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Electricity distribution charging methodologies: DNOs' proposals for the higher voltages

Consultation

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Overview:

Electricity distribution network operators (DNOs) were required under their licence to submit a common use of system charging methodology for higher voltage customers, that is capable of approval by the Authority, by no later than 1 April 2011. Should we approve the methodology, it would apply from 1 April 2012. Implementation of this charging methodology will be the final part of the structure of charges project, following the implementation of a common methodology for lower voltage customers on 1 April 2010.

In this document, we outline the DNOs' proposals, set out our thoughts on key aspects of the methodology and highlight some areas of potential improvement. This is our initial assessment so we strongly welcome views from all interested parties on our thinking, the Impact Assessment and any other aspects of the DNOs' proposals. This feedback will be very important in informing our decision on whether to approve the methodology.

Context

Delivery of the electricity distribution structure of charges project is a priority for Ofgem, as we consider it will drive considerable improvements for consumers and other users of the distribution networks. Given the level of future investment required on the distribution network, and the challenges the network will face as we move to a low carbon economy we think it is important to ensure common, cost-reflective charging arrangements are put in place, which can be adapted over time to better reflect network developments. These charging arrangements should encourage efficient use of the current network, make best use of distributed generation connected to the network and provide benefit to consumers in the long term.

Historically, each distribution network operator (DNO) used individual methodologies to set customer charges. This changed for customers at the lower voltages on 1 April 2010, when a common methodology, the Common Distribution Charging Methodology (CDCM) was introduced. The Extra High Voltage Distribution Charging Methodology (EDCM), which the DNOs submitted to us on 1 April 2011, is designed to implement common arrangements for those at the higher voltages. Should we approve this methodology, it will start on 1 April 2012.

The development of the common methodologies has taken place over a long period. We have worked closely with the DNOs and other stakeholders throughout the development of the project. Both the DNOs and ourselves issued several consultations on the common methodology, including two by the DNOs on the proposed EDCM in 2010.

This consultation highlights areas that have changed since the DNOs' last consultation in December 2010. We also provide our thoughts on key aspects of their proposals and draw attention to a number of issues that may result in improvements to the methodology. We strongly encourage stakeholders to engage with this consultation, both on the points and issues we raise as well as the DNOs' proposals more broadly, to help inform our view ahead of our decision on the methodology.

Associated documents

- Delivering the electricity distribution structure of charges project, October 2008 (Reference number:135/08)

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/Decision%20document%201%20October%202008.pdf

- Next steps in delivering the electricity distribution structure of charges project: decision document, March 2009 (Reference number:24/09)

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/Next%20steps%20SoC%20decision%20doc.pdf

- Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements, July 2009 (Reference number:90/09)
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/July%20decision%20EHV%20charging%20and%20governance.pdf

- Electricity distribution structure of charges: the common distribution charging methodology at lower voltages, November 2009 (Reference number: 140/09)
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/CDCM%20decision%20doc%20201109%20(2).pdf

- Electricity distribution charging boundary between higher (EDCM) and lower (CDCM) voltages, July 2010 (Reference number: 90/10)
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/EHV%20boundary%20decision%201007.pdf

- Decision on revised submission and implementation dates for the EHV Distribution Charging Methodology (EDCM), September 2010 (Reference number: 120/10)
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/EDCM%20timelines%20decision.pdf

- Consultation letter on a licence change to the boundary between the CDCM and the EDCM related to LDNOs, March 2011 (Reference number:31/11)
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/Open%20letter%20consultation%20on%20Designated%20EHV%20Properties.pdf

- EHV Distribution Charging Methodology (EDCM) report and appendices, April 2011
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=679&refer=Networks/ElecDist/Policy/DistChrgs

- Charges for pre-2005 distributed generators' use of DNOs' distribution systems – proposed guidance, May 2011 (Reference number: 58/11)
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/Consultation%20on%20proposed%20guidance%200511.pdf

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Executive Summary

Purpose of the methodology and benefits

Our work on distribution charging began in 2000. In 2010, we approved a new methodology for low and high voltage customers. The introduction of an Extra High Voltage Distribution Charging Methodology (EDCM) for extra high voltage customers – generally large industrial customers and large scale distributed generation – is the remaining element of this work. It is an important contribution to our aim of protecting the interests of current and future network users.

We estimate that network companies will need to invest in excess of £30bn over the next ten years to provide the capacity required as we transition to a low carbon economy. Part of this investment will be on the transmission network. We are separately reviewing the transmission charging arrangements as part of Project TransmiT. TransmiT does not necessarily have implications for distribution charging due to the different nature of the networks.

We want to ensure that distribution network users are encouraged to make the most efficient use of the existing infrastructure and to contain the amount of new investment that customers have to pay for. We also aim to ensure that the cost of maintaining the networks and of funding new investment is allocated fairly across different customers. Importantly, we are keen to ensure that rewards are available for network users who manage their demand patterns to avoid using the network at peak times or who provide other benefits, such as generators who offset local peak demand.

We are one step closer to securing these benefits with the submission of the distribution network operators' (DNOs) proposed methodology to us on 1 April 2011.

Our assessment and potential conditions

Our initial assessment is that the proposals submitted by the DNOs are a substantial improvement on the DNOs' current methodologies and that the methodology largely meets the objectives set out for the project. The methodology is common, which makes it easier for suppliers and licensed distribution network operators (LDNOs) to operate across DNO areas. It gives price signals about where it is cheapest to connect on the network while ensuring charges are cost-reflective. Importantly, the methodology gives customers options for how they can manage their charge and provides credits to some generators where their output supports the network.

