Moving a customer in the opposite direction would have the opposite effect, although this would not be the case in every instance.

2.22. Although the number of customers affected is relatively small, because the potential impact on individual customers' charges is material we consider that this matter warrants consultation prior to deciding whether an enduring common boundary is appropriate and the level at which the boundary is set. In our proposed EHV CLM published today we have defined the EHV common methodology (EDCM) as applying in a manner consistent with the status quo pending the outcome of further consultation on this issue.

[8] Electricity Distribution Licence, Condition 50.10.

2.23. Given the delay before the revised EHV charging arrangements take effect we intend that this matter is fully considered ahead of 1 September 2010. At this time we are minded to determine a common boundary among all DNOs for the reasons set out above and to fully define the common EHV boundary within the distribution licence once this consultation process has been concluded.

3. Decision on governance arrangements

Chapter Summary

This chapter describes the nature of the DNOs' governance proposals and explains the reasons for our governance decision. We also provide a summary of the consultations carried out in respect of governance proposals and comment on the interaction between the Structure of Charges Project and the wider Codes Governance Review of charging methodologies being undertaken by Ofgem's Industry Codes and Licensing team.

Principles for revised governance arrangements

3.1. We have been concerned about the effectiveness of governance arrangements for network charging methodologies for a number of years. In late 2007 we announced the start of a comprehensive review of industry code governance[9] and in a decision document in June 2008[10] confirmed that the question of whether charging methodology governance arrangements were fit for purpose would be a key part of the review.

3.2. As part of the Code Governance Review, in September last year Ofgem published a consultation on charging methodology governance options[11]. In the context of Ofgem's commitment to the principles of better regulation and to improving the accessibility, transparency and accountability of regulation the consultation sought views on the principle of whether charging methodologies should be open to change by network users and customers. The consultation also set out a number of high level governance options which would, to varying degrees, reform the governance arrangements applying to charging methodologies. The options were as follows:

- Option One – Maintain status quo
- Option Two – Modify the current licence regime
- Option Three – Industry code governance
- Option Four – New charging methodology change management code.

[9] 'Review of industry code governance', Ofgem, 28 November 2007.
[10] 'Review of industry code governance – Scope of the review', Ofgem, 30 June 2008.
[11] 'Code governance review: Charging methodology governance options', Ofgem, 17 September 2008.

Structure of charges consultation on governance of common distribution charging methodology

3.3. Current arrangements for handling modification proposals to distribution use of system charging methodologies are set out in standard condition 13 of the distribution licence. Under the condition licensees are required to review their methodologies at least once per year and to make such modifications of the methodology as are necessary for the purpose of better achieving the relevant charging methodology objectives set out within the condition. Licensees have no formal obligation to consult with industry parties or other DNOs prior to submitting modification proposals, and the development of modification proposals is something over which other industry parties, including those materially affected by charging methodologies, have no control. As such charging methodologies are the sole responsibility and preserve of individual distribution licensees.

3.4. In July last year as part of our decision to require DNOs to implement a common distribution charging methodology, we consulted for the first time on the appropriate form of governance which should apply to the common distribution charging methodology. We liaised with the Industry Codes and Licensing team on the governance options presented. The key issues of accessibility, transparency and accountability identified by the Code Governance Review have been central to the development of our thinking on governance arrangements within the Structure of Charges project. However a number of the key characteristics of the distribution Structure of Charges project - namely that we consider it necessary to implement a common methodology to the largest extent possible, and that implementation of the common methodology at the lower voltage levels should be achieved by 1 April 2010 - have meant that we have been prepared to reach a decision on the governance applying to the common methodology on a different timescale and to a potentially different specification from the Code Governance Review.

3.5. We consider that the preservation of a common methodology necessitates the provision of a common governance structure from the date it comes into effect. As we also consider it imperative that the common methodology is capable of industry led modification, maintaining the status quo arrangements was not an option for the structure of charges project.

3.6. The three options we therefore consulted on were as follows:

Option 1 - Industry code governance

3.7. In this option, we outlined that the common methodology would be subject to the DCUSA governance arrangements. This would mean that suppliers and some generators as well as network operators would be able to raise modification proposals to the methodology. We considered that the benefits of this approach would be that it would provide users with greater ability to contribute to the development of the methodology by way of a formal modification mechanism, and that it would take account of an existing industry framework with an already established appeals mechanism.

Option 2 - Modify the current DNO licence

3.8. Under this option we set out that we would seek to modify SLC13 to include within the condition that any modification proposal should apply to the common charging methodology, unless otherwise directed by the Authority. To ensure greater industry access to the charging methodology, under this option we set out that we would also propose that the modified condition would set out formal obligations on licensees to consider and formally respond to change proposals submitted by non-DNO industry parties, including holding industry forums, carrying out Impact Assessments and bringing forward charging methodology modification proposals where appropriate.

Option 3 - New Charging Methodology Code

3.9. We set out that the governance arrangements envisaged under this option would be delivered via a standard set of modification rules. We considered a potential benefit of this option would be that in developing a new code, the governance arrangements could be tailored to precisely meet the requirements of a common charging methodology. Conversely, we acknowledged that the potential downside of this option could be that development and introduction of a new code could have significant cost implications for industry parties and could therefore be viewed as economically inefficient relative to the number of modifications which could reasonably be expected to be proposed.

