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# Electricity distribution structure of charges: the common distribution charging methodology at lower voltages

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

**Overview:**

Distribution network operators (DNOs) have a licence requirement to implement a common charging methodology for charges at lower voltages and to introduce open governance arrangements for the common methodology by 1 April 2010. This document sets out our decision on the common methodology at lower voltages following consultation earlier this autumn. We have decided to approve the methodology subject to a small number of conditions. The approval has effect from 31 December 2009 and the new arrangements and associated charges will apply from 1 April 2010.

This decision incorporates details on the conditions we are applying to approval of the methodology and DNOs have 28 days to make representations on these conditions. As part of our DPCR5 final proposals document we will publish updated illustrative charges for 1 April 2010 taking into account the new price control allowances and the DNOs' best view of the new charging models that will apply from April 2010. These charges are expected to be close to the final prices for April 2010.

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## Context

This document sets out our decision to approve the electricity distribution network operators' (DNOs) common charging methodology at lower voltages subject to a small number of conditions. Delivery of the electricity distribution structure of charges project is a priority for Ofgem. Given the levels of investment DNOs are forecasting on their networks between 2010 and 2015 and the challenges the networks will face as we move to a low carbon economy it is important we do all that we can to ensure charging arrangements are cost reflective.

In October 2008 and March 2009 we set out our decisions concerning the charging methodology we expect to be implemented at lower voltages. In July 2009 we introduced a licence obligation on DNOs to implement a common use of system charging methodology and open governance arrangements at lower voltage levels on the distribution networks for 1 April 2010. DNOs now also have an obligation to implement one of two common use of system charging methodologies at the higher voltage levels by April 2011. We have worked closely with the DNOs in developing these proposals and the DNOs consulted on their proposals during the summer. As the electricity distribution price control review (DPCR5) is happening in parallel, the introduction of the new charging arrangements will coincide with new revenue allowances for the DNOs on 1 April 2010.

## Associated Documents

- Electricity distribution structure of charges project: Distribution Network Operators' proposals for a common methodology at lower voltages, 114/09, September 2009

- Electricity Distribution Price Control Review Initial Proposals, 92/09, August 2009

- DNO Report on the Draft Common Distribution Charging Methodology, August 2009: http://2009.energynetworks.org/storage/CDCM%20Submission%20Documents%20August%202009.zip

- DNOs' populated common charging models, August 2009: http://2009.energynetworks.org/storage/CDCM%20Models.zip

- 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

- 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 ..... 1**
**1. Electricity distribution structure of charges project context ..... 3**
Progress on the structure of charges project ..... 3
Approval of the CDCM subject to conditions ..... 6
Areas for further development ..... 8
Derogations ..... 8
Structure of this document ..... 9
**2. Our decision ..... 10**
Implementation of CDCM in full from April 2010 ..... 10
Approval subject to conditions ..... 11
Areas for further development ..... 15
**Appendices ..... 18**
**Appendix 1 - CDCM consultation questions and responses ..... 19**
**Appendix 2 - Direction to approve the CDCM and Notice of approval of the CDCM subject to conditions ..... 33**
**Appendix 3 - Network unavailability rebate payments: wording to appear in the CDCM ..... 37**
**Appendix 4 - Brief overview of the CDCM ..... 38**
**Appendix 5 - The Authority's Powers and Duties ..... 40**
**Appendix 6 - Glossary ..... 42**
**Appendix 7 - Feedback Questionnaire ..... 46**

## Summary

This document provides our decision on the electricity distribution network operators' (DNOs') formal proposals for distribution charging at lower voltages. We set out the reasons for our decision in Chapter 2. The DNO proposal represents a significant milestone in the structure of charges project and we are approving the common charging methodology subject to a number of conditions with effect from 31 December 2009. In our last consultation we set out three conditions we thought should be attached to the approval of the methodology. Having reviewed responses to that consultation we have incorporated more conditions aimed at making improvements to the methodology for charging independent DNOs (IDNOs).

The structure of charges project aims to deliver more cost reflective, common and more transparent charging methodologies along with open governance arrangements. Customers are expected to benefit from the project through lower expenditure on the networks, lower supplier cost in managing a variety of methodologies and improved choice by facilitating competition from IDNOs. More cost reflective charging is very important for customers. DNOs expect to make high levels of expenditure (around £1.5bn to £2bn of load related reinforcement investment) over the 2010 to 2015 period to reinforce the network where capacity is tight and demand is growing. Some of this expenditure could be avoided if charges directed customers away from congested parts of the network and reflected the lower cost of using those parts of the network where there is surplus capacity.

More cost reflective charging is also important in the move to a low carbon economy, in ensuring that local generation, off peak use and energy management are properly rewarded where they avoid the need for network reinforcement. We think it is important that the new charging arrangements are introduced on 1 April 2010 so that low carbon developments and customers in general can begin to reap these benefits as soon as possible.

The new methodology the DNOs have brought forward has a significant one off impact on the distribution charges to some customer groups. In general across the country, as a result of the methodology distribution charges will increase slightly to domestic unrestricted customers and will increase more substantially to half hourly high voltage (HV) customers; charges will decrease to non-domestic non-half hourly demand customers and will become negative to generation customers. We note that tariff changes vary widely across DNOs and the impact of the proposed changes on specific customer groups is in some cases significantly higher than the average.

Earlier this year, in our consultation, we set out to estimate the impacts of the proposed methodology based on the output of the DNOs' charging models at that time. We also estimated the likely combined impact on charges of the new charging methodology and the new price control arrangements for the 2010 to 2015 period (DPCR5), based on our initial price control proposals. Since then, we have seen some significant changes in the 1 April 2010 price increases the DNOs expect as a result of the new price control arrangements and anticipate some change in the outputs of the charging methodology when it is updated on a 2010/11 basis. We recognise that the degree of uncertainty around the final charges is of concern to suppliers and

customer groups. We intend to publish the DPCR5 Final Proposals on 7 December when we will provide an updated view of the impact of the price control and the charging methodology on distribution charges per customer group. Revenues will change as a result of the new price control which will have an impact on the level of customer charges. Many DNOs have assured us that they are doing all they can to keep interested parties informed of the likely changes to use of system charges.

We have carefully considered the responses to our consultation document and particularly those from a number of suppliers who argued we should seek to phase in or delay introduction of the new charging arrangements. We think that suppliers have had adequate warning that there would be price disturbance on 1 April 2010 as a result of the new charging methodologies. We note that a number of suppliers, including those in niche markets, have taken steps to mitigate the impact of increases in the distribution charges they will face. We think that delaying the introduction of the new arrangemnets would forestall the benefits and that a turn around in a policy that has been signalled well in advance would disadvantage those suppliers who have adopted contracting and other strategies in anticipation of changes to the distribution charges.

The DNOs have worked together since autumn 2008 on common charging arrangements at the lower voltage levels. Their charging models are available to view on the Energy Network Association's website[1]. Whilst the models are detailed, their publication has enabled interested parties to understand the modelling behind the proposed method.

We provide a summary of our conditional approvals in Table 1 to this document. We are minded to take enforcement action or consult on witholding DPCR5 allowed revenue of up to 0.5% if these conditions are not addressed in the timescale provided, i.e. by 31 December 2009 for some conditions. We set out in Table 2 areas where we consider the methodology should be further developed and improved over time through open governance arrangements. We have updated our views on both of these matters having reviewed responses to our proposals, and we explain the reasons for these changes. Also the DNOs' proposal assumes that the price control does not limit how much revenue is recovered from demand customers on the one hand and from generation customers on the other. This does not reflect current price control arrangements. Our decision to approve the common methodology is therefore contingent on our new (DPCR5) price control Final Proposals decision regarding revenue pots and this decision taking effect.

New open governance arrangements will mean that industry parties can bring forward proposed changes to the common methodology. This is an important development and should mean that the methodology is refined and adapts to changes in the networks over time. These new governance arrangements will be implemented via a change to the Distribution Connection and Use of System Agreement (DCUSA) and will require changes to the function of the distribution charging methodology forum (DCMF). This move to open governance is broadly consistent with the aims of our wider review of industry governance arrangements, for which our final proposals will be published early in the New Year.

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

# 1. Electricity distribution structure of charges project context

**Chapter Summary**

In this chapter we set out the background to the DNOs' work on a common methodology at lower voltages and the context of the decisions contained in this document. We summarise our decisions in tabular form and explain the structure of the remainder of this document.

## Progress on the structure of charges project

*Background*

1.1. On 25 August 2009 distribution network operators (DNOs) submitted their common charging methodology to the Authority for approval in respect of use of system charges at lower voltages, specifically charges at high (HV) and low voltages (LV). This is in line with licence condition 50 of the electricity distribution licence which requires the DNOs to bring forward common UoS charging arrangements by 1 September 2009 for implementation from 1 April 2010.

1.2. In September we consulted on our minded to position to approve the common distribution charging methodology (CDCM). The majority of respondents welcomed the move to a common methodology and open governance arrangements. Respondents generally viewed the methodology as sound, and its cost reflectivity an important step toward a low carbon economy. However, suppliers in particular raised concerns regarding the large impact on charges that the methodology will bring about with some arguing that these changes could disadvantage niche suppliers in particular. Other respondents have raised concerns on the reliability, transparency and stability of model inputs. We discuss our response to these concerns in Chapter 2 and in Appendix 1.

1.3. The DNO methodology is the culmination of a number of years' work to ensure the charging regime remains fit for purpose. Changes to the charging arrangements are required to reflect a number of developments. Importantly, we need to ensure that the DNOs do not over charge low carbon or energy saving initiatives such as distribution connected generation (DG) and moves to manage the timing of electricity use. This is important given the move to smart metering and we note that special off-peak heating tariffs are falling in the majority of DNOs' areas which may help to encourage the uptake such meters.

1.4. DNOs also need to ensure that the charging arrangements do not unfairly stand in the way of independent network operators (IDNOs) competing against them to provide network extensions. Finally, with the sharp increase in the level of expenditure by DNOs on reinforcing their networks it is more important than ever that charges signal to customers where there is spare capacity on the network and where an increase in electricity load may lead to significant further expenditure.