We think there might be some areas where the methodology could be improved. We set out some potential conditions we are considering placing on the DNOs – we particularly welcome feedback on these. These include whether to allow intermittent generators, such as wind farms, to receive credits and whether the DNOs should undertake further work to ensure the cost of spare capacity in assets is appropriately allocated to customers. We also think some technical changes might be required, such as around how discounts for LDNOs are calculated and how the total revenue to be recovered from generators is determined.

Impact of charges and potential mitigation

If we approve the methodology, there will be in some cases a significant rebalancing of charges across EHV customers. On average, charges for these customers across GB will reduce slightly, and we estimate that around 80 per cent of EHV customers will see either no change or a reduction in the distribution charge component of their electricity bill. However, some customers will see substantial increases in their charge in percentage and/or pound terms. These increases in charges have been of ongoing concern to us. We delayed the project previously to ensure DNOs could justify these movements and to allow further time for discussions with the most affected customers.

It is important to recognise that these changes are based on customers’ current behaviour and there may be opportunities to mitigate these increases. We also recognise that beyond the one off change in charge, the ongoing stability and predictability of charges is important to customers, as it helps to reduce risk.

In light of these issues, we are considering whether to require the DNOs to develop a package of measures to help customers deal with these changes. These measures could advise customers on what they can do to manage the change in their charge and provide analysis of how their charge might change over a multi-year period. It could also look at whether volatility of charges could be reduced, such as through changes to the model and by offering long term products to provide customers with some certainty of their charges over time.

In addressing the issue of large changes in charges, we are also considering whether we go further and phase or delay the implementation of the new charges. Each option has its advantages and disadvantages. While phasing or delay would provide time for the most significantly affected customers to adjust, it would disadvantage customers who stand to gain from the new methodology. It would also hold back realisation of the wider benefits of the new methodology we discussed above. Our initial view is that there could be a strong case for introducing the methodology in April 2012, according to the current schedule. We particularly encourage stakeholders to respond on this issue.

Next steps

Continuing our engagement with stakeholders on this project, we are holding a workshop for demand customers on 6 June 2011 to discuss the issues we raise in this document. We plan to undertake both individual and group consultations that will deal specifically with the needs of generators, LDNOs and other stakeholders.

We invite all stakeholders to respond to this consultation by **4 July 2011**. Following this consultation, we will consider all responses in making our decision on approval of the methodology and whether to apply conditions. If we approve, without delay or phasing, new charges would apply from 1 April 2012.

1. Introduction

Chapter Summary

In this chapter, we set out the purpose of this consultation and the background to the DNOs' and our work on a common methodology. We also outline the structure of the remainder of this consultation.

Purpose of this consultation

1.1. On 1 April 2011, the DNOs submitted their common EHV distribution charging methodology (EDCM) to the Authority for approval. This methodology covers use of system charges for all extra high voltage (EHV) users and high voltage (HV) users metered at a primary substation ("the higher voltages").

1.2. This consultation outlines the proposed EDCM submitted by the DNOs. It covers our thinking on some of its core principles and highlights issues where the DNOs have moved since their last consultation or issues where we consider that conditions may be necessary for us to approve the methodology. We welcome responses from interested parties on any areas discussed either in this consultation or within the DNOs' submission. To help parties to engage with this highly complex methodology, Chapter 2 provides a high level overview of the methodology and our thoughts for non-specialist readers.

Project background

1.3. We and the DNOs have consulted since 2000 on achieving more forward looking, locational-based charging models. There had been limited progress on the development of the methodologies, so in 2008, we placed a licence condition on the DNOs. We required that it be common across the DNOs and subject to ongoing open governance. We also set a specification to help DNOs develop the methodology and put in place a series of deadlines for development and implementation.

1.4. As a result, the Common Distribution Charing Methodology (CDCM), for lower voltage customers, was implemented on 1 April 2010. The DNOs continued to develop the methodology for higher voltage customers, including issuing a number of consultations in 2010. They submitted the methodology to us on 1 April 2011. This consultation is therefore one of the final steps in implementing common methodologies for users at all voltage levels.

1.5. We have required the DNOs to do this work because of the benefits that the methodology can achieve. The methodology aims to:

- drive efficient investment and use of existing network assets by setting prices that encourage customers to locate where there is spare capacity, which in the long term will reduce charges for all consumers
- support sustainable development through the connection of more distributed generation in areas of high demand and through encouraging demand side management
- encourage competition from licensed distribution network operators (LDNOs) and competition between suppliers (as we expect the introduction of a common method GB-wide to reduce barriers to entry)

1.6. We are separately reviewing the charging arrangements for the electricity and gas transmission networks as part of Project TransmiT[1]. The project is currently collecting evidence and assessing whether all or part of the transmission charging regime should be modified. It is also considering what changes could be made to facilitate the connection of new (including low carbon) generation. Due to the different nature of the networks, TransmiT will not necessarily have implications for distribution charging. If there are implications we think they should be incorporated into the distribution charging regime, we may seek to incorporate them, such as through the open governance processes the distribution charging methodologies will be subject to, or by conducting a significant code review of the existing distribution charging code.