Responses

3.10. Respondents to the July consultation on governance agreed that it was essential that governance arrangements be developed and implemented in parallel with the development on the CDCM, for implementation by April 2010. There was no clear consensus as to whether the governance arrangements would be best set out in code, or via a licence condition, but there was majority support for our view that, regardless of which option was selected, it was important that the modification procedure of the common methodology allowed for non-DNOs to have modification proposals considered and consulted on. A majority of respondents considered that creating a new industry code to handle modification proposals would be a disproportionate and unnecessarily costly option.

October decision and May CLM proposal

3.11. Following the July consultation, in October we decided that it would be appropriate to place a licence obligation on DNOs which required them to develop a set of governance arrangements for implementation on 1 April 2010 which satisfied the following requirements:

- arrangements must provide for DNOs to organise regular meetings with other Authorised Electricity Operators, and any other interested electricity users, for the purpose of discussing the further development of the methodology;

- arrangements must provide for a process by which DNOs can formally receive modification proposals from other Authorised Electricity Operators, or any other persons whose interests are materially affected, and consult with industry on the merits of those proposals;
- arrangements must provide for DNOs to have a report prepared for submission to the Authority which sets out the conclusions reached about the modification proposal in question, evaluates the proposal against the relevant charging methodology licence objectives, and makes a recommendation to the Authority concerning the implementation of that proposal; and
- arrangements must provide for a process by which the modification arrangements themselves can be modified and must provide for the appropriate publication of an up to date copy of the charging methodology.

3.12. Importantly we did not consider that it was necessary for the licence to specify the form that the governance arrangements should take. Our priority was to put in place a set of governance obligations which satisfied the wider aspirations of the Code Governance Review, but which, with the exception of maintaining the status quo, were flexible enough to be viewed as broadly compatible with any of the main governance options consulted on in the Code Governance Review September consultation.

3.13. The decisions taken in October concerning the charging methodology and governance arrangements at the lower voltage levels of the distribution networks took effect in the distribution licence on 1 July 2009 via the May CLM proposal.

CMG governance proposals

3.14. New condition 50.23 of the distribution licence requires that 'the licensee, in conjunction with all other Distribution Services Providers, and in consultation with other Authorised Electricity Operators, must develop arrangements for handling modification proposals to the CDCM (HV/LV common distribution charging methodology) and submit them for approval to the Authority by not later than 1 September 2009'. Having pursued work on the governance arrangements through the Common Methodology Group (CMG), and having consulted members of the Distribution Charging Methodology Forum in April[12], on 15 July 2009 the DNOs formally submitted their governance proposals to us in a paper titled 'Governance and change control arrangements for the DNO distribution charging methodologies'.

3.15. The key recommendation of the CMG's paper is that the common charging methodologies (both the HV/LV common methodology and the common EHV methodologies) should be incorporated into the DCUSA and therefore be subjected to

[12] For further detail on the DCMF see the ENA's website at http://2009.energynetworks.org/distribution-charging-methodol/.

the governance and change control mechanisms of the DCUSA code[13]. The CMG considers that incorporation within the DCUSA would provide the most appropriate governance arrangement for the common HV/LV methodology for the following reasons:

- The DCUSA provides existing change control and governance arrangements that almost entirely meet the core requirements for the arrangements set out in proposed condition 50 (of the October proposal).

- The proposed timetable for the implementation of the CDCM (1 April 2010) would make delivery of an entirely new suite of governance and change control arrangements difficult.

- In the CMG's view the resource and expense of creating a new suite of governance and change control arrangements would be difficult to justify.

- The CMG also considered that as the DCUSA has been designated by government for the purposes of the Energy Act 2004 appeals regime, an additional benefit would be that Ofgem's decisions concerning future modifications of the CDCM would automatically be subject to a merits-based appeals mechanism.

3.16. To allow for the formal incorporation of the common distribution charging methodologies within the DCUSA the DNOs consider it is necessary to create a new standard condition 22A to ensure that the methodologies are brought properly within the scope of the matters for which the DCUSA can make provision. Proposed condition 22A would also have the effect of specifying that the relevant objectives against which common methodology modification proposals are to be assessed would be those specified in Part B of the condition (these are consistent with the relevant charging methodology objectives of existing condition 13A) and not the relevant DCUSA objectives. The effect of the incorporation of the common charging methodologies within the code as proposed in condition 22A would also be to relocate the Authority's powers to veto or non-veto use of system charging modification proposals from the distribution licence to the DCUSA.

Ofgem's decision

3.17. We have reviewed the DNOs' governance proposals and it is our view that the DNOs' proposal of formally incorporating the common HV/LV methodology within the DCUSA would be compatible with meeting the governance obligations specified in

[13] The DNOs' proposal to incorporate the common HV/LV charging methodology within the DCUSA was originally proposed by the DNOs as part of their April governance consultation and it was their intention at that stage to include SLC22A within the May CLM. We excluded SLC22A from the May CLM because the DNOs consultation on their governance proposals had not concluded at that time, and because we had not yet had time to review the DNOs proposals in full.