*Stakeholder engagement*

1.5. Through the project we have encouraged DNOs to engage with their customers. The DNOs have invited stakeholders to participate in work stream meetings on the project and held a workshop on their proposals in June. Following the publication of DNOs' consultations on their proposed methodologies and models at lower voltages in June and July we published an open letter flagging[2] that the combination of this project along with the new DPCR5 price control could have a significant impact on charges to some customer groups and requesting the DNOs to do all they can to keep interested parties informed of the likely change in charges. We have been assured by many of the DNOs that they are doing all they can to keep interested parties informed of the likely changes to use of system charges.

1.6. We provided an updated open letter in September[3] to highlight our consultation on the CDCM and to set out the DNOs' strategies for communicating the impact of this project and the price control with their customers. In this letter we urged DNOs to provide for forums such as workshops, teleconference seminars and one to one meetings with industry parties where they have not already done so. All DNOs have either now held or are planning to hold customer workshops or teleconferences, and the feedback we have had is that these have been very useful.

1.7. Once the new charging arrangements are in place, the DNOs will have a continuing role in explaining their methodology to interested parties, bearing in mind that the methodology is complex and may not be easy to understand from a cursory examination of the model and that other parties need to understand the methodology if they are to participate in the open governance arrangements.

*Impact on charges*

1.8. Distribution charges are generally less than 20% of the final electricity bill for the customer. The new methodology though, does have a signficant one off impact on distribution charges to some customer groups. In general across the country, as a result of the methodology distribution charges will increase to domestic unrestricted customers and will increase more substantially to half hourly high voltage (HV) customers; charges will decrease to non-domestic non-half hourly demand customers and will become negative to generation customers. Generally the proposals will provide and increase the margins available to IDNOs on small and medium sized developments which could be expected to further open these sites to competition and potential benefits that IDNOs can bring.

[2] Available on our website at
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=488&refer=Networks/ElecDist/Policy/DistChrgs.

[3] Available on our website at
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx.

1.9. Tariff changes vary widely across DNOs and the impact of the proposed changes on specific customer groups is in some cases significantly higher than the average. Variation across DNOs is due in part to the fact that the impact of the move to a common methodology will depend on the starting position of each DNO. The rest of the variations are explained mainly by the improved cost reflectivity of the new model. The charge for a customer reflects the cost of supplying electricity to a customer. This cost will vary depending on customer characteristics (such as its coincidence factor) giving rise to different charges to different customers, and due to different topographies and demographics across DNOs, giving rise to different charges across DNOs.

1.10. In our consultation we set out to estimate the impacts of the proposed methodology based on the output of the DNOs' charging models at that time. We also estimated the likely combined impact on charges of the new charging methodology and the new price control arrangements for the 2010 to 2015 period (DPCR5), based on our initial price control proposals. Following our price control update on 5 October we revised and republished these tables on our website[4]. Since then, we have seen some significant changes in the 1 April 2010 price increases the DNOs expect as a result of the new price control arrangements and in the outputs of the charging methodology.

1.11. We recognise that the degree of uncertainty around the final charges is of concern to suppliers and customer groups. We have asked the DNOs to provide their best view of their charging models on a 2010/11 basis and we will consider these models alongside price control parameters. We intend to publish the DPCR5 Final Proposals on 7 December when we will be in a position to provide an updated view of the impact of the price control and the charging methodology on distribution charges per customer group. This will provide more reliable illustrative charges for 2010/11 based on final allowed revenues and the best view from the DNO on its charging model on a 2010 basis, including each company's forecasts of 2010/11 consumptions and their under/over recovery positions. We would not expect the DNOs' December indicative charges to be very different from these illustrative charges, though we recognise the position on revenue recovery may change slightly between mid November and late December.

1.12. We consider that the new common methodology represents a more cost reflective way to allocate each DNO's regulatory allowed revenue among customers so that customers that impose more cost on the network pay more. Aside from changes in revenue driven by the new price control, the methodology is revenue neutral and, as noted above, some customer categories will benefit, just as some will face higher charges as a result.

[4] See our website at: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/8Oct09%20IA%20update.pdf.

## Approval of the CDCM subject to conditions

1.13. Standard licence condition 50 requires the DNOs to bring forward a common charging methodology which they believe is capable of approval by the Authority. The CDCM, as submitted to us on 25 August, constitutes the DNOs' proposals for a common methodology. This approval constitutes a formal direction under 50.18 of the DNOs' distribution licence. We set out the reasons for our decision in Chapter 2.

1.14. Since autumn 2008 the DNOs have been working with us and other stakeholders to implement an approach broadly in line with our October 2008 and subsequent March 2009 decisions[5]. In our October 2008 and subsequent documents we have stressed that our decisions were intended to provide the DNOs with a starting point for their work, and that the methodology would necessarily need to improve and evolve both through further work by DNOs and ongoing common governance arrangements. The decisions specifically noted areas where the DNOs would need to do further work prior to submission to us, for example in respect of the form of final tariffs. We also noted that the approach to charging IDNOs would need to be developed by DNOs working with IDNOs and we have facilitated specific work groups to this effect.

1.15. Following the introduction of the licence requirement on DNOs to implement a common methodology at lower voltage levels from 1 April 2010, the licence specifies that the Authority may or may not approve the DNOs' proposals for implementation in April 2010, or approve them subject to conditions.

1.16. DNOs have made good progress towards a common method and we have decided to approve the DNOs' CDCM proposals against the relevant objectives[6] set out in licence condition 50 subject to a small number of conditions. In approving the CDCM we consider that when tested against the relevant objectives the common method provides:

[5] Available on our website at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx, document ref 135/08 (October 2008 decision) and 24/09 (March 2009 decision).

[6] The Relevant Objectives are set out in the licence as:

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

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

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

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

- a cost reflective baseline that more effectively takes account of the benefits that generators can provide to the distribution network (SLC 50.8);
- improvements to generator charging and charges to IDNOs that are in response to the development of DNOs' networks (SLC 50.9); and
- more transparency which we anticipate will facilitate competition in supply and generation (SLC 50.7).

1.17. We have considered consultation responses in coming to our decision, and following responses we have added areas for conditional approval in respect of charges to IDNOs. Whilst we are broadly happy with the methodology in respect of charges to IDNOs, we are concerned that in a few areas the CDCM does not adequately reflect costs and that this in turn could distort competition. These conditions require further specific work in a specific timescale, and we detail our decisions in Chapter 2. We summarise our conditional approvals in Table 1 below.

1.18. The DNOs' CDCM submission assumes that there is no restriction on the portion of allowed revenue that is recovered from demand and generation customers. The special licence conditions that underpin the 2005-2010 (DPCR4) price control place restrictions on the revenue that is recovered from these two categories of users. This decision to approve the CDCM is therefore contingent on our Final Proposals decision and this decision taking effect. Our Final Proposals for DPCR5 will set out our decision to allow for the CDCM to take effect via the removal of the single revenue pots at lower voltages. Implementation of the decision regarding revenue pot arrangements under the CDCM will require changes to the special licence conditions concerning generation revenue and demand revenue prior to 1 April 2010. If a DNO rejects our Final Proposals then we will still need to seek to change the special licence conditions to allow the CDCM to come in to effect from 1 April.

1.19. In our consultation we were minded to conditionally approve the use of service models in the CDCM due to inconsistencies in the application of service models for generation. These inconsistencies have now been addressed by the DNOs involved (Scottish Power Energy Networks (SP) and EDF Energy Networks (EDF)) and the materiality of this change in terms of impact on charges is minimal. This is therefore no longer a condition of our approval.

**Table 1 - summary of conditional approvals under the CDCM**

| Conditional approval | Timescale for work | Document paragrah |
|---|---|---|
| Generation charging in generation dominated areas | 1 Sept 2010 | 2.10-2.14 |
| Network unavailability rebate payments | 31 Dec 2009 | 2.15-2.17 |
| IDNO charging - generation tariffs | 31 Dec 2009 | 2.23-2.24 |
| IDNO input data | 31 Dec 2009 | 2.25-2.30 |
| IDNO charging - HV split | 31 Dec 2009 | 2.31-2.33 |

## Areas for further development

1.20. We have reconsidered areas for further development following our consultation. A summary of our final views on these areas is provided in Table 2 below.

**Table 2 - summary of further work required by DNOs, predominantly under open governance arrangements**

| Further work required by DNOs | Document paragraph |
|---|---|
| Commonality of the network (500MW) model | 2.34 |
| Standing charge factors | 2.35 |
| Reactive proxy data | 2.36 |
| Justification of the non-scaling of generator charges | 2.37-2.38 |
| IDNO charging - allocation of cost to HV connected IDNOs with LV end users | 2. 39-2.41 |
| Input data standardisation and provision of greater information | 2.42-2.43 |

1.21. In Chapter 2 we discuss these areas for development through open governance arrangements. The issue around IDNO charging regarding HV connected IDNOs with LV end users is new and reflects responses to our consultation. A number of areas for further development have been omitted from the table above as they have been either:

- made conditional approvals (in the case of the three IDNO approvals subject to conditions). The reasons for this are set out in Chapter 2; or
- addressed already (in the case of splitting out operating expenditure in the model); or
- responses have convinced us that the area does not need to be flagged by us for further work (for example in the case of our concerns over voltage of supply vs voltage of connection). The reasons for our views are set out in Appendix 1.

## Derogations

1.22. The licence allows a DNO to seek derogations from the common approach, for example where DNOs cannot implement the changes in billing systems in time for implementation in April 2010. DNOs have now submitted their derogation requests, which we have published on our website[7]. A summary of derogation requests is provided in Table 3 below. We have discussed these requests with DNOs, IDNOs and suppliers and anticipate issuing our decisions on them in December. In making these decisions we will bear in mind the impact any derogations will have on obtaining the full and early benefit to customers of these new charging arrangements.

[7] See our website at: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/Cover_for_CDCM_submission_and_derogations.pdf.

**Table 3 - summary of DNO derogation requests: we will issue separate decisions on these requests**

| DNO group | Brief description of derogation request(s) | Requested duration |
|---|---|---|
| CE Electric | - Reactive power charging<br>- Excess capacity charging | 1 July 2010<br>1 July 2010 |
| Central Networks | - Request to allow legacy arrangement<br>- Reactive power charging | Indefinite<br>31 March 2011 |
| Electricity North West | - Excess capacity charging<br>- Billing on p/day basis | 30 Sep 2010<br>30 Sep 2010 |
| EDF Energy Networks | - Reactive power charging<br>- Excess capacity charging<br>- Generator charging<br>- Billing on p/day basis<br>- Billing in clock time | 30 Sep 2010<br>30 Sep 2010<br>31 March 2011<br>30 Sep 2010<br>31 March 2011 |
| ScottishPower Energy Networks | - Reactive power charging<br>- Excess capacity charging | 1 Apr 2011<br>1 Apr 2011 |
| SSE Power Distribution | - No derogation requests submitted | - n/a |
| Western Power Distribution | - IDNO portfolio billing<br>- De-energised MPANs<br>- Reactive power charging<br>- Excess capacity charging | 1 Oct 2010<br>1 Oct 2010<br>1 Oct 2010<br>1 Oct 2010 |

## Structure of this document

1.23. Chapter 2 sets out our decisions on the DNOs' common methodology submission and the full implementation of the CDCM from 1 April 2010.