Customers covered by the EDCM

1.7. The EDCM calculates use of system charges for customers connected to the DNO's distribution system at or above 22 kilovolts (kV) and customers whose meter is located at a primary substation, where a primary substation transfer voltage from 22kV or above to a voltage level below 22kV[2]. All other customers (ie LV and the remainder of the HV customers) received charges calculated by the CDCM.

1.8. There was some uncertainty about where this boundary might lie in the case of Licensed Distribution Network Operators (LDNOs) where there is no metering point. We issued a consultation on this issue in March 2011[3] and will shortly publish our decision.

[1] More information on Project TransmiT can be found at: http://www.ofgem.gov.uk/Networks/Trans/PT/Pages/ProjectTransmiT.aspx
[2] These customers are defined as 'Designated EHV Properties' under SLC 50A.11 of the electricity distribution licence.
[3] 'Consultation letter on a licence change to the boundary between the Common Distribution Charging Methodology and the EHV Distribution Charging Methodology related to Licensed Distribution Network Operators' 15 March 2011, available at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=666&refer=Networks/ElecDist/Policy/DistChrgs

Stakeholder engagement

1.9. The DNOs have published a number of consultations on their proposed methodology: an initial consultation on their proposed EDCM on 18 June 2010; an EDCM information pack containing results of the development work undertaken as of September 2010; a further consultation on the methodology on 21 December 2010; and a mini-consultation on LDNO charging on 11 February 2011.[4]

1.10. Throughout this process, the DNOs have engaged stakeholders both individually and collectively. They established the common methodology group (CMG) to take forward Ofgem's proposals, and encouraged stakeholders to attend. We have attended these meetings regularly to help progress this project. The DNOs have also held national and regional workshops to discuss their proposals with interested parties.

Open governance arrangements

1.11. Once implemented the EDCM will be subject to a governance regime, and change control arrangements, under the distribution connection and use of system agreement (DCUSA). The open governance arrangements allow for the development of the methodology over time.

1.12. Any DCUSA party can submit proposals to modify the methodology. These parties include DNOs, LDNOs, suppliers and generators, as well as by other parties materially affected by the methodology (with permission from the Authority). We note that the DNOs are required under the licence to review their methodology at least once per year.

Pre-2005 generators

1.13. We are currently working with DNOs and distributed generators (DG) to facilitate the introduction of UoS charges for DG that connected on terms agreed pre-2005. This is because as part of our DPCR5 Final Proposals we decided not to renew an exemption pre-2005 DG had from being charged for UoS. We considered that pre-2005 DG should be charged for UoS on the same basis as post-2005 DG in order that all DG are not unduly discriminated against and that all DG are encouraged to efficiently connect to and use DNOs' networks.

1.14. In order to introduce UoS charges for pre-2005 DG, it may be necessary for DNOs to pay compensation or refunds to pre-2005 DG. As part of this work, we published a decision on 23 August 2010 that sets out that any compensation paid by DNOs to pre-2005 DG should be unbundled from the calculation of UoS charges. This

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[4] These can be found on the ENA's website at http://2010.energynetworks.org/edcm-file-storage/6-consultations/

was to avoid over-complicating DNOs' UoS charging methodologies and polluting the charging signals produced by UoS charging methodologies.

1.15. On 9 May 2011, we published a consultation document that seeks views on proposed guidance for paying refunds to pre-2005 DG.[5] Our consultation on pre-2005 DG charging closes on 17 June 2011.

Structure of this document

1.16. We strongly encourage all stakeholders to read Chapter 2 as it provides an accessible overview of the methodology and our thoughts on it. The remaining chapters are more detailed and deal with issues specific to different customer groups.

1.17. We encourage demand customers to read Chapter 3 on the specific demand issues as well as Chapter 6, which covers issues common to demand and generation. Generators should Chapter 4 on generation charging as well as Chapter 6. LDNOs may wish to read both the demand and generation chapters in addition to Chapter 5 on charging proposals for LDNOs.

1.18. The document is structured as follows:

- Chapter 2 provides an overview of the EDCM, its objectives and our initial assessment of the DNOs' submission against these objectives.
- Chapter 3 outlines the proposed approach for demand customers and highlights areas for potential improvement.
- Chapter 4 discusses the proposed approach for generation customers and areas for potential improvement.
- Chapter 5 discusses the proposed approach for imbedded networks and areas for potential improvement.
- Chapter 6 discusses the issues common to all EHV customers.
- Appendix 2 provides a short history of the project.
- The Supporting Documentation provides an Impact Assessment illustrating the effect the implementation of the EDCM will have on customer charges.

[5] Available at:
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=684&refer=Networks/ElecDist/Policy/DistChrgs

2. Overview

Chapter Summary

This chapter is designed for the non-specialist reader. It provides an overview of the objectives of the EDCM and our approval process. We describe how the methodology operates and then give our thoughts on it. We discuss possible conditions we consider may improve the EDCM and flag potential areas of further development. Finally, we discuss the impact of the EDCM on customers and what might be done to manage this.