Condition 50. In parallel to the publication of this decision, and as part of the statutory notice of the licence modifications necessary to oblige the DNOs to implement revised EHV charging, we have therefore published modification proposals containing the licence changes necessary to provide for the formal incorporation of the HV/LV common methodology within the DCUSA from April 2010.

3.18. The DNOs have also proposed that the licence condition necessary to achieve the incorporation of the HV/LV methodology within the DCUSA should also provide for incorporation of the common EHV methodologies within the DCUSA from the time of their implementation in April 2011. We consider that the governance obligations and modification arrangements applying to the common EHV methodologies should be the equivalent of the arrangements applying to common HV/LV methodology and we have therefore provided for this within proposed condition 22A of the CLM proposal.

3.19. As part of their governance proposals the DNOs also included detail of the DCUSA modifications they consider will be required to complete the incorporation of the charging methodologies within the code. We are not commenting on this detail and are therefore not making a formal direction on the arrangements for handling modifications in this decision document. We intend to engage with the DNOs with regard to the drafting of the proposed DCUSA modifications following publication of this decision, but we are required to evaluate any DCUSA modifications proposals against the relevant objectives of the DCUSA and we do not intend to publish a formal decision on these proposals until they are submitted to us under the DCUSA procedures. We are not at this time aware of any reason why the DCUSA should not be capable of modification in the manner necessary to complete the incorporation of the common charging methodologies within it, but we consider that it would be appropriate to defer publication of a formal direction on the DNOs governance proposals until publication of our decision on the DCUSA modifications submitted to us.

3.20. We have reached our decision on governance for the following reasons:

- Distribution charging methodologies impact on a wide range of electricity users. In our view it is appropriate that all parties materially affected by the methodologies have the ability to contribute to their future development. We consulted on the principle of widening access to distribution methodologies in July last year and received widespread support from a majority of DNO and non-DNO parties for doing so;

- The DNOs consulted on their proposal to incorporate the HV/LV methodology within the DCUSA in a paper distributed among Distribution Charging Methodology Forum (DCMF) members in April this year. The paper set out that the DNOs proposed to subject the HV/LV methodology to the governance structures of the established distribution code, explained what this entailed, and explained that they did not consider that the alternatives, modification of the current licence regime or the creation of a new charging methodology code, would be appropriate in the context of the structure of charges project. The DNOs did not receive any formal representations to the paper, but the paper received majority support among industry parties present at the DCMF meeting of 3 April 2009;

- We consider that the DNOs' proposals represent a time and resource efficient way of delivering governance arrangements for the common methodologies. Utilising the existing governance structures of the DCUSA means that arrangements for handling modification proposals do not have to be designed from scratch. Further, the importance of the DNOs submitting the HV/LV methodology for implementation by 1 April 2010, means that the time available for developing completely new modification arrangements is relatively constrained; and

- Given the short timescale for developing the new methodologies, and the continuing changes to network use, we place a high priority on arrangements that allow for incremental improvements to be proposed to the common methodologies from their implementation.

3.21. In reaching our decision, we note that a change proposal to the DCUSA may be made by any DCUSA party, the National Consumer Council, the National Electricity Operator or by any person or body that may from time to time be designated in writing by the Authority[14]. DCUSA parties include distribution network operators, independent distribution network operators (IDNOs), suppliers and a number of distributed generators, but do not include electricity customers. Because of our power to designate the ability to raise change proposals to other parties we are not overly concerned that parties who want to raise modifications will be excluded. Nevertheless the DNOs may want to consider whether the DCUSA should be modified such that all parties materially affected by distribution charging methodologies have the ability to raise modification proposals by right rather than by exception.

3.22. Subjecting the common charging methodologies to the governance and change control mechanisms of the DCUSA will ensure that the methodologies are responsive to the needs of network users and we consider that it is appropriate that the new methodologies, particularly at EHV level, should be capable of modification if appropriate from the outset. However, having reached the decision in March that it would be appropriate to allow the DNOs to choose between implementation of a common LRIC and a common FCP approach for EHV charging, in the interests of a degree of charging stability, we do not consider that it would be appropriate for modification proposals to be developed with the intention, explicit or otherwise, of substituting one methodology for the other within the next price control period. For this reason we have taken steps in proposed condition 22A.14(b) to provide the Authority with the power to veto any modification proposals we consider to have as their purpose the full or substantial substitution of one methodology for another prior to 1 April 2015.

[14] As set out in clause 10.2 to the Distribution Connection and Use of System Agreement.

4. Next steps

4.1. Table 1 below highlights a number of the key milestones in the development of the structure of charges project to date, and sets out the timeline for delivery and implementation of the common HV/LV and EHV charging methodologies and common governance arrangements in the period up to 1 April 2011.