1.24. Appendix 1 summarises responses to this consultation and provides our views on the comments made. Appendix 2 replicates the formal direction and notice sent to the Company Secretary of each DNO under licence condition 50 concerning the approval of the CDCM subject to conditions. Appendix 3 sets out the wording to apply in the CDCM in respect of one of our conditions. For reference, Appendix 4 sets out how the CDCM works at a high level.

# 2. Our decision

**Chapter Summary**

In this chapter we set out our decisions and provide our thinking on the conditional approvals that will apply to the common methodology. We also set out our decision to apply the methodology in full from April 2010 and comment on areas for further development in light of consultation responses. Appendix 1 provides more detail on responses to our consultation and our views on these responses.

2.1. Our decision is to approve the DNOs' CDCM proposals against the relevant objectives subject to the conditions detailed below. We have also decided that the methodology should apply in full from April 2010. We set out the reasons for our decisions below.

## Implementation of CDCM in full from April 2010

2.2. The new charging methodology will have a large impact on distribution charges for some customer categories in particular as it comes in conjunction with DPCR5. In our consultation we indicated that we were minded not to phase in the implementation of the methodology but rather implement it in full in 1 April 2010. We sought views on this 'minded to' decision. We received mixed responses which are summarised in Appendix 1.

2.3. Some suppliers argued that we had not given sufficient consideration to the impact that the full introduction of the charging arrangements on 1 April 2010 would have on retail competition. This argument applies particularly to niche suppliers that might see a significant increase in distribution charges if they do not have a diversified customer base and who may not be able to pass through the charge disturbance to customers due to contractual restrictions. There were also concerns around the uncertainty of charges given the interaction with price control allowed revenue final proposals and the impact on customers.

2.4. We have looked carefully at the arguments put forward by those who think we should phase in or delay the implementation of the new charging methodology. We think all suppliers had sufficient warning that the new charging methodology would come in to effect from 1 April 2010. Through our documents, for example our March 2009 decision on the project and the subsequent change to the distribution licence effective from July 2009, the steps we have taken and the efforts of the DNOs, suppliers have been left in no doubt that the new charging arrangements were likely to be coming into effect. While suppliers and other users have not known the exact materiality of these changes, we think that suppliers were able to take into account the potential tariff disturbance expected on 1 April when entering into contracts this summer and autumn.

2.5. We view that suppliers, including niche suppliers serving the non-domestic market could have sought to protect themselves from this impact and uncertainty by reducing their exposure to fixed price contracts by reducing the proportion of fixed term contracts (even though this may have disadvantaged them in securing contracts) or by introducing provisions to pass through distribution charges to the end customer. A number of suppliers, including those in niche markets, have taken steps to mitigate the impact of increases in the distribution charges they will face. We think that if we delay the implementation of the CDCM there is a risk that we will reward those suppliers that did not factor in the uncertainty around distribution prices and disadvantage those that have made arrangements, which would itself potentially distort retail competition.

2.6. We note also the impacts of these changes on end customers. We think there will be significant benefits to the new charging arrangements to all network users in environmental and economic terms and it is important to implement them sooner rather than later, particularly bearing in mind the time it has taken to deliver more cost reflective generator charging and charges to IDNOs. The arguments for phasing have not dissuaded us from this intent hence our decision not to phase the implementation of the CDCM.

## Approval subject to conditions

2.7. The decision to approve the CDCM proposal is subject to five conditions as summarised in Table 1 to Chapter 1. Four out of these five conditions have a delivery date of 31 December 2009.

2.8. The CDCM will be subject to the new open governance arrangements. The high level arrangements are currently being progressed as a change to the DCUSA - the industry code which governs connection and use of system arrangements on the distribution networks, and a subsequent change will be required to insert the CDCM methodology in to the DCUSA. We consider that the timescale for delivery on the conditions will allow the CDCM, including delivery on the four conditions, to be incorporated in to the DCUSA by 1 April 2010.

2.9. With regards to conditional approvals, including those set for completion by 31 December 2009, we are minded to take enforcement action or consult on witholding DPCR5 allowed revenue of up to 0.5% if these conditions are not addressed in the timescale provided.

### Generation charging in generation dominated areas

2.10. In our CDCM consultation we noted that DNOs had not covered off the issue of how to charge generators where the network is generation rather than demand dominated. This was a requirement in our March 2009 decision document on the structure of charges project.

2.11. Six of seven DNO groups argue in their responses that they do not consider this area of work should be a conditional approval and that we have not been clear enough what is required to satisfy the condition.

2.12. We agree that the CDCM is an average charging model and that any move to distinguish demand and generation dominated areas presents certain issues for the CDCM, however we are keen that the DNOs think through this issue and the available options (which are not necessarily locational charging) more fully in order to deliver on the requirements of our March 2009 decision document. This will require them to develop - where appropriate - a charging method for generation dominated areas.

2.13. We note the amount of generation being forecast to connect to the DNOs' networks and we are concerned that the DNOs have not addressed this in their submissions to us. We consider that this remains a sufficiently important area of charging to warrant a formal conditional approval.

2.14. This condition should be met by 1 September 2010.

**Network unavailability rebate payments**

2.15. We view it as good practice to have all relevant charging information for the customer in a single charging methodology and maintain our position that the network unavailability rebates scheme should be part of the CDCM. DNOs have argued for a separate charging statement to set out their network unavailability rebate payments. We consider that a separate charging statement will not be as transparent as including this in the methodology and the methodology remains a practical place to set out the rebate payments. For the avoidance of doubt, the scheme applies to generators connected at more than 1,000 volts (i.e. high voltage) where the generator has agreed a standard connection.

2.16. Our decision is for a conditional approval requiring the DNOs to insert the network availability rebate payments in to the CDCM, per our wording in Appendix 3. The wording of the appendix has been amended following consultation responses to clarify that unavailability payments apply only to customers with a standard connection to the distribution system. This amendment is underlined in Appendix 3.

2.17. This condition should be met by 31 December 2009.

**IDNO charging**

2.18. In the CDCM consultation we highlighted three areas where we would like to see some further work undertaken which might result in methodological changes. These were: IDNO boundary tariffs for generators connected to their network; inputs into the IDNO CDCM model; and the HV split. We are pleased to note that some progress has been made in all of these areas especially in relation to generation tariffs. However, whilst progress has been made on the other two, they have not yet been fully resolved.

2.19. Our decision in relation to IDNO charging aspects of the CDCM is to issue a condition on final approval of the CDCM for each of these three areas. For the areas of CDCM IDNO model inputs and the HV split this conditional approval provides the DNOs with clarity as to what further work is required from them and what methodological changes are required to facilitate the incorporation of this work in the CDCM. In the case of generation tariffs, where we understand that the DNOs have agreed to adopt tariffs that are consistent with the position that we outlined in the consultation document, a conditional approval is the best way of expediting the inclusion of this methodological change in the CDCM.

2.20. As set out above, if by 31 December the IDNO charging conditions have not been met then we are minded to consider enforcement action or to proceed to a consultation on the need for, and scale of, withholding of DPCR5 revenue.

2.21. We have considered the responses to the CDCM in coming to our decision. These responses are summarised and our views are presented in Appendix 1. The responses did not alter our view that overall the CDCM is a reasonable framework for IDNO charging or that the areas outlined above needed further work.

2.22. We have, partly as a result of the responses received, identified a further area where we consider the methodology could be improved. This area is the discount applied to DNO end user charges to derive IDNO charges for customers connected (to the IDNO network) at LV where the IDNO connection to the DNO network is at HV. This issue is related to the concerns that we expressed in the consultation with regard to the HV split, namely that there needs to be an appropriate allocation of HV cost to IDNOs where they connect to the DNO HV network. DNOs should be mindful of as they consider their obligations not to restrict, distort or prevent competition in distribution. This is an issue that we consider should be dealt with without delay under the open governance process of the CDCM. We consider this further in the 'Areas for further development' section of this chapter.

*IDNO generation tariffs*

2.23. In our consultation document we stated that "It may be inappropriate for IDNOs to pay the fixed charge element of end user generation charges to the DNO". The DNOs have indicated that they are in agreement with this statement and their proposed solution is to offer IDNO generation tariffs a zero percent discount on the unit charge and a 100% discount on the fixed charge. We have made the adoption of this as part of the CDCM a condition of our approval. As we note above we have issued a conditional approval with regard to this because this is the best way to facilitate this change to the methodology.

2.24. This condition should be met by 31 December 2009.

*IDNO input data - consistency and appropriateness of input data across DNOs*

2.25. In our consultation we highlighted that there were some concerns with the consistency of input data used to populate the CDCM IDNO models. In particular we have highlighted the areas of unit cost assumptions used in the underlying data and also the use of forecast business plan (FBPQ) questionnaire data as potential areas of concern. We further identified the outcomes of the model with regard to the three EDF companies indicated that there is a particular issue with the inputs that EDF used.

2.26. After reviewing responses, and further work undertaken by EDF, we consider that the specific requirement of the methodology to use FBPQ data to evidence the net capital expediture (capex) and modern equivalent asset (MEAV) cost drivers used in the CDCM IDNO model can prevent appropriate representation of these cost drivers. This is in part due to the different underlying assumptions used by companies used to populate the FBPQ and in part to the (to some extent necessary) selective use of capex data from the FBPQ.

2.27. We have therefore made it a condition of our approval of the CDCM to remove the specific references to FBPQ data in the methodology. The references are made in paragraphs 183 ((a) and (b)), 185 and 187 in the DNOs' August 2009 Report on the Draft Common Distribution Charging Methodology which was formally submitted to us on 25 August. These references restrict the use of alternative data where the imperfections of the FBPQ data lead to concerns over the outputs of the model. They also provide a barrier to the use of more up to date and consistent data (such that produced from Ofgem's initial and final proposals) being used to populate the model in the medium term.