Question 2.1: What are your views on the key issues with the methodology we have highlighted? Are there any other issues or concerns with the methodology as a whole that we should consider?
Question 2.2: Should we approve the methodology, do you agree with our proposal to implement it in full from 1 April 2012? If not, why is phasing-in charges or delaying implementation appropriate?
[Note: we would appreciate early responses to this question by 24 June 2011 if possible – although we will still consider responses submitted after]

Principles and objectives of the EDCM

2.1. The principles and objectives underpinning the project are that the methodology should:[6]

- reflect the costs (or benefits) imposed by users on the network, including the future costs (or benefits) that arise from current behaviour, so as to encourage efficient use of the network and therefore lower overall costs
- be transparent in terms of how charges are calculated, to enable customers to understand their charge
- facilitate competition, for example between suppliers and licensed distribution network operators (LDNOs)
- respond to and facilitate developments in the network, such as the increasing connection of distributed generation, which helps to support the objective of sustainable development

2.2. A key requirement for the methodology is that it is common across DNOs, which assists those that participate in the market across GB. The methodology is also subject to open governance arrangements. This will enable industry participants to

[6] We set out principles and objectives for the structure of charges project more generally in "Delivering the electricity distribution structure of charges project" Ref 135/08 1 October 2008 available at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=447&refer=Networks/ElecDist/Policy/DistChrgs

propose improvements thus allowing for the development of the methodology over time.

How we assess and approve the EDCM

Our assessment

2.3. We are required to assess the methodology, having regard to our principle objective and duties, against the following 'Relevant Objectives'[7]. These objectives are to be considered 'in the round'[8].

- compliance with the EDCM facilitates the discharge by the licensee of the obligations imposed on it under the Electricity Act and by the licence
- compliance with the EDCM 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
- compliance with the EDCM results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the licensee in its Distribution Business
- so far as is consistent with the first three Relevant Objectives, the EDCM, so far as is reasonably practicable, properly takes account of developments in the licensee's Distribution Business

2.4. In developing the EDCM, the DNOs were also required to have regard to the principles and assumptions set out in our decision of 31 July 2009[9] where we described the principles of how the methodologies should work. The DNOs set out their own assessment of the EDCM against both the Relevant Objectives in paragraphs 220-227 of their submission, as well as where they deviated from our July 2009 principles (Appendix 9).

Our approval

2.5. We may approve the methodology in full or subject to conditions[10]. These would specify the further actions the DNOs need to take in order for the EDCM to better achieve the Relevant Objectives. They would also outline the time frame in which these actions must be completed.

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[7] As defined under SLC 50A.7-10.
[8] SLC 50A.36.
[9] 'Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements'. Available at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=487&refer=Networks/ElecDist/Policy/DistChrgs
[10] SLC50A.20-22.

Overview of the proposed EDCM

2.6. The EDCM calculates distribution use of system (DUoS) charges for higher voltage customers. These are typically large industrial and commercial customers and large distributed generators. DUoS charges are paid by customers for the use of the electricity distribution network. It is through DUoS charges that DNOs recover their regulatory revenue allowances ('allowed revenue') set by the price control review.

2.7. The submission includes specific charging arrangements for different groups of customers, including demand customers (customers that import electricity from the network), generation customers (customers that export electricity to the network), mixed import/export sites, LDNOs and offshore networks. It also includes arrangements for customers to enter into demand or generation side management agreements.

2.8. The EDCM aims to generate cost-reflective and site-specific charges. For each customer the charge aims to reflect the cost of using the network at their location. For demand customers, charges are primarily driven by their maximum import capacity (the maximum amount of electricity they have agreed with the DNO that they may import from the network at any time), how much of this capacity they use or 'consume' at peak times and the value of the network assets they use. For generation customers, the key factors are their capacity and the value of the assets they use exclusively and for those eligible for credits, the amount they export during peak times. For both, the amount of capacity used to calculate parts of the charge might be reduced if they have a demand or generation side management agreement in place with the DNO.

How the EDCM calculates DUoS charges and credits

2.9. The following sections provide a high level overview of how charges are derived for demand and generation customers. Chapters 3 and 4 provide a more detailed overview of how the charges are derived for demand and generation customers respectively. Chapter 5 details how discounts on charges for LDNOs are calculated, although we do not discuss these here.

For demand customers

2.10. The way the EDCM calculates charges for generation customers can be broken down into three parts: calculating the incremental cost of reinforcement; allocating specific costs to customers; and then 'scaling' the charge to match the DNO's allowed revenue.

Part 1 – The incremental reinforcement charge

2.11. The incremental charge is designed to reflect the fact that where the network is close to fully loaded, increasing capacity or peak time consumption at this location may trigger or bring forward reinforcement. This is less likely to occur in less congested parts of the network and thus the resulting charge would be lower.

2.12. It is derived using either the Long Run Incremental Cost (LRIC) or the Forward Cost Pricing (FCP) methods.[11] Both methods calculate the charges related to the future cost of network reinforcements based on the customer's location. LRIC estimates the cost of bringing forward reinforcements for each additional unit of capacity at the customer's location. FCP forecasts the actual costs of reinforcement and then spreads them across the capacity of users of that part of the network.

2.13. The resulting charge thus provides a price signal about both the cost at that location per unit of capacity and the cost of using that capacity during peak periods. This signals where it is most efficient to connect to, and operate, on the network.

Part 2 – Allocation of costs

2.14. The second part of the process is to allocate to individual customers identifiable costs (such as network rates and the 'direct' cost of maintaining assets). This uses specific cost drivers (eg the amount of assets used by the customer, at both where they are connected, as well as right up the network to where it connected to the national grid) to calculate the portion of costs that should be paid by that customer. This helps to ensure that the charge reflects the costs imposed by individual customers on the network, ie it is cost-reflective.