Table 1

Structure of charges project developments	Date
Consultation on EHV charging, governance and decision to implement commonality	Jul-08
Decision on EHV charging/CLM proposal to deliver common methodology and governance	Oct-08
October CLM proposal blocked	Nov-08
Consultation on next steps for Structure of charges project	Dec-08
Decision to split the project between delivery at lower and extra high voltages	Mar-09
CLM proposal concerning HV/LV charging and governance	May-09
CLM concerning HV/LV charging and governance takes effect	01-Jul-09
CLM proposal concerning EHV charging and governance	31-Jul-09
DNOs to submit common methodology for HV/LV charging	01-Sep-09
Statutory consultation on CLM proposal for EHV charging closes	04-Sep-09
CLM concerning EHV charging and governance takes effect	01-Oct-09
DCUSA modification proposals concerning incorporation of charging methodologies to be submitted to Ofgem	Autumn 09
Ofgem to publish direction on DNOs' governance proposals	Autumn 09
Implementation of common methodology for HV/LV charging	01-Apr-10
DNOs to submit common methodologies for EHV charging	01-Sep-10
Implementation of common methodologies for EHV charging	01-Apr-11

Appendices

Index

Appendix 1 – Common long run incremental cost methodology: principles and assumptions

Introduction

1.1. This appendix sets out the principles and high-level detail that should be adopted as the common approach to EHV use of system charging that is based on the LRIC model. Areas requiring further development by those DNOs adopting the LRIC approach are set out below in italics.

1.2. The LRIC model calculates nodal incremental costs. These costs represent the brought forward (or deferred) reinforcement costs caused by the addition of an increment of demand or generation at each network node. The method models the impact changes in users' behaviour have on network costs.

1.3. In particular, the LRIC model takes account of the effects a change in user behaviour has on the network by using AC power flow analysis, which enables the calculation of the time needed before elements of the network require reinforcement and subsequently the net present value (NPV) of the future costs of reinforcement. The incremental cost is equal to the difference in the NPV of reinforcing under existing conditions and when an increment of new demand or generation is added.

1.4. To calculate charges for EHV demand and generation customers, a common LRIC method should consist of the following stages:

- LRIC model
    - AC power flow analysis
    - Calculation of incremental costs including the consideration of peak and off-peak demand conditions
- Scaling to recover allowed revenue
- Derive final EHV charges.

1.5. We also note the interaction with the common distribution charging methodology (the CDCM) at lower voltages and arrangements for developing charges for independent distribution network operators (IDNOs).

LRIC model

Power Flow Analysis

1.6. Power flow analysis calculates the effects of adding an increment of demand or generation to the distributor's network. In particular, it calculates the power flows passing over the various assets of the distributor's network under base and incremental conditions using peak (typically during the winter period) and off-peak (typically during the summer period) demand data.

1.7. The power flow analysis should calculate the following nodal based values:

- Base power flows using peak and off-peak demand data, and
- Incremental power flows using peak and off-peak demand data.

1.8. The EHV connections on a distributor's network include single customers connected to the system using assets that have been sized to their connection requirements. Costs for these assets should be excluded from the calculation of incremental costs if they have already been paid as part of a connection charge. Replacement and operation and maintenance costs for these assets should also be excluded from the calculation of incremental costs, but may be incorporated into a customer's final charge ('sole use asset charges').

1.9. Power flow analysis uses a number of processes and assumptions as follows:

- A representation of the entire EHV network captured using appropriate power flow modelling software. The modelled network should be based on the network expected to exist and be in operation in the first regulatory year that charges are being calculated for, based on the distributor's long term development statement.
- Nodal demand and generation data should be used, which is based on actual metered network usage data that is recovered from the distributor's Supervisory Control and Data Acquisition (SCADA) (or equivalent) system. In particular:
    - o Demand data - For the peak demands, the model uses demands consistent with those used to assess reinforcement. This includes diversity to allow a complete EHV system model to be run. Off-peak demands are taken as being a percentage of peak demands. This percentage is derived for each grid supply point (GSP) and applied to the demands supplied by that GSP.
    - o Generation data – for the peak period generation is zero unless it is deemed to contribute to network security in accordance with Engineering Recommendation P2/6[1]. The generation export used for the off-peak

[1] Engineering Recommendation P2/6 is intended as a guide to system planning and is published by the Energy Networks Association (http://2009.energynetworks.org). It takes into account the results of extensive reliability studies using fault statistics and risk analysis and the relationship of these to the costs of system reinforcements, including the effects on losses.

period is the maximum agreed export capacity. These are broadly similar to the assumptions that are used by distributors when investment planning.
  - Distributors should cleanse demand and generation data so that it is representative of typical network usage. That is, anomalous power flows, which represent, for example, demand levels at a time when the network is experiencing an outage, should be removed from the data set and the effects of load management schemes should be taken account of.
- AC nodal power flows are modelled. Power flows should be calculated for peak and off-peak base conditions ($BasePowerFlow(MVA)$) and for peak and off-peak conditions plus an increment of demand or generation ($IncPowerFlow(MVA)$).
- Increment
  - A ±0.1MW increment should be used in relation to calculating the active demand and generation elements of the incremental power flows, assuming that the power factor for demand is 0.95 and unity for generation.
- Growth Rate
  - A single underlying network growth rate is used to assess the timing of future reinforcement for demand and generation charges. It represents the long run growth of all distributors' networks and is set to 1% growth per annum.
  - To facilitate predictability and stability, the growth rate is used throughout the model and as with all assumptions, distributors should keep this growth rate under review. As a minimum, the rate should be reviewed and reset when distributors' price controls are reviewed every five years.
- A pair of Security Factors should be determined for each asset using a full N-1 contingency analysis assuming peak and off-peak demand conditions. These factors are used to determine the usable capacity of network assets during peak and off-peak conditions. They are recalculated each time the network is changed or new load estimates used.
  - Power flows under N-1 contingency conditions are used to calculate Security Factors.