2.28. This conditional approval clearly does not remove the obligations of the DNOs to robustly evidence the cost drivers that they use in the CDCM IDNO model. Further, when evidencing the cost drivers the DNOs should clearly bear in mind their obligations not to restrict, distort or prevent competition in distribution. Any data used to evidence the cost driver should be clearly auditable and verifiable. Furthermore the DNOs should review the data that they use to evidence these cost drivers as new data becomes available. In addition as FBPQ, Initial Proposals and Final Proposals data (which appear to the most reliable – prospective in the case of Final Proposals - sources of data at this time) relate to a distinct time period the DNOs will need to proactively consider what data they will use when we move towards the end of the period.

2.29. The conditional approval does not lead to a requirement for all DNOs to use alterative inputs to FBPQ data in the short term (prior to the charging year 2010). However DNOs should consider what data they use in the short term taking into account their obligations not to restrict, distort or prevent competition in distribution.

2.30. This condition should be met by 31 December 2009.

*IDNO charging - HV split*

2.31. In the CDCM consultation we stated that. "We do not consider that the current HV splits proposed by the DNOs appropriately reflect the usage of a DNO's network by HV connected IDNOs". Through the DNO/IDNO working group[8] the DNOs are discussing amongst themselves the appropriate way of determining the HV split. This has involved, amongst other things, compiling the evidence on the utilisation of the DNO HV network by HV connected IDNOs (in terms of distance of main) across all DNOs. This work is not yet complete.

2.32. We have made it a condition of the approval of the CDCM that the DNOs bring forward a robustly evidenced HV split which leads to an appropriate allocation of HV cost to HV connected IDNOs. The DNOs should consider their obligations not to restrict, distort or prevent competition in distribution when evidencing the HV split.

2.33. This condition should be met by 31 December 2009.

## Areas for further development

### Commonality of the network (500MW) model

2.34. The design of the network model and the split of assets across network levels is a key driver of customer charges. It is crucial, therefore, that it is done in a consistent and cost reflective manner across licensees. The DNOs have developed guidance containing a set of principles and instructions that all DNOs should follow when developing the 500MW network model[9]. While this guidance is a good beginning, we expect that further work towards commonality on the principles guiding the network model should be taken up by the industry under open governance arrangements.

### Standing charge factors

2.35. The DNOs propose to use 'standing charge factors' to determine the extent to which voltage level costs are recoverable through capacity or fixed charges. The choice of standing charge parameters has a strong impact on charges as they determine the balance between unit and fixed/capacity charges. We are not convinced that the parameter values in the CDCM are well founded and given their materiality we consider that this matter should progress further under open governance arrangements.

[8] Minutes of the DNO and IDNO steering group are available on our website at: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/IDNOs/Pages/IDNOs.aspx.
[9] The guidance is included in a document entitled "Manual for the Draft Common Distribution Charging Methodology Model", August 2009 (see section entitled "Guidance on asset models"), available on the Energy Network Association's website at http://2009.energynetworks.org/structure-of-charges.

**Reactive proxy data**

2.36. The CDCM presents a new method for reactive power charging. The proposed method is more demanding in terms of data requirements and where data is not available for a network level, data at the nearest network level at which it is available should be used as a proxy. The use of proxy data appears adequate, however this could be further refined by DNOs to ensure the use of actual data at each network level. We would expect DNOs to consider this matter further through open governance arrangements.

**Justification of the non-scaling of generator charges**

2.37. A bottom-up charging methodology requires a mechanism to scale charges to match the recovered revenue from the model with the permitted price control revenue. The DNOs decided to exclude generators from the revenue matching process, meaning charges/credits to generators remain at their pre-scaling level.

2.38. The proposal does not provide any justification for the decision to exclude generators from scaling and we would expect this matter to be addressed through open governance arrangements. We see no obvious reason why DGs should be excluded from this mechanism.

**Allocation of cost to HV connected IDNOs with LV end users**

2.39. Related to the issue of the HV split, which is concerned with the allocation of HV network cost to HV connected IDNOs we have also identified the allocation of HV cost to HV connected IDNOs with LV end users as an area of concern. We feel that this is an area that the DNOs should be mindful of with regard to their obligations not to restrict, distort or prevent competition in distribution. This is an issue that we feel can be dealt with without delay under the open governance process of the CDCM.

2.40. Under the methodology as it stands there is only a facility for allocating cost for the LV and HV/LV parts of the DNO network to HV connected IDNOs with LV end users. The CDCM report states that for HV connected IDNOs

> 205. The percentage discount applicable to tariffs for LV network end users is:
>
> [HV: LV discount] = [LV allocation] + [HV/LV allocation].

2.41. This does not allow for any allocation of cost with regard to the HV to HV (as opposed to HV/LV) connected IDNOs with LV end users. We do not consider that this is appropriate. It is not always the case that the IDNO connects directly into the HV/LV substation. Where IDNOs connect to the HV system it would seem appropriate that some HV cost should be allocated to the IDNO (thereby increasing the IDNO discount). Furthermore there is a portion of the HV cost that is classified as indirect cost under the methodology, i.e. costs that do not vary with the scale of network activity. These costs are more likely to vary with the numbers of customers supplied by the network provider. It would therefore seem appropriate that HV connected IDNOs with LV end users should receive an allocation of these indirect costs as they are supplanting the need for the DNO to service many end users with a single user. An allocation of HV direct and indirect cost to HV IDNOs with LV end users would also bring their treatment within the CDCM into line with that of HV connected IDNOs with HV end users.

**Input data standardisation and provision of greater information**

2.42. DNOs have taken significant steps forward over the transparency of their models. However, respondents to our consultation as well as to the DNOs' consultations commented that more detail is required regarding the inputs to the model. There were also concerns that a number of CDCM inputs (e.g. coincidence factors) can fluctuate and have large effect on charges.

2.43. We believe inputs, and the method for deriving them, should be defined in a more transparent manner and it should also be clear how often such inputs are revised. It is also important to ensure commonality in the derivation of inputs and to consider whether standardisation of certain assumptions within the method across DNOs would be appropriate in certain circumstances. While we do not want to remove appropriate differences across DNOs' network areas (DSAs), it is not clear clear that large variations to the industry average or median in, for example, input costs, are appropriate. We expect this issue to be followed up using open governance arrangements.

# Appendices

**Index**



| Appendix | Name of Appendix | Page Number |
|---|---|---|
| 1 | CDCM consultation questions and responses | 19 |
| 2 | Direction to approve the CDCM and Notice of approval of the CDCM subject to conditions | 33 |
| 3 | Network unavailability rebate payments: wording to appear in the CDCM | 37 |
| 4 | Brief overview of the CDCM | 38 |
| 5 | The Authority's Powers and Duties | 40 |
| 6 | Glossary | 42 |
| 7 | Feedback Questionnaire | 46 |

# Appendix 1 - CDCM consultation questions and responses

1.1. In our September consultation document ('Electricity distribution structure of charges project: DNOs' proposals for a common methodology at lower voltages', reference number 114/09) we sought the views of respondents in relation to any of the issues set out in the document as well on a number of specific questions as set out below:

**CHAPTER Two**

**Question1:** Do you agree with our minded to positions given the arguments / analysis presented here and in the Impact Assessment in Appendix 3? If not, why not?
**Question2:** Do you consider any additional areas should be conditionally approved?
**Question 3:** Do you consider any element of the methodology would warrant an overall vetoing of the DNOs' common methodology submission?
**Question 4:** Are there any additional areas you would like to flag as areas you consider warrant further work by DNOs in the future?

## List of Respondents

| List | Name |
|---|---|
| 1 | British Gas |
| 2 | CE Electric (CE) |
| 3 | Central Networks (CN) |
| 4 | Consumer Focus |
| 5 | EDF Energy Networks (EDF) |
| 6 | Energy Networks Association |
| 7 | Electricity North West (ENW) |
| 8 | ESP Electricity |
| 9 | GDF Suez |
| 10 | Renewable Energy Association |
| 11 | RWE npower |
| 12 | Scottish Power Energy Networks (SP) |
| 13 | Scottish Power Energy Retail Limited |
| 14 | Scottish and Southern Energy (SSE) |
| 15 | Western Power Distribution (WPD) |

## Summary of Responses

1.2. We received 15 non-confidential responses to our September consultation. Responses which were not marked as being confidential have been published on Ofgem's website www.ofgem.gov.uk. Copies of non-confidential responses are also available from Ofgem's library.

1.3. The following is a summary of those responses which were received, together with our view on the issues raised in the responses. Responses are grouped by subject. Our decisions are summarised in Chapter 2 above.

**Approval subject to condition concerning generation charging in generation dominated areas**

1.4. The DNOs argue that the requirements under this condition are not clear. In particular, they are not clear whether Ofgem expects them to implement locational charges or whether to employ a different averaging approach to the method. DNOs argue that clarity is required over the definition of 'generation dominated' networks, noting that different conclusions would potentially be obtained depending on whether the installed generation capacity in every substation is considered or whether the installed capacity is corrected by the typical load factor of the generation. They note that another approach to this issue would examine how many substations actually experience 'reverse flows' to higher voltage levels during the year.

1.5. Six DNOs (ENW excluded) believe that it would be preferable that this area is not identified as a condition for the approval of the CDCM, but suggest this issue should instead be dealt with under open governance arrangements. They indicate that they would take this issue forward in time for the implementation of EHV charging methodologies in April 2011. CN suggests that it would be more appropriate to make approval of the CDCM conditional on the DNOs raising the issue within the open governance arrangements. CE flags that DNOs may not be able to deliver an optimal solution to this issue due to restrictions of the settlement system (not disaggregating by geographic location).

1.6. ENW is concerned about the lack of clarity over the requirements of the condition and says that the short time limit for the condition is inadequate for a comprehensive review of the issue.

1.7. The REA maintain that given the non-locational nature of the model, and given that generators are credited only for the benefit they provide above their voltage of supply, an assumption that the network is demand dominated is appropriate. They argue that even if a network is generation dominated, treating generators that operate in such areas differently without also given extra credit to generators that operate in areas where they provide more than average benefit appears to be a one-sided application of cost reflective charging.