Part 3 – Scaling to match allowed revenue

2.15. The final step of the process is to allocate any 'residual' revenue to customers. This residual occurs when the first two steps do not produce charges high enough to recover the DNO's allowed revenue, or conversely, the charges produced by the model are in excess of this amount. In each case, each customer's charge is 'scaled' up or down respectively to enable the DNO to recover its allowed revenue[12].

2.16. The proportion of customers' charges that each of these components makes up will be different for every customer. Figure 2.1 below shows the average make up per DNO area.

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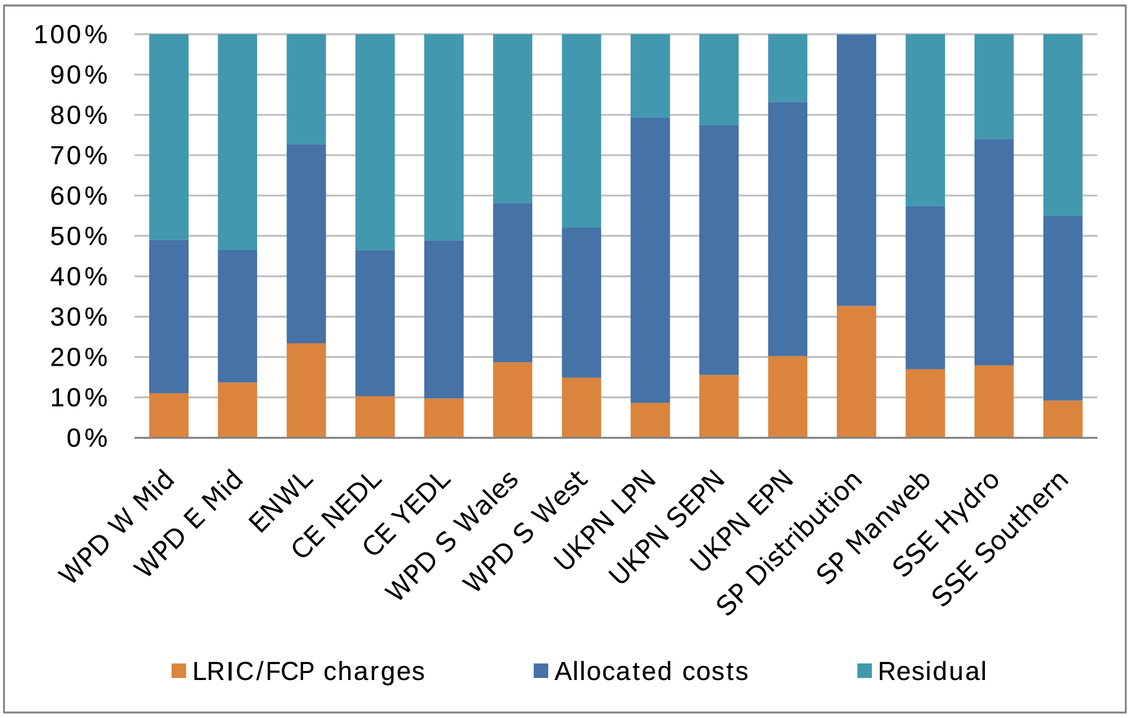
[11] DNOs have a choice of which method to use. The LRIC model is used by ENWL, CE NEDL, CE YEDL, WPD S Wales, WPD S West, UKPN LPN, UKPN SPEN and UKPN EPN. The FCP method is used by WPD W Mid, WPD E Mid, SP Distribution, SP Manweb, SEE Hydro and SSE Southern.
[12] The allowed revenue is actually split into three for the purposes of scaling: the EDCM demand revenue target, the EDCM generation target and the CDCM target. EDCM demand customers charges are scaled to the EDCM demand revenue target. The calculation of this target is discussed in Issue 1.

Figure 2.1 Breakdown of components of demand customers' charge



For generation customers

2.17. The EDCM calculates both charges and credits for generators that export power to the network. The calculation of these is similar but much simpler than for demand customers.

2.18. For charges, the EDCM also calculates an incremental charge (Part 1 above) where a generator triggers or brings forward reinforcement[13]. Some costs are also allocated (Part 2) to specific customers but in this case only based on the assets used exclusively by the generator, rather than those they share with others. Finally, scaling (Part 3) is also applied where the revenue does not match the total to be recovered from generators.

2.19. Credits are simply the reverse of the charge that is applied (in Part 1) to demand customers. This is because the generator's output offsets demand in this part of the network therefore deferring reinforcement. No costs are allocated to this

[13] In many cases, generators' output offsets the electricity that demand customers import from the network. However, where the generator actually triggers or brings forward reinforcement, the methodology will produce a charge. This can occur where there is little demand in that part of the network so the generator's output must travel further up or across the network

credit and it is not scaled to match a revenue target. (We note that credits are not available to all generators and further discuss this in Issue 11.)