Calculation of incremental costs

1.10. The incremental cost of reinforcing a node is the difference in the NPV of reinforcing it under base conditions and with an increment of demand or generation added.

1.11. The nodal incremental cost is therefore calculated using the following formulae:

$$IncrementalCostAtNode = \sum_{i=1}^{B} \Delta Ci$$

Where ΔCi is the change in reinforcement costs of the asset in branch i when an increment of demand or generation is added to the node. B is the number of branches connected to the node.

$$\Delta Ci = [NetPresentValue(inc) - NetPresentValue(base)] \times AnnuityRate$$

$$NetPresentValue(inc) = \frac{CostOfReinforcementSolution}{[1 + DiscountRate]^{YearsToReinforcement(inc)}}$$

$$NetPresentValue(base) = \frac{CostOfReinforcementSolution}{[1 + DiscountRate]^{YearsToReinforcement(base)}}$$

$$AnnuityRate = \frac{DiscountRate}{1 - \left[\frac{1}{[1 + DiscountRate]^{AnnuityPeriod}}\right]}$$

$CostOfReinforcementSolution$ is the modern equivalent asset value (MEAV) of reinforcing the particular asset, bearing in mind the requirements of similar historic projects[2]. This cost is the same under both base and incremental conditions.

$DiscountRate$ is equal to the (pre-tax) cost of capital set by Ofgem as part of distributors' current price control.

$AnnuityPeriod$ is the period over which costs are annuitised. This period is set to 40 years and represents the typical life of an asset.

1.12. Power flows and asset capacities calculated by the power flow analysis under base and incremental conditions are fed into the following formulae to calculate the time to reinforcement for each asset under base and incremental conditions.

$$YearsToReinforcement(base) = \frac{\log AssetCapacity - \log BasePowerFlow(MVA)}{\log[1 + GrowthRate]}$$

$$YearsToReinforcement(inc) = \frac{\log AssetCapacity - \log IncPowerFlow(MVA)}{\log[1 + GrowthRate]}$$

1.13. A pair of incremental costs is calculated for each asset using peak and off-peak demand power flows (a peak incremental cost and an off-peak incremental cost).

Consideration of peak and off-peak demand conditions

1.14. Once incremental costs are calculated for each branch using peak and off-peak demand data, those costs that relate directly to each customer's use of the network and that drive the need to reinforce the network are summed together.

1.15. In particular, for site-specific EHV demand customers, their incremental charge is calculated taking account of peak and off-peak network conditions as follows:

[2] Distributors should use the specifications and costs of similar, past reinforcement projects as a means for determining the requirements and costs of a particular future reinforcement project.

- Determine whether reinforcement is driven by peak or off-peak network demand conditions for each branch used by the demand customer. The period that is deemed to drive reinforcement is the period with the highest positive associated incremental cost signal.
- Where peak conditions drive reinforcement, the branch charge is the peak incremental cost for the particular asset being considered multiplied by the 'peak charging demand'[3].
- Where off-peak conditions drive reinforcement, the branch charge is the negative of the off-peak incremental cost for the particular asset being considered multiplied by the 'off-peak charging demand'.
- The customer's incremental charge is the sum of all branch charges[4] which are used by the customer (relevant branches).

1.16. For site-specific EHV generation customers, their incremental charge is calculated as follows:

- Determine whether reinforcement is driven by peak or off-peak network demand conditions for each branch used by the generation customer. The period that is deemed to drive reinforcement is the period with the highest positive associated incremental cost signal.
- Where off-peak conditions drive reinforcement, the branch charge is the peak incremental cost multiplied by the agreed export capacity.
- Where peak conditions drive reinforcement, the branch charge is the negative of the peak incremental cost multiplied by the level of demand expected to contribute to network security as set out in engineering recommendation P2/6.
- The customer's incremental charge is the sum of all branch charges[5] which are used by the customer (relevant branches).

1.17. For individual EHV-connected customers, the peak demand used for charging purposes ('peak charging demand') should be based on an average of the customer's demands that coincide with GSP peak demand during the months that surround the GSP peak demand. The off-peak demand used for charging purposes ('off-peak charging demand') for individual EHV customers is an average of the customer's lowest level of demand that coincides with the lowest GSP demand recorded during the months that surround the lowest GSP demand. Where a customer's connection is new or significant changes have been made to the agreed capacity a best estimate will be used for the 'peak charging demand' and 'off-peak charging demand' taking into account the typical ratio of agreed supply capacities to charging demands for existing customers.

1.18. When calculating the peak and off-peak charging demands, distributors should use the most recent, available and complete set of demand data.