*Our view*

1.8. We note concerns over the practicality of determining generator charges at lower voltages on a locational basis. We require the DNOs to further justify their position using quantitative data and qualitative arguments around the options for charging, which are not necessarily locational. We note that the key issue to resolve whilst there is an average model is how the 'average' situation is determined and when this approach is no longer appropriate. We consider that the timeframe provided for work to develop a generator charging methodology, where appropriate, is adequate.

**Approval subject to condition concerning network unavailability rebate payments**

1.9. Six of the DNOs argue that network unavailability rebates are not related to use of system revenue or charging and therefore would be better covered in a separate statement. They argue that if network unavailability rebates are included within the CDCM there is a potential for duplication and inconsistencies in the statements.

1.10. EDF adds that the network unavailability rebates scheme is a price control and not a CDCM matter. They suggest that the price and calculation are agreed between the DNO and Ofgem, but if these are placed in the CDCM they can be changed using open governance and this places an increased risk on the DNO. EDF requests that the condition be removed given the small materiality of the issue.

1.11. CE asserts that the scheme is a price control matter but concedes that it was included within DNOs' charging methodologies in 2005 as a pragmatic alternative to inclusion within the licence. Nonetheless they propose that the scheme be put into a separate statement from the CDCM. CE seeks clarity from Ofgem on the generators to which the scheme is applicable since our consultation document did not distinguish between standard and non-standard connection agreements.

*Our view*

1.12. While the scheme is set up under the price control, we view it as good practice to have all relevant charging information for the customer in a single charging methodology and maintain our position that the network unavailability rebates scheme should be part of the CDCM. A separate statement, as suggested by most DNOs, would not be as easily accessible as the CDCM. We are therefore retaining this as a condition of our approval and provide the wording to go in the CDCM in Appendix 3 to this document.

**Service models**

1.13. In our consultation we were minded to conditionally approve the use of service models in the CDCM due to inconsistencies in the application of service models for generation. The DNOs' collective response, submitted by the Energy Networks

Association, responded that SP and EDF they can readily address the issue and correct the inconsistencies identified and that they would work to ensure commonality. EDF responded that they have already addressed the issue and incorporated it into their recent submission of April 2010 illustrative charges.

*Our view*

1.14. The DNOs' collective response to the consultation confirms that the inconsistencies in the application of service models to generator charging have been addressed by the DNOs. This issue therefore no longer requires a conditional approval.

**Splitting out operating expenditure in the model for greater transparency**

1.15. In our consultation we indicated that the transparency of the model can be improved if the operating expenditure entry was split into direct costs, indirect costs and network rates. The DNOs' collective response set out that there is no issue with incorporating this suggestion into the model.

*Our view*

1.16. The DNOs' collective response confirms this is an easy issue to rectify and we understand that the DNOs models now achieve this and will be published with this split.

**Voltage of connection/voltage of supply**

1.17. In our consultation we noted that, in the context of generation charging, our October 2008 decision used the term 'voltage of connection', as is used in the connection charging methodology, while the CDCM refers to the 'voltage of supply'. We said that we would expect that the definition of voltage of connection in the connection charging methodology would apply to use of system arrangements and that we expect the issue to be resolved through open governance arrangements.

1.18. The DNOs responded that the use of the term 'voltage of supply' was deliberate and appropriate. The voltage of supply may, albeit on the odd occasion, differ from the voltage of connection. They argue that in the context of generator charging, it is appropriate to consider the voltage of supply for the purpose of determining the benefits that generators provide to the network.

1.19. The DNOs note that neither the term 'voltage of connection' nor 'voltage of supply' is used in the distribution license or in the DCUSA. They propose to change the term 'voltage of supply' to 'entry point' or 'exit point' (as appropriate), in line with the terminology in the license and DCUSA.

*Our view*

1.20. We accept the DNOs' explanation and agree that voltage of supply is appropriate in the context of generation charging. With regard to changing the terminology in accordance with DCUSA, we think this change would add clarity prevent confusion.

**CDCM inputs, including potential for volatility of charges**

1.21. British Gas notes that the CDCM assumes a fixed rate of return of 6.9% while this rate should probably change according to price control. They also maintain that while they support the removal of fixed cost from the model, the position of operating costs considered fixed, currently 26.5%, should be subject to open governance arrangements.

1.22. RWE believe substantially more detail is required with regard to the 500MW network model, including the process for deriving the inputs, disclosure of data sources, reference periods and assumptions made. They argue that transparency over the nature of inputs is crucial to assure commonality, especially for inputs with a large potential impact on charges, such as the input to the 500MW network model and load profile data. SSE is concerned that a number of CDCM inputs can fluctuate and have large effect on charges. EDF note the need to work on improving the guidance and information provided on inputs to the model.

*Our view*

1.23. It does not appear entirely appropriate that the rate of return in the CDCM accords to the rate of return for the 2005-2010 (DPCR4) price control period. The industry may like to consider this matter further.

1.24. We agree that more work is required on ensuring DNOs' 500MW models are built on common and transparent principles. The same point applies to inputs to the model. These issues are noted in Table 2 to Chapter 1 and we expect them to be progressed via open governance arrangements.

**Exceeded capacity**

1.25. EDF believe that the issue of excess capacity charges has not been properly addressed in the CDCM. They argue for an alternative method of calculating excess capacity charge and request that Ofgem make inclusion of such method a conditional approval. ENW is disappointed with the current CDCM method for calculating excess capacity charge and from the fact that Ofgem has not picked up on it in their consultation. ENW flags this issue as an area of further work and propose that it is dealt with through the open governance process.

*Our view*

1.26. We consider the current approach to be fit for purpose. Parties who are unhappy with the CDCM can suggest changes under open governance arrangements.

**Other issues**

1.27. EDF argues that the number of tariff bands for generators is inadequate. They say that a single rate for intermittent generation may send the wrong economic signal by rewarding output when the output is not benefiting the network and that having only three rates for non-intermittent generation means that generators operating at system peak do not receive the correct benefit.

1.28. With respect to the new approach for reactive charges, EDF argues that while it is a good starting point, it fails to provide strong enough incentives to reduce reactive power consumption.  They seem to suggest that reactive unit rates should be a function of the customer's power factor.

*Our view*

1.29. The DNOs consulted on their proposed method for reactive power charging and generally received positive responses on their proposal.  However, EDF can discuss potential changes of approach under open governance arrangements.

**Phasing of CDCM implementation**

1.30. Our consultation indicated that the move to CDCM entails some significant illustrative impacts on charges for some customer groups.

1.31. SSE and E.on indicated that they support phasing the implementation of the CDCM.  SSE argue that a full implementation in April 2010 will have deleterious effect on supply competition.  The main suppliers at risk, they argue, are the ones serving the non-domestic HV sector.  They claim that large increases in DUoS charges may wipe out a supplier's profitability and put the supplier in a competitive disadvantage.  SSE recommends delaying the implementation until April 2011 or phase in new charging methodology by introducing a cap on the impact.

1.32. British Gas argues against phasing.  They say that several rounds of consultation should have made the charge changes well understood by stakeholders and that the benefits of the CDCM (e.g. in terms of transparency) should be introduced in full as early as feasible. Comments from a number of suppliers suggest they did take in to account the project at an early stage.

*Our view*

1.33. Our view on the issue of phasing the implementation of the CDCM and on the arguments raised in the responses is provided in Chapter 2 to this document.

**Derogation requests**

1.34. Following the submission of the CDCM proposals we received derogation requests from 6 DNOs. The requests are summarised in Table 3 to Chapter 1. We have published all DNOs' derogation requests on our website. Three suppliers commented on these requests.

1.35. E.on argued that given the long timescale of the project DNOs should have anticipated the required system changes and implement them in a timely manner, just as E.on did and that if derogations are granted suppliers will have to implement changes in a piecemeal fashion. SP Energy Retail expect DNOs to have either system updates in place or manual work-around ready for all areas of the CDCM by 1 April 2010 since they consider that derogation will have detrimental impact on them. They suggest that in order to limit this impact that where derogations are granted, a uniform deadline that coincides with use of system publication dates (i.e. 1 April and 1 October) be given as on these dates suppliers are resourced appropriately.

1.36. SP Energy Retail also point out that derogations will detract from the benefit of the CDCM by having suppliers contend with a mixture of old and new charging arrangements. Under a certain derogation where a group of customers will not be charged under CDCM, it may obstruct supply competition for this customer group.

1.37. Npower want to see a transparent process over the removal of the derogations. They emphasise the importance of clear communication and proposes to follow the DCUSA pattern for bi-annual standard price changes for the removal of derogations, with the associated notice periods. They also suggest a monthly update detailing progress against derogations and the risk of slippage across all DNOs. Npower also argue that we should make sure that customers are not ‘over-charged’ under derogation relative to the enduring solution so that the process of removal of derogations is made easier.

*Our view*

1.38. As the suppliers acknowledge, implementation of the CDCM involves substantial IT and billing system changes. We are currently investigating derogation requests. For each derogation we will explore the reason for the derogation, the impact on suppliers, the environment, competition and customers. We will endeavour to facilitate clear communication regarding the process of removal of derogations and provide clarity to stakeholders as early as we can.

**Treatment of pre-2005 generators at lower voltages**

1.39. In our consultation on the CDCM we set out that the CDCM applies to all distributed generators. EDF agree that the application of CDCM HV/LV use of system charges will apply to all HV/LV connected generators from April 2010.

1.40. CE also set out that the CDCM applies to all HV/LV use of system charges and agree that there should be no discrimination between generators connected pre and post 2005. They state that it is not, however, clear whether or not this same approach should be applied to extra high voltage (EHV) customers, given that the common methodologies for EHV are not anticipated to be implemented until April 2011. They also question how price control demand and generation allowances will to be split if these two groups of customers are to be treated differently.

*Our view*

1.41. It is for DNOs to ensure they are not discriminating in how they charge generators, notwithstanding the charging methodology in place. It is clear that the CDCM as submitted applies to all HV/LV generators from 1 April 2010.

## IDNO Issues

**LV IDNO margins available under CDCM**

1.42. A number of respondents (all IDNOs from which five responses were received) disagree with Ofgem’s analysis that the CDCM results in improved IDNO margins at IDNO sites with domestic end users. These respondents claim that the overall investment opportunity for IDNOs based on the CDCM margins will deny the opportunity for an efficient IDNO to operate profitably. These respondents also point out that for the most part the margin that they are able to make at sites they currently operate will fall under the CDCM charges.