Our thoughts on the EDCM methodology

Our assessment

2.20. Our initial assessment is that it is a substantial improvement on the DNOs' current methodologies and that it largely meets the objectives set out for the project, for the following reasons:

- **The methodology is common** – market participants will only need to understand a single charging methodology going forward. This should encourage competition by reducing barriers to entry for suppliers and LDNOs.
- **Locational pricing** – connection is encouraged by lower prices in less congested parts of the network, while prices are higher in more congested parts of the network reflecting the costs of reinforcement in these areas. This should encourage new connections in areas with spare capacity and for current users in congested parts to manage their usage.
- **Generation credits** – non-intermittent generators receive credits if they are located in demand-dominated areas and operate during times of system peak. This reflects the benefits they bring to the network in terms of avoiding reinforcement.
- **Demand and generation side management** – the proposals encourage users to contract with the DNOs in order to reduce costs at system peak.
- **Cost reflectivity** – charges are dependent on users' agreed capacity, consumption at system peak and the network assets utilised. This aims to ensure that charges fairly reflect the costs imposed by users on the network.
- **The methodology will be subject to open governance** – industry participants will be able to suggest changes to the methodology that should help ensure it is kept up to date with developments in the distribution network and continually improved.

2.21. We think there might be some areas where the methodology could be improved. We set out some potential conditions we are considering placing on the DNOs in the next section.

The development process

2.22. The DNOs have worked hard over the development of the EDCM to continually improve the methodology and ensure that issues are resolved. This included working with us and other stakeholders to identify these issues and propose solutions. These improvements are designed to ensure that the principles and objectives for the project are fulfilled and that anomalies and outliers in the calculation of charges are addressed.

2.23. For example, since their December 2010 consultation, they have made a number of improvements to the methodology, which we draw specific attention to in this consultation. These include:

- The choice of the method to scale charges so that they match the DNO's allowed revenue. The DNOs chose the site-specific method that estimates the specific amount of asset used by each customer, in a bid to be as cost-reflective as possible.
- The application of caps and collars to the network use factors that are an integral part of calculating the amount of assets use for scaling purposes. This helped to minimise the chance of outliers, ie excessive or very low charges that they may be considered unreasonable.
- Other smaller changes, such as preventing double charging for reactive power, changes to how credits are calculated for generators and further development of the demand and generation side management arrangements.

Potential conditions

2.24. While our initial assessment of the DNOs' proposed EDCM is broadly positive, we think that there are some areas where changes to the methodology might help the EDCM to better achieve the Relevant Objectives. Accordingly, we discuss the possibility of placing certain conditions on the DNOs as part of our decision to approve the EDCM. We encourage stakeholders to provide their views on these potential conditions and any others they think would enable the methodology to better achieve the Relevant Objectives.

Demand – allocation of spare capacity

2.25. A key part of the EDCM is ensuring that customers' charges reflect the costs they impose on the network. This has resulted in changes to the EDCM such as the allocation of costs to customers based on the specific assets that they use. We think there might be an argument that where there is spare capacity on assets that is not used by anyone, it might instead be appropriate to recover the associated costs across all users, through the scaling process. This is because while spare capacity represents a cost, it can also provide a wider benefit in terms of overall resilience, such as during network outages.

2.26. Whether a change should be made to the methodology depends on how material the issue is. In our discussions with the DNOs, they do not seem to believe that this is a material issue in light of the cap and collar. This effectively places a limit on the amount of assets the customer is deemed to use thus reducing the chance they will have to meet the costs of a large amount of spare capacity. We therefore need more evidence from the DNOs on the materiality of this issue and whether a change needs to be made (see Issue 5).

Generation – credits for intermittent generation

2.27. The DNOs do not propose to provide credits to intermittent generation (eg wind and solar). We think that intermittent generation may provide some benefits to the system in terms of reducing reinforcement costs. These include reducing system peak loading and providing support in outage conditions.

2.28. We are therefore considering placing a condition on the DNOs to allow intermittent generation to receive credits. We propose that these credits be calculated in a different way to non-intermittent generation, reflecting the fact that their output cannot be relied upon as much by network planners. Further detail on our proposals for how credits might be calculated can be found in Issue 11.

Generation – the revenue target

2.29. The methodology calculates an amount of revenue that is to be recovered through charges to generators. This helps to ensure that, as a group, generators pay an amount that reflects the costs they impose on the network.

2.30. We think that there may be an inconsistency in the calculation of this target. We propose to place a condition on the DNOs to fix it unless there is a good reason for the inconsistency. This would result in a minor reduction in the amount recovered from generators.

Licensed Distribution Network Operators (LDNOs) – discounts on scaling component of the charge

2.31. The methodology provides LDNOs with a discount of 50 per cent on the DNO's indirect costs, which are calculated based on the capacity of the customer. This recognises that LDNOs have their own indirect costs they need to recover from customers. If there were no discount, the LDNO would have to absorb these costs through other parts of the charge.

2.32. We think that similar logic might be applied to capacity-based charges other than the indirect costs charge, notably scaling of both demand and generation charges, for which no discount is given. This scaling arguable includes 'downstream' costs that will be incurred by the LDNO and which the DNO will not incur. This is further discussed in Issue 3.

Common issue - LRIC Branch Capping

2.33. The DNOs have employed a method of 'sense checking' the incremental charge component of the final charge that is produced by the LRIC model. This is designed to avoid the model producing charges that may be considered unreasonable, by limiting charges to the annuitised reinforcement cost of the branch. We are comfortable with the intent of this approach.

2.34. We are considering, however, placing a condition on the way the cap is applied. Currently, charges and credits, and demand and generation, are considered together. We think it might be better to split each of these out and apply the cap individually. We explain our rationale in Issue 20. The effect on the LRIC component of the charge is likely to be minor and potentially offsetting: splitting charges and credits may increase slightly the number capped while splitting generation and demand may decrease it slightly.