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[3] Peak and off-peak charging demands are described in more detail in paragraph 1.17.
[4] Only assets that experience a change of greater than 1kVA in the power that flows across them are used in the calculation of branch charges.
[5] Only assets that experience a change of greater than 1kVA in the power that flow across them are used in the calculation of branch charges.

1.19. The demand used for charging purposes for connections to other licensed distributors needs further consideration by distributors as part of their development work for IDNO charging.

Scaling

Summary

1.20. In accordance with their price controls, licensed distributors are allowed to recover revenue that covers their capital and operational expenditure requirements.

1.21. Given forecast network usage, the incremental charge will recover a proportion of a distributor's allowed revenue. This amount may be over or under the overall allowed revenue.

1.22. Consequently, revenue scaling is used to regulate the incremental charges so that they recover revenue that is equal to the distributor's allowed revenue.

Fixed adder approach

1.23. In relation to EHV charges, a fixed adder revenue scaler should be used to ensure that EHV charges do not significantly over or under recover revenue. The adder will be in £/kVA.

1.24. To calculate the size of the EHV demand fixed adder in relation to demand allowed revenue, the following steps are followed:

- Total demand allowed revenue is split between the EHV network and lower voltage networks using MEAVs. This gives an EHV-related allowed revenue and a lower voltages (HV/LV) allowed revenue.
- Asset quantities used for this evaluation should be consistent with those contained in distributors' Regulatory Reporting Tables together with MEAVs used for long term investment planning.
- Based on the charges calculated in accordance with paragraphs 1.15 to 1.18, forecast revenue from EHV site specific customers is calculated.
- The revenue forecast is subtracted from the EHV allowed revenue, which leaves an amount of revenue yet to be recovered.
- The unrecovered revenue is divided by the forecast winter demand (kVA) to give a unit rate fixed adder (£/kVA), which is incorporated into customers' final tariffs.

1.25. *The approach to generator scaling is to be considered further by those DNOs selecting the LRIC approach.*

Derivation of final charges

1.26. Final site-specific demand charges consist of:

- The customer's incremental charges,
- A fixed adder,
- Sole use asset charges, and
- The allocation of network rates and transmission exit charges.

1.27. Site specific generator charges consist of:

- The customer's incremental charges,
- A fixed adder,
- Sole use asset charges, and
- The allocation of network rates, and where appropriate transmission exit charges.

1.28. The detail around the calculation of sole use asset charges should be further clarified by those DNOs selecting the LRIC approach.

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

Interaction with the CDCM

1.30. LRIC methodology applies at EHV and the CDCM at lower voltages (HV/LV). There is a relationship between these two methodologies as HV/LV customers place demands on the EHV network. The final EHV charges described above will recover a proportion of total EHV-related revenue. The remainder is passed down into the CDCM.

1.31. This remainder is allocated to HV and LV customers in accordance with the CDCM covering charges to customers at these lower voltages.

1.32. *The detail of this interaction is to be worked on by the DNOs.*

Charges to IDNOs

1.33. *Independent distribution network operator (IDNO) charging arrangements are to be developed by DNOs working with IDNOs.*

Appendix 2 – Common forward cost pricing methodology: principles and assumptions

Introduction

1.1. This appendix sets out the principles and high-level detail that should be adopted as the common approach to extra high voltage (EHV) use of system (UoS) charging that is based on a Forward Cost Pricing (FCP) model. Areas requiring further development by those DNOs adopting the FCP approach are set out below in italics.

1.2. The purpose of the FCP model is to calculate annual charges that recover the expected costs of reinforcing parts of a DNO's EHV network before the reinforcement is necessary. Charges calculated by the FCP model each year provide cost signals that are relative to available capacity in a network group, the cost of reinforcing the network group and the expected time before reinforcement would be necessary.

1.3. To calculate charges for EHV customers, a common FCP method should consist of the following stages:

- FCP Model
    - Identify Network Groups
    - Perform contingency analysis
    - Forecast reinforcement costs
    - Derive FCP charges (£/kVA/annum) – demand and generation
    - Derive generation benefits
- Scale to allowed revenue
- Derive final EHV charges

1.4. We also note the interaction with the common distribution charging methodology at lower voltages (the CDCM) and arrangements for developing charges for independent distribution network operators (IDNOs).

FCP Model

1.5. The FCP model determines annual demand and generation £/kVA costs. The steps for calculating charges are set out below.

Demand costs

1.6. *Identify network groups* – the EHV network is split into Network Groups. A Network Group is a contained portion of the DNO's total network that is not electrically connected to another part of the network at the same voltage level under normal operating conditions.

1.7. A Network Group is part of the distribution network, which is normally supplied by a Grid Supply Point (GSP) or Bulk Supply Point (BSP). In situations where GSPs or BSPs are operated in parallel, these are considered as a single Network Group. In Scotland there is a single layer of Network Groups from GSP to 33/11kV substation. In England and Wales, two layers of Network Groups are considered (GSP to BSP and BSP to primary substation – e.g. 33/11kV substation).