1.43. Two respondents (partially) based their claim that the CDCM charges will reduce the overall investment opportunity available to IDNOs on evidence from the distribution of sites that they have bid to adopt in the gas distribution market.

1.44. Some respondents commented that the claimed erosion of IDNO margins was evidence that the CDCM method allocates more cost to the higher network tiers than the DNOs existing charging methodologies.

1.45. One respondent suggested that the evidence on current margins that was presented in the consultation document was misleading and suggested that the impact of the CDCM on IDNO margins was less favourable than was in fact the case.

*Our view*

1.46. In this document we have issued a conditional approval of the CDCM with respect to the charging of HV connected IDNOs. We have also indicated an area where we would expect to see progress made, again with respect to the charging of HV connected IDNOs, under the open governance process of the CDCM. We believe that with these changes to the methodology CDCM IDNO charges will increase the range of investment opportunities available to IDNOs. This should increase competition for the adoption of domestic customer sites.

1.47. Overall the impact of the CDCM will be that margins at larger IDNO sites (in terms of the number of domestic plots) will tend to fall but margins at smaller sites will tend to increase. The changes in margins are reflective of the unwinding of the practice of charging IDNOs under a commercial tariff. Both IDNOs and DNOs have acknowledged that charging IDNOs using a commercial tariff was not cost reflective.

1.48. Our observation that the CDCM will improve the overall investment opportunity for IDNOs has drawn on evidence regarding the range of investment opportunities available to IDNOs. This evidence largely consists of data for all UK planning applications over the period January 2005 to March 2008. In their responses two IDNOs put forward alternative evidence for IDNO opportunities. Their evidence was based on portfolio of sites that they had bid to adopt in the gas distribution market. This evidence covered a significant time period and a very large number of sites. The IDNO evidence indicated that the opportunities included a greater number of large domestic sites than was indicated by the planning applications data. This proportion of large sites has implications for assessing the impact of CDCM because at large sites IDNO margins tend to fall.

1.49. We have considered the alternative evidence put forward by these IDNOs. However, we consider that the planning application data is a more reliable indicator of the distribution of new domestic development site sizes. We believe this to be the case because the structure of gas tariffs means that Independent Gas Transporters (IGTs) will earn significantly larger margins at larger sites and will therefore be strongly incentivised to peruse opportunities at these sites more vigorously. Therefore the gas portfolio data can be expected to contain a higher weighting of larger sites than the population of investment opportunities.

1.50. We do not consider that DNOs have shifted costs towards the higher network tiers. DNOs and IDNOs agree that charging IDNOs using a commercial tariff is not cost reflective because most IDNO end users are domestic customers. Therefore any comparison between the IDNO margins provided by the CDCM tariffs, which recognise this fact, and those provided by commercial tariffs cannot be interpreted as clear evidence that the former represents a reallocation of costs. Changes in margins are more likely indicative of a switch to more cost reflective tariffs. If anything the evidence is to the contrary of a movement of cost to the higher network tiers. The charges to domestic customers, all of which connect to the lower network tiers, have increased under the CDCM (compared with what they would have been under existing DNO methodologies). This suggests that within the CDCM more cost is allocated to the lower network tiers.

1.51. With regard to the evidence presented on existing IDNO margins in the CDCM consultation we note the difference between these and the margins put forward by one respondent to the consultation. The margins put forward in the consultation were based on data submitted by DNOs as part of the process of introducing interim IDNO charges. We note that the disparities appear to mainly be caused by differences in assumptions regarding the boundary tariffs that would be applied to IDNO sites, required capacity at sites and units consumed at sites. We are not in a position to make judgments regarding the assumptions made. However we consider that the exact position will not be exactly captured by either the assumption put forward by either the DNOs or this respondent. Furthermore, we consider that this issue will not alter our overall conclusions regarding the CCDM methodology.

**HV IDNO margins available under CDCM**

1.52. Most IDNO respondents commented that the HV IDNO margins produced by the CDCM were lower than the existing margins for HV connected IDNOs and are inappropriate. One respondent commented that the margins at their current HV sites fall by 40%.

*Our view*

1.53. We flagged in our consultation document that the calculation of the HV split required further work by the DNOs. We have made completion of this work a condition of the approval of the CDCM. We have also highlighted that we would expect to see changes to the basis for calculating the IDNO discount (from end user charges) under the CDCM open governance process.

1.54. In their responses IDNOs indicated particular concern regarding the prospective margins for HV connected IDNO sites with LV end users outlined in Table 11 of the consultation document. In Table 4 below we present illustrative analysis of the potential impact of changes (along the lines we have outlined in this document) to the CDCM with regard to the calculation of the discount for HV connected IDNOs with LV end users (HV to LV discount). In Table 4 we set out the HV to LV IDNO margins that were originally presented in the CDCM consultation document. We also present prospective margins if all indirect cost allocated to the HV network level by the CDCM IDNO model was incorporated in the IDNO discount. In addition we present illustrative margins if in addition to HV indirect cost the IDNO discount incorporated respectively 10% and 20% of HV direct cost.

**Range of IDNO margins across DNO areas**

1.55. Most of the IDNO respondents questioned the robustness of the CDCM IDNO method due to the wide range of outputs (IDNO margins) produced. One respondent said that the range of margins seriously questioned the ability of DNOs to determine the notional costs of operating a downstream business using this methodology. Unfavourable comparison was made between the variability in margins implied by the CDCM and that experienced by some of the IDNOs in other sectors where they operate businesses. These sectors included gas, telecoms and water.

**Table 4: Illustrative impact of changes to the calculation of the HV to LV discount**

| DNO | Illustrative CDCM IDNO HV to LV margins | | | |
|---|---|---|---|---|
| | From CDCM consultation (1) | (1) + all indirect HV cost (2) | (2) + 10% of HV direct cost (3) | (2) +20% of HV direct cost (4) |
| CN West | £ 26.52 | £ 28.03 | £ 28.99 | £ 29.95 |
| CN East | £ 23.46 | £ 24.46 | £ 25.86 | £ 26.98 |
| ENW | £ 31.12[1] | £ 34.12 | £ 34.70 | £ 35.81 |
| CE NEDL | £ 33.65 | £ 35.78 | £ 36.63 | £ 37.78 |
| CE YEDL | £ 29.45 | £ 30.90 | £ 32.07 | £ 33.07 |
| WPD Wales | £ 40.27 | £ 47.17 | £ 49.02 | £ 51.12 |
| WPD West | £ 43.40 | £ 49.65 | £ 50.75 | £ 52.46 |
| EDF LPN | £ 19.22 | £ 22.51 | £ 21.06 | £ 21.92 |
| EDF SPN | £ 19.94 | £ 22.88 | £ 23.71 | £ 25.00 |
| EDF EPN | £ 17.25 | £ 19.84 | £ 20.23 | £ 20.94 |
| SP Distribution | £ 39.94 | £ 48.90 | £ 47.66 | £ 50.13 |
| SP Manweb | £ 37.88 | £ 43.93 | £ 43.42 | £ 45.44 |
| SSE Hydro | £ 37.20 | £ 52.06 | £ 54.24 | £ 57.07 |
| SSE Southern | £ 32.86 | £ 37.71 | £ 39.83 | £ 41.18 |

Source: Ofgem analysis of CDCM Models, based on 2009/10 allowed revenue.
[1] Note: the ENW HV margin was incorrect in our original CDCM consultation document (relevant parties have since been notified of the error and informed of the corrected value).

*Our view*

1.56. We acknowledge that there may be areas where the consistency of the input data may be improved. Improvements in the consistency of the input data would most likely lead to a reduction in the variability of IDNO margins produced by the CDCM.

1.57. Areas where data consistency might be improved might include the unit cost assumptions underlying some of the companies FBPQ data and MEAV calculations. Indeed the use of FBPQ data (which appeared to be the best available at the time) might itself be superseded by more accurate (and consistent) forecast capex data included in the companies initial and/or final proposals.

1.58. We do not envisage (beyond EDF – see below) that other DNOs would need to make significant adjustments to their input data prior to April 2010. However this is an area where changes could be made under the open governance process. As we explain above we would expect the DNO to fully consider whether there is a need to incorporate more up to date input data in the model in the medium to long term.

1.59. Our observations of the CDCM IDNO margins showed that the margins produced by EDF are clear outliers compared with those produced by other DNOs. It is our view that the EDF situation is a result of the input data that they have used rather than any issue with the methodology. We flagged the issues of EDF's margins in our consultation document and EDF have been working with us to resolve any issues surrounding their input data. We expect these issues to be resolved prior the finalisation of charges for April 1 2010. Furthermore, the conditional approval surrounding the input data used in populating the CDCM IDNO model effectively requires them to do this.

1.60. With regard to the margins put forward by the other DNOs there remains substantial variation. Taking the example of the LV domestic customers IDNO margins (excluding EDF) vary between £17.34 and £32.31 (or by 86%). However we have noted that margins are much larger for those companies that have higher 'All The Way' charges and all of these companies would appear to be companies whose DSA contains a larger proportion of rural customers. It would appear that there is a reasonable explanation for a substantial proportion of the variation in margins, namely that the higher margins tend to be in more rural network.

1.61. Networks with a greater proportion of rural customers are likely to require greater network length per customer and therefore distribution services are likely to cost more per customer. For the companies that we might consider to have more rural networks (SP Distribution/Manweb, SSE Hydro/Southern, WPD Wales/West) margins vary between £27.61 and £32.31. For the set of companies whose networks that we might consider to be a greater mix of urban and rural (CN East/West, NEDL/YEDL, ENW) the margins vary between £17.34 and £24.97. Viewed like this the variation in margins appears to be much less significant.

1.62. We note the comments that the CDCM margins display greater variation than margins available for comparable activity undertaken in other sectors. We consider that this comparison is one that should be borne in mind, however such comparisons cannot be made directly because of the differing circumstances in these sectors. For example in the most directly comparable sector (gas) the cost data that underpins the allocation used to derive boundary charges for IGTs is, unlike the CDCM, averaged across all gas distribution networks (GDNs). To some extent this is as a consequence of the fact that until fairly recently all GDNs (unlike DNOs) were under common ownership.

**IDNO generation tariffs in the CDCM**

1.63. One respondent commented that the CDCM risks undermining the development of embedded generation to achieve the governments low carbon objectives. The main reason given for this is that the generation credits brought into force by the CDCM do not accurately capture the implied upstream cost saving made by the DNO due to the presence of distributed generation offsetting demand.