Other potential improvements

2.35. There are a number of areas that we think may not be significant enough to potentially warrant a condition, but which might be addressed through other means. We seek all stakeholders' views on these matters and encourage the DNOs to respond on these issues in their responses to this consultation, as some of them are quite technical.

2.36. Subject to stakeholders' views, some of these could be incorporated prior to implementation. Should we agree, we might make these a condition of approval to ensure the change is transparent. Other more long term changes may be better dealt with through the open governance process that allows changes to be considered through the Distribution Charging Methodology Forum's Methodology Issues Group that is open to industry stakeholders. The issues are as follows:

Demand – calculation of capacity for allocation of costs and the residual (Issue 3) – this calculation uses two different units of capacity (kVA and kW). We seek views on whether using different units is appropriate, as it affects how much reactive power is taken into account.

Demand – customer categories (Issue 7) – the methodology includes 15 different categories of customers but these may not be necessary for the operation of the charging model. Removing these categories may reduce complexity and increase transparency, so we seek stakeholders' views on whether they are actually required.

Demand - sole use asset charge (Issue 17) – for the majority of revenue recovered by scaling, only the customer's shared assets are taken into account in determining their share of revenue. We invite stakeholders to respond on whether they are comfortable with this, or think sole use assets should also be a factor.

Generation - charges for mixed sites (Issue 12) – the methodology applies a fixed assumption about the amount of assets used by the demand side of site that also has generation. We seek stakeholders' views on whether this assumption is appropriate, given the difficulty of estimating a reasonable value.

Common - demand and generation side management agreements (Issue 18) – these agreements offer the possibility for customers to reduce their charge, so we are keen to understand from the DNOs whether any customer can enter such agreements or whether they are at the discretion of the DNO.

LDNOs – capping of discounts on charges (Issue 16) – currently discounts for LDNOs may be no higher than 100 per cent of the charge. While there are no instances of discounts greater than this, we encourage stakeholders to respond on whether this cap is appropriate, particularly if stakeholders feel it may be an issue in the future.

Derogations

2.37. The DNOs have not formally submitted any requests for derogations as part of their methodology. As noted, based on our current understanding of it, we think the methodology is suitable for the vast majority of customers. If there were circumstances where the assumptions in the methodology were inappropriate for some customers then we would expect the DNOs to identify these and request a derogation to avoid inappropriate charges. We expect that these would represent exceptional circumstances. As part of the derogation request, the DNO would need to propose a modification to correct the issue.

2.38. We note that the DNOs outline in their risk assessment of the project that some derogations may be required as a risk mitigation measure against some circumstances.[14] These include if generators in certain situations consider their charges to be unfair, the nature of the outcome of the arrangements for charging generators connected prior to 2005 and to accommodate non-standard commercial arrangements. We note that they are not collectively asking for a derogation at this point. We will consider any derogation request if and when it is brought forward.

2.39. We also note that in the risk assessment, Scottish and Southern Energy Power Distribution has stated that there is a high likelihood that they will be unable to fully implement portfolio tariffs. This is due to the need to potentially utilise significantly more line loss factor classes (LLFCs) than are available for use in the settlement system.

2.40. Any request for a derogation must be brought forward with sufficient time to enable a proper consultation period and for illustrative charges to be published prior to the commencement of the EDCM on 1 April 2012 (subject to our approval).

Impact of methodology and management of charges

2.41. For around 80 per cent of customers, the new methodology will see their charges stay the same or reduce. Other customers, however, will see potentially large increases in their charge, as a result of moving from the DNOs previous methodology to the EDCM. After implementation, there may be some volatility in charges due to the assumptions and calculations used in the methodology.

2.42. Both these ongoing changes and in particular the one off change is of significant concern to us, so we discuss in the document what could be done to manage them. We consider whether we should require the DNOs to develop a

[14] See Appendix 3 of their Methodology on ‘Areas of Risk’.

package of measures to help customers manage their charges. We also consider whether modifying the implementation timetable would be appropriate. These issues are further discussed below as well specifically under Issue 21 of Chapter 6.

Impact assessment

2.43. We set out our Impact Assessment as a supplementary document to this consultation. The following paragraphs provide a high level summary.

2.44. For demand customers, tariff changes vary widely across DNOs and between different customers. On average across DNOs, charges are decreasing. Customers at all network connections levels experience this except those connected to 132kV circuits. Similarly, demand customers in all DNO areas except CE's North East England region see an average reduction in their charge.

2.45. On an individual basis, there will be some significant changes in charges for some customers. The absolute highest charge increase for an individual customer is £1.37m (this represents an increase of 245 per cent) and the largest reduction is £1.12m (this represents a decrease of 66 per cent). Where the customer's existing charge is very small, then the percentage change may in some cases be significantly higher than this.

2.46. The majority of generators covered by the EDCM will be charged DUoS for the first time. Around 12 per cent will receive a net credit. The majority (72 per cent) will pay no higher than £50,000 per annum. We also recognise that the charges for generators are based on current behaviour and there may be the potential to reduce their charge by modifying their capacity or time and amount of export.

2.47. While domestic consumers' charges are not covered by the EDCM, they still see some impact from the EDCM. This includes a very small one off increase (£0.37) in DUoS charges due to the way the EDCM divides up the allowed revenue. Consumers are expected to benefit from any lower overall network investment the EDCM encourages through lower DUoS charges.