1.8. *Perform contingency analysis* – contingency analysis is performed on a forward looking model of the DNO's network in order to identify all likely reinforcement projects within 10 years in order to comply with network security requirements (i.e. those set out in Engineering Recommendation P2/6). This is achieved by performing n-1 and, where required, n-2 AC power flow analysis over the planned model of the DNO's network[1] for each year within a 10 year horizon. The analysis only considers thermal ratings, not, inter alia, fault levels.

1.9. Load flows used in the analysis are based on network demand data from the DNO's Long Term Development Statement (LTDS). The LTDS contains the DNO's forecast for substation load demands for the next 5 years. The ten year forecast uses the 5 years of LTDS data and extrapolates forward for the remaining 5 year period

1.10. The method for extrapolating demand data will need to be developed in more detail by those DNOs that adopt the common FCP approach.

1.11. Following the analysis of the first year, load flows used in each subsequent year are incremented according to forecast network group growth.

1.12. Reinforcement projects identified within the 10 year horizon are used for determining FCP charges.

1.13. *Forecast reinforcement costs* – the method assumes that any reinforcement is undertaken in a standardised way with standardised costs. Typically, it is assumed that the reinforcement of a network component doubles the capacity of that network component.

[1] The planned network is the network expected to exist and be in operation in the first regulatory year that charges are calculated for.

1.14. In practice, when determining the extent and likely cost of a reinforcement project, the DNO should use the same design data that they use to prepare connections offers.

1.15. Where more than one reinforcement is expected in a network group within the 10 year horizon, the total charge rate is the sum of the charge rates for each reinforcement in the network group.

1.16. *Derive £/kVA/annum charges* – the following charging function is used to derive the pre-scaling annual network group FCP charges (£/kVA):

$$FCP_{demand} = i(A / C).(D / C)^{2i / g-1} / (1 - \exp(-2iT))$$

i = the discount rate, which is assumed to be the pre-tax cost of capital set by Ofgem as part of the price control
A = the total cost (£) of each expected network group reinforcement over the 10 year period
C = demand (kVA) of the network group at which each reinforcement would be required
D = initial demand (kVA) in network group
g = demand growth rate given by Ln*(C/D)/y* where *y* is the number of years into the future (up to ten years ahead) when reinforcement is required
T = the 10 years over which the cost is recovered.

1.17. Demand customers in a lower voltage network group pay the charge rate for any higher voltage network group from which they derive their supply.

Generation costs

1.18. The methodology for calculating EHV generation costs each year is similar to that used to derive charges for EHV demand: first, reinforcement costs expected within the next 10 years are forecast, using the same network groups as used for EHV demand; then these costs are spread across total expected EHV generation over the 10-year period to arrive at a set of £/kVA/annum charges.

1.19. Forecast reinforcement costs for EHV generation are calculated by assuming that a “test-size” generator is installed at each network group to estimate reinforcement costs, which are then scaled down by an assumed probability of such a “test-size” generator actually connecting.

1.20. *Test-size generator analysis* - The first step towards estimation of reinforcement costs triggered by generation over the next 10 years is based on the information provided by the hypothetical installation of a test-size generator at each network group. The test-size generator for each voltage level is determined as the 85th percentile of existing generator sizes at that level. The test-size generator is assumed to be installed at the principal substation of each Network Group. The resulting network power flow analysis determines whether or not the test size generator would trigger reinforcement and what these reinforcement costs would be. The analysis considers thermal ratings only, not, inter alia, fault levels.

1.21. *Forecast reinforcement costs* - Once the reinforcement costs associated with the test-size generator have been estimated, they are scaled down by the probability of such generation actually connecting within the next 10 years in order to measure the expected cost of reinforcement for each Network Group. The method for calculating these probabilities is derived by the following steps:

- Total new generation for the 10-year period is forecast by multiplying existing peak demand by the assumed 10-year growth in generation as a percentage of current demand (as per National Grid's Seven Year Statement).

The source of the generation forecast will need to be defined in more detail by those DNOs that adopt the common FCP approach.

- The total new generation forecast is subdivided into generation forecasts for each voltage level on the assumption that each voltage level will retain its existing proportion of total embedded generation on the network.

- Each voltage level's generation forecast is divided by the size of the generation (MW) actually attached to that level in the test-size generator power flow analysis. The calculated figure is taken to be the probability that a test sized generator will connect at that voltage level. So, for example, if 3,000MVA of generation is attached to the 33kV network as part of the test-size generator analysis, but only 600MVA of generation is actually forecast for the network over the next 10 years, then the probability of a test-size generator connecting to the 33kV network is taken to be 600/3,000 = 0.2.

1.22. Forecasting total EHV generation over the next 10 years - As described above, the methodology determines the probability that a test-size generator will be connected to a Network Group within the next 10 years. It is assumed that there is an equal probability of connection in each of the 10 years. This gives a linear function of the amount connected multiplied by the probability of connection rising from zero, at time zero, to the test-size at the end of the 10 years.

1.23. This assumption of linear generation growth implies that reinforcement will be required at:

$$Y = 10H/S_v$$

Y = time to reinforcement
H = initial headroom
S_V = generator test-size

1.24. Total generation over the 10-year recovery period will be:

$$10\left(G + S_v\ / 2\right)$$

G = initial generation level.