1.64. The same respondent further commented that the proposals allow DNOs to recover the costs of transporting units to the IDNO boundary which were not in fact required due to the presence of generation on an IDNO site.

*Our view*

1.65. We do not accept that the CDCM undermines the development of embedded generation. For the first time, embedded generators will receive a credit to reflect the benefit they can provide in deferring reinforcement on the network levels above the point of connection. This credit is based on the average economic benefit provided by the generators with regard to reducing the requirement for upstream reinforcement.

1.66. It is appropriate that the credit for the economic benefit provided by generation goes to the party that creates it, i.e. the generator. IDNOs, however, as we made clear in our consultation, should be able to earn a margin that would allow them to cover reasonable local network costs. The adoption of the condition regarding IDNO boundary charges for generation will permit an IDNO to earn a gross margin equivalent to local network (service model) costs that a generator would impose on the DNO.

1.67. One IDNO respondent suggests that the generation credits do not accurately reflect the deferred upstream reinforcement costs. They present some detailed analysis to back up this observation. However, we do not consider that the analysis demonstrates that the generation credits underestimate upstream reinforcement cost savings to the DNO. This is because it relies on approximating the deferred reinforcement cost by flexing the IDNO boundary charge by the number of units that would be produced by a generator. This approximation assumes that there is equivalence to the average cost savings induced by of one less unit of domestic demand on a DNO network and by one more unit of generation on the network. This is not the case. The CDCM allocates cost (which in the case of generation is negative reflecting the benefit they provide) to customer groups on the basis of their coincidence factors (which represent the coincidence of the customer load with peak network usage). These estimates are based on a combination of evidence regarding the DNOs' own network flows and engineering judgement. For all DNOs the coincidence factor of domestic customers is greater than that of generators, hence the average benefit (cost saving) of one less unit of domestic demand is greater than that of one more unit of generation.

1.68. The respondent further notes that there will be a difference between the units billed at the boundary for an IDNO site and the units that the site imports when there is distributed generation at the site. This is true, but the end user charges levied by the IDNO will also do the same (including cost allocated to the user for the higher network tiers) whether the customer is on an IDNO site with generation or not. The margin earned by IDNOs for each demand customer will be the same whether there is any embedded gernation or not at and IDNO site.

1.69. Both the boundary and user charges are average charges, calculated conditional on forecast levels of distibuted generation. Therefore in calculating the demand charges (and in the determination of IDNO demand margin) the contribution of distributed generation to reducing upstream reinforcement cost is taken into account.

1.70. The CDCM charges to demand users and to generators reflect the cost that they impose on the DNO's network on average. The IDNO charges for demand and generation reflect an allocation of that cost that is attributable to the activities undertaken by the IDNO (instead of the DNO) on average.

# Appendix 2 - Direction to approve the CDCM and Notice of approval of the CDCM subject to conditions

**Direction pursuant Standard Licence Condition 50.18 of the Electricity Distribution Licence to approve the Common Distribution Charging Methodology subject to conditions**

**Notice pursuant Standard Licence Condition 50.20 of the Electricity Distribution Licence to approve the Common Distribution Charging Methodology subject to conditions**

Whereas

**1.** Standard Licence Condition 50 ("SLC 50") of the electricity distribution licence (the "Licence") requires a Common Distribution Charging Methodology ("CDCM") to be developed and brought into force by Distribution Service Providers[10] on 1 April 2010.

**2.** Pursuant to SLC 50.15 the Distribution Services Providers submitted the CDCM to the Authority for approval on 25 August 2009.

**3.** The Authority has carefully considered the CDCM and the responses received in relation to its consultation dated 28 September 2009[11].

**4.** Pursuant to SLC 50.18 the Authority, having regard to its principle objective and duties under the Electricity Act 1989 (the "Act"), proposes to approve the CDCM subject to conditions, for the reasons set out it its decision document (Electricity distribution structure of charges: the common distribution charging methodology at lower voltages)[12] dated 20 November 2009 on the basis that it achieves the Relevant Objectives[13].

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[10] Distribution Service Providers are licensed electricity distributors in whose electricity distribution licence the requirements of section B of the standard licence conditions have effect.

[11] Electricity distribution structure of charges project: Distribution Network Operators' proposals for a common methodology at lower voltages, 114/09, September 2009.

[12] This can be obtained from Ofgem's website at www.ofgem.gov.uk.

[13] The Relevant Objectives are set out in SLC 50 as:

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

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

**5.** Pursuant to SLC 50.20 the Authority gives Notice that it proposes to approve the CDCM subject to certain conditions (the "Conditions") that require the Distribution Services Providers to undertake further action to ensure the CDCM would better achieve the Relevant Objectives.

**6.** Pursuant to SLC 50.20(a) the Conditions are set out in Annex 1 to this document. The Annex sets out the nature and contents of the Conditions and, pursuant to SLC 50.19(b), the time by which such action should be completed.

**7.** Pursuant to SLC 50.20(b) the Distribution Services Providers have until **18 December 2009** to make any representations or objections in respect the Conditions.

**Now therefore**

In accordance with the powers contained in SLC 50 of the Licence, the Authority hereby approves the CDCM subject to the Conditions and gives Notice of those Conditions.

**This constitutes notice pursuant to section 49A of the Act**

…………………………………………………

Rachel Fletcher - Partner, Distribution
For and on behalf of the Authority
20 November 2009

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

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

**Annex 1**

The reasons behind the Authority's decision to apply conditions are as follows:

The methodology behind generation tariffs for Independent Distribution Network Operators ("IDNOs"):

In our consultation document we stated that "It may be inappropriate for IDNOs to pay the fixed charge element of end user generation charges to the DNO". The DNOs have indicated that they are in agreement with this statement and their proposed solution is to offer IDNO generation tariffs a zero percent discount on the unit charge and a 100% discount on the fixed charge. We have made the adoption of this as part of the CDCM a condition of our approval. We have issued a conditional approval with regard to this because this is the best way to facilitate this change to the methodology.

This condition should be met by 31 December 2009.

The methodology behind the calculation of HV tariffs for IDNOs:

In the CDCM consultation we stated that "We do not consider that the current HV splits proposed by the DNOs appropriately reflect the usage of a DNO's network by HV connected IDNOs". For this reason we have made it a condition of the approval of the CDCM that the DNOs bring forward a robustly evidenced HV split which leads to an appropriate allocation of HV cost to HV connected IDNOs. The DNOs should consider their obligations not restrict, distort or prevent competition in distribution when evidencing the HV split.

This condition should be met by 31 December 2009.

The use of input data used to produce tariffs for IDNOs:

We have made it a condition of our approval of the CDCM to remove the specific references to Forecast Business Plan Questionnaire (FBPQ) data in the methodology. The references are made in paragraphs 183 ((a) and (b)), 185 and 187 in the DNOs' August 2009 Report on the Draft Common Distribution Charging Methodology which was formally submitted to us on 25 August.

We have made our decision because these references restrict the use of alternative data where the imperfections of the FBPQ data lead to concerns over the outputs of the model. They also provide a barrier to the use of more up to data and consistent data (such that produced from Ofgem's initial and final proposals) being used to populate the model in the medium term.

The conditional approval does not lead to a requirement for all DNOs to use alterative inputs to FBPQ data in the short term (prior to the charging year 2010). However DNOs should consider what data they use in the short term taking into account their obligations to not restrict, distort or prevent competition in distribution.

This condition should be met by 31 December 2009.

The methodology for generator tariffs in generation dominated areas:

Our March 2009 decision document[14] sets out that the methodology for generator charging will apply in the case of demand dominated network areas. The DNOs' CDCM submission to us does not explain what approach has been considered in respect of generation dominated areas and if and when such an approach might apply. We consider this is an omission from the submission.

We require the DNOs to develop - where appropriate - a charging method for generation dominated areas and to justify their position in order to deliver on the requirements of our March 2009 decision document. This will involve a consideration of the options for charging in generation dominated areas, which are not necessarily locational. We note that the key issue to resolve whilst there is an average model is how the 'average' situation is determined and when this approach is no longer appropriate.

This condition should be met by 1 September 2010.

The methodology in respect of network unavailability rebate payments.

The DNOs' CDCM submission to us does not cover network unavailability rebate payments. We consider this to be an omission from the CDCM. We require this to be inserted in to the CDCM, using the wording set out in Appendix 3 to our 20 November 2009 decision document on the CDCM.

This condition should be met by 31 December 2009.

[14] Next steps in delivering the electricity distribution structure of charges project, 24/09, March 2009.

# Appendix 3 - Network unavailability rebate payments: wording to appear in the CDCM

A compensation payment may be payable to customers for network outages under two schemes.

The majority of customers are compensated under the Guaranteed Standards arrangements set out in Statutory Instrument 2005 No. 1019 (The Electricity (Standards of Performance) Regulations 2005).

Customers who are off supply for greater then defined periods of time are entitled to a payment. This scheme applies to all demand customers and to all generators not included in the scheme described below.

For customers with generation connected at more than 1,000 volts <u>and who have agreed a standard connection</u> the following scheme will apply. This scheme is known as Distributed Generation Network Unavailability Rebate and payments will be calculated for each generator on the following basis:
Payment = A*B*(C-D)

Where:
A = the network unavailability price of £2 per MW per hour.
B = incentivised generator capacity; the highest active electrical power that can be generated (or the relevant incremental change of this amount in cases of the expansion of existing generation plant) by the generator for the year, according to the connection and/or use of system agreement(s).
C = network interruption duration; the total duration of all occurrences (in minutes) on the distribution system each of which involves a physical break in the circuit between itself and the rest of the system or due to any other open circuit condition, which prevents the generator from exporting power. It excludes:
- 50 per cent of the total duration of cases where the DNO takes pre-arranged outages of its equipment for which the statutory notification has been issued to the generator;
- the cases where the generator has specific exemption agreements with the DNO in the connection and/or use of system agreement(s); and
- the cases which are part of exempted events in the quality of service incentive or the Guaranteed Standard Statutory Instrument (such exemptions include interruptions of less than three minutes duration and industrial action).
D = the baseline network interruption duration for the relevant year which either has a default value of zero or some other value agreed between the customer and the DNO and recorded within either; the connection offer, connection agreement and/or use of system agreement(s).

Distributed Generation Network Unavailability Rebate scheme payments will be calculated by the network operator on an annual basis (1st April - 31st March) and payments made shortly after the end of each year. This payment is automatic and does not need to be claimed by the generation customer. The de minimis level of rebate is £5.