1.25. *Derive £/kVA/annum charges* – Calculate preliminary £/kVA/annum charges for EHV generation by spreading forecast reinforcement costs across total expected EHV generation for the 10-year period. For a specific network group, the FCP generation charge is derived from the following formula:

$$FCP_{generation} = AP_v \exp(-iY) / 10(G + S_v \; / \; 2)$$

i = the discount rate, which is assumed to the pre-tax cost of capital set by Ofgem as part of the price control
A = reinforcement cost associated with the connection of a test size generator
P_V = is the probability of a test-size generator connecting
Y = time to reinforcement
G = initial generation level
S_V = generator test-size

1.26. The numerator is the discounted expected reinforcement cost and the denominator represents total EHV generation over 10-year period.

Generation benefits

1.27. The addition of generation to the network can reduce the requirement for network reinforcement due to increases in demand. The generation benefit corresponds to the extent to which generation is considered to contribute to a reduction in demand when assessing system security at each voltage level.

1.28. Generation benefits are calculated by summing all of the demand costs for voltages and transformation levels at and above the point of connection, multiplied by the P2/6 Generation Contribution Factor. The benefits of connecting generation are taken to include the benefits of all voltage levels above the point of connection up to the highest level at which generation can contribute to network security.

1.29. The calculation of generation benefits should be considered and, if required, developed further by those DNOs that adopt the common FCP approach.

Scaling

1.30. The charges described above are scaled by calculating a single fixed adder (£/kVA) in the following way:

- A target income that relates to EHV assets is calculated by taking the total allowed revenue and splitting it by the proportion which the EHV modern equivalent asset value (MEAV) comprises the total network MEAV.

- The total revenue recovered from FCP demand and generation EHV charges is deducted from the EHV target income to give a residual value. This is then divided by the total EHV kVA to give a £/kVA value which is incorporated into customers' final tariffs.

1.31. The detail around scaling is to be developed by those DNOs selecting the FCP approach.

Derivation of final EHV charges

1.32. Final demand and generation charges are a combination of the relevant charges described above plus any other qualifying costs, e.g. sole use asset charges and transmission exit charges.

1.33. The detail around the calculation of these other costs is to be further developed by those DNOs selecting the FCP approach.

1.34. Scaled FCP demand and generation charges are recovered as a capacity charge (£/kVA):

- The demand capacity charge is equal to the FCP_{demand} charge (£/kVA) plus the fixed adder (£/kVA) and any other qualifying costs.
- The generation capacity charge is equal to the $FCP_{generation}$ charge (£/kVA) minus any generation benefit (£/kVA).

1.35. Sole use assets charges are charged for in a fixed charge (£/year) and comprise a charge for assets that would otherwise be paid for in the upfront connection charge. The fixed charge for each EHV customer is determined as follows. Where outstanding costs for sole use assets exist, the fixed charge is calculated by determining a charge over the nominal life of the assets (typically 40 years) through a charge comprising of: i) depreciation calculated on a straight line basis from the gross asset value of the outstanding sole use assets and ii) a return on capital calculated from the depreciated value of the asset(s) and the cost of capital.

1.36. The detail around the calculation of sole use asset charges should be further clarified by those DNOs selecting the FCP approach.

Interaction with the CDCM

1.37. The final EHV charges described above will recover a proportion of total EHV allowed revenue. The remainder is passed down into the CDCM.

1.38. This remainder is allocated to HV and LV customers in accordance with the CDCM covering charges to customers at these lower voltages.

1.39. The detail of this interaction should be developed by those DNOs that adopt the common FCP approach.

Charges to IDNOs

1.40. Independent distribution network operator (IDNO) charging arrangements should be developed by DNOs working with IDNOs.

Appendix 3 – Glossary

A

Authority

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

C

CDCM – Common Distribution Charging Methodology

The CDCM is the name given to the common methodology for HV/LV charging to be developed and submitted by the DNOs on or before 1 September 2009 for approval by the Authority under standard licence condition 50.

CMG – Common Methodology Group

The CMG was established by the DNOs in late Autumn 2008 under the auspices of the Energy Networks Association. The CMG has undertaken the development of a common methodology and governance arrangements for HV/LV charging.

D

DCUSA – Distribution Connection and Use of System Agreement

The DCUSA is an industry code which governs connection and use of system arrangements between DNOs, suppliers and some generators on the distribution networks.

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

EDCM – Extra High Voltage Distribution Charging Methodology

The EDCM is the collective name given to each of the two common methodologies for EHV charging to be developed and submitted by the DNOs on or before 1 September 2010 for approval by the Authority under proposed standard licence condition 50A.

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 typically consisting of a voltage level of 22kV or more.

H

HV/LV – High/Low Voltage
Term used to describe the parts of the distribution networks typically at a voltage level of less than 22Kv.

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.

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 4 – 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.[1]

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[2].

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[3];
- 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.[4]

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:

[1] entitled "Gas Supply" and "Electricity Supply" respectively.
[2] 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.
[3] 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.
[4] The Authority may have regard to other descriptions of consumers.

- promote efficiency and economy on the part of those licensed[5] 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[6] 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.

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

Appendix 5 – 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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