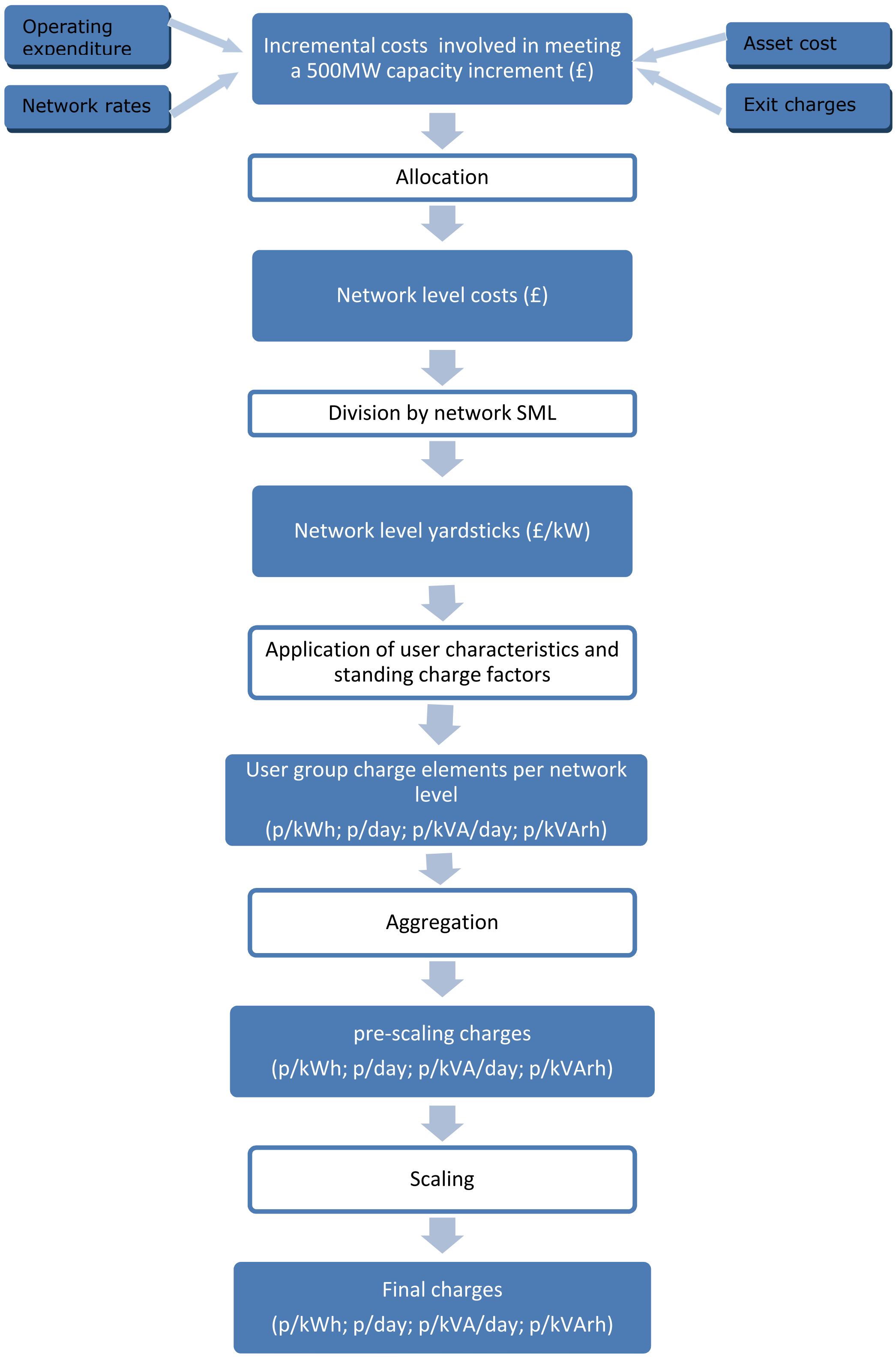
# Appendix 4 - Brief overview of the CDCM

1.1. This Appendix briefly sets out the process for deriving charges under the CDCM.

| |
|---|
| **Estimate the costs involved in meeting a 500MW increment in capacity**<br>▪ The (incremental) costs involved in meeting an increment in capacity are<br>▪ Asset costs; and<br>▪ Operating costs, network rates and a contribution to transmission exit charges[15].<br>▪ Asset costs are estimated through the construction of a network model. At each network level a notional network is designed to provide 500MW of simultaneous maximum load at the grid supply point. The assets of the notional models are costed in terms of their modern equivalent asset value and their cost is annuitised.<br>▪ Operating costs, network rates and exit charges are forecasts for the charging year. Forecasts are based on historical data coupled with the licensee's estimates of future trends. |
| **Allocate costs to network levels**<br>▪ Asset costs are allocated according to the network level of the assets<br>▪ Operating costs and network rates are allocated to each network level according to its share of modern equivalent asset value (asset replacement cost).<br>▪ Exit charges are allocated to the transmission exit level. |
| **Derive the yardstick cost of load at each network level (£/kW/year)**<br>▪ Divide network level costs by simultaneous maximum load at that level. This number will be different from 500MW due to loss and diversity adjustments. |
| **For each user, derive network level unit and standing charges based on user characteristics (e.g. coincidence factors) and agreed standing factors**[16]<br>▪ Unit charges are determined on the basis of the user's contribution to simultaneous maximum load (i.e. in reference to a coincidence factor).<br>▪ Capacity charges are allocated according to agreed capacity charge factors. Capacity charges apply only to half hourly customers (except unmetered supply).<br>▪ Fixed charges are allocated according to agreed fixed charge factors. |
| **For each user, aggregate the unit and standing charge elements across the applicable network levels. The charges obtained are the pre-scaled charges.**<br>▪ Applicable network levels include the voltage/transformation level of supply and all network levels above.<br>▪ Use pre-scaled charges and consumption forecast data to determine revenue shortfall/surplus relative to the regulatory allowed revenue. |
| **Scale charges up or down to match recovered revenue with allowed revenue. The charges obtained are the final charges.** |

[15] Transmission exit charges are levied on DNOs in respect of the costs of connecting the distribution network to the transmission network and represent a charge for specific connection assets at the interface between the transmission and distribution networks.
[16] Two of the tariffs (Related MPAN and unmetered supply customers) have only a unit charge component.

**Figure 1: Overview of the common distribution charging model**



# Appendix 5 - The Authority's Powers and Duties

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

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts[17].

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[18].

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[19];
- 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[20].

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:

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[17] entitled "Gas Supply" and "Electricity Supply" respectively.
[18] 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.
[19] 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.
[20] The Authority may have regard to other descriptions of consumers.

- promote efficiency and economy on the part of those licensed[21] 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[22] 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.

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

# Appendix 6 - Glossary

**A**

Authority

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

**C**

Common Distribution Charging Methodology (CDCM)

The common methodology for HV/LV charging as developed and submitted by the DNOs on 25 August 2009 for approval by the Authority under standard licence condition 50.

Customer Contributions

Upfront payments by customers for distribution services.

**D**

Distribution Connection and Use of System Agreement (DCUSA)

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

Distribution Charging Methodology Forum (DCMF)

Industry forum for discussion and development of distribution charging.

Distributed Generation (DG)

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 Great Britain.

Distribution Network Operators (DNOs)

A licensed distributor which operates electricity distribution networks in distribution service areas but can also compete to operate networks anywhere within Great Britain.

### Distribution Price Control Review 5 (DPCR5)

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 (DPCR4) will expire 31 March 2010. DPCR5 is planned to commence on 1 April 2010.

### Distribution Service Area (DSA)

As defined in SLC 1 of the electricity distribution licence.

**E**

### Electricity Act 1989

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

### Extra High Voltage (EHV)

Term used to describe the parts of distribution networks that are extra high voltage typically consisting of a voltage level of 22kV or more.

### EHV/HV

Level of transformation between extra high voltage and high voltage.

**F**

### Final Proposals

Ofgem's final proposals for DNO revenue allowances for the DCPR5 period.

### Forecast Business Plan Questionnaire (FBPQ)

Forecast Business Plan Questionnaires are submitted by DNOs as part of the DCPR5 process.  FBPQs contain the details of companies forecast expenditure over the period covered by the DCPR5 settlement.  The FBPQs also contain details of historic expenditure over the DCPR4 price control period.

**G**

### Grid Supply Point (GSP)

A Grid Supply Point is any point at which electricity is delivered from the National Electricity Transmission System to the DNO's Distribution System.

**H**

### Half hourly (HH) metered customers

Customers with a metering system which provides measurements on a half hourly basis for settlement purposes.

### HV – High Voltage

Term used to describe the parts of the distribution networks typically at a voltage level of less than 22kV, but greater than 1kV.

### HV/LV

Level of transformation between high and low voltage.

**I**

### Initial Proposals

Ofgem’s initial proposals for DNO revenue allowances for the DCPR5 period.

### Independent Distribution Network Operators (IDNOs)

A licensed distributor which does not have a distribution services area and competes to operate electricity distribution networks anywhere within Great Britain.

**K**

### kV

kilovolt.

**L**

### Low voltage

Term used to describe the parts of the distribution networks typically at a voltage level of less than 1kV.

**M**

### Modern Equivalent Asset Value (MEAV)

The cost of the network using current ('modern equivalent') assets and their associated current costs.

**N**

### Net Capital Expenditure (net capex)

The capital expenditure undertaken by DNOs (and IDNOs) less customer contributions. This approximates the amount of capital expenditure that is remunerated via UoS charges.

### Network tier/level

Sub-components of distribution networks can be categorised into network tiers or levels. These network tiers or level are distinguished by the voltage at which assets are operated, for example extra high voltage (EHV), high voltage (HV) and low voltage (LV).

**S**

### Standard Licence Condition (SLC)

These are conditions that licensees must comply with as part of their licences. SLCs are 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.

**T**

### Transmission exit charges

Transmission exit charges are charges paid by DNOs to National Grid (in its role as GB System Operator) for the financing and operating costs of the assets that connect the distribution network to the transmission network (the transmission exit point).

**U**

### Use of System (UoS) Charges

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

## Appendix 7 - Feedback Questionnaire

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

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

1.2. Please send your comments to:

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Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
andrew.macfaul@ofgem.gov.uk