2.48. We expect the EDCM to improve competition, as having a common methodology should reduce barriers to entry for suppliers and LDNOs. For LDNOs, the EDCM aims to ensure that they receive a reasonable margin. The EDCM should also help to facilitate competition between generators by ensuring that they are charged on a uniform basis and thus receive equivalent price signals.

2.49. The EDCM facilitates sustainable development and the move to a low carbon economy. It does this by incentivising customers to modify their behaviour to use assets more efficiently, which in turn helps to reduce losses (which must be replaced by additional generation). The EDCM also helps by providing clear price signals for the connection of generators (some of which are renewable), although we note that as some will be charged for the first time, there may be a negative impact on some generators.

Helping customers to manage their charges

2.50. In view of the significant movements in charges described in the Impact Assessment, it is important to recognise that these charges are based on customer's current behaviour. There may be potential for customers to mitigate increases in charges, as the EDCM offers opportunities to customers to reduce their charges, which are further discussed in the demand and generation chapters.

2.51. A separate but related issue is the ongoing stability and predictability of charges. The methodology is very sophisticated and uses many input assumptions that may vary over time. This means that in addition to external factors, such as changes in the DNOs' allowed revenues, charges may change through no change in the customers' behaviour. We understand that these are significant concerns for customers as having transparent and predictable charges reduces their risk.

2.52. In light of the above two issues, we are considering whether to require the DNOs to develop a package of measures that help customers deal with these issues. This could advise customers on what they can do to manage their charge. It could provide analysis of possible changes in customers' charges over a multi-year period as well as investigate whether any changes could be made to the model to reduce volatility. As part of this, we could also require the DNOs to develop long term products that provide customer with certainty of their charges and include consideration of whether such products may be tailored to those seeing large changes in their charge as a result of the EDCM (or other similar options).

2.53. We note that DNOs are already undertaking work on some of these issues. We welcome feedback on what customers consider would be most useful to them in managing both the one-off and ongoing changes in charges.

Options around implementation

2.54. In helping customers manage the changes in charges discussed above, there may be options beyond the potential package of measures discussed above. That is, the implementation of the new charges could be delayed or phased. These may help to mitigate some of the impact of the change in charges, although each has downsides.

2.55. We consider there are four options around the timing of implementation, which we assess in the Table 2.1 on page 25. While our initial view is that implementation in full from 1 April 2012 is the best approach, we welcome stakeholder views on these options, particularly given the inherent tradeoffs involved in each option.

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Table 2.1 – Assessment of options for phasing or delaying implementation

Details	Pros	Cons
Implementation as planned All new charges calculated by the EDCM apply from 1 April 2012	- benefits of the new methodology experienced as soon as possible - customers have already been given substantial notice that charges will change	- significant impact on some customers seeing rises in their charges, which could affect the viability of some businesses
Phased implementation for all customers The introduction of new charges occurs progressively over a set period. For example, 33 per cent of the change could occur in the first year, 66 per cent in the second year and 100 per cent in the final year upon full implementation.	- change in charge is smoothed for all customers - customers given time to change their behaviour (if possible) to mitigate the impact of the new charge	- benefits of lower charges delayed for those customers seeing reductions - cost-reflectivity of charges would be diluted over the phasing period - would make modifications to the methodology over the phasing period difficult as they would have to take into account phasing arrangements - may be difficult to implement practically as it may require a change to the licence and it would be very complicated to adjust tariffs to achieve this
Phased implementation only for those most affected Phasing of charges would be restricted only to those experiencing an increase above a certain pound and/or percentage value. The difference could be: (a) met by the DNO and then recovered from the customer at a later date (b) recovered from other customers.	- impact of one-off change in charges is reduced for those that will be most affected - these customers are given time to change their behaviour (if possible) to mitigate the impact of the new charge - under (a), customers seeing decreases in their charge are not disadvantaged by the phasing	- cost-reflectivity of charges would be diluted over the phasing period - may be difficult to implement practically as it may require a change to the licence and be complex - it would be an arbitrary decision about which charges to phase - under (a), there is an impact on DNOs from deferring when they collect their revenue, although this would be limited to the extent phasing is restricted to a small group of customers - may not be fair for other customers, under (b) as their charges will increase to meet the difference
Delayed implementation Implementation of new charges is deferred, eg to April 2013, April 2014 or until the start of the next price control period in April 2015.	- 'cleanest' method of mitigating the impact of changes in charges and easiest to implement - customers given time to change their behaviour (if possible) to mitigate the impact of the new charge - provides more time for the DNOs to develop long term products and to help customers manage their charges	- benefits of the new methodology are deferred - benefits of lower charges delayed for those customers seeing reductions - customers with decreases in charges have to wait longer for this benefit

3. Charging proposals for demand customers

Chapter Summary

In this chapter, we summarise the EDCM proposals for charging of demand (load) customers, highlight key issues and principles, and set out our initial thinking.

Question 3.1: Do you agree with our assessment that the approach for the revenue target is reasonable?
Question 3.2: Do you think the principle the maximum import capacity is a cost driver at the voltage of connection is reasonable for charging purposes?
Question 3.3: Do you agree with our view that reactive power flows should be incorporated as part of the capacity that attracts indirect costs and 20 per cent of the residual?
Question 3.4: Is it appropriate to consider the specific assets the customer uses for the calculation of the customer's charge, or would it be more appropriate to consider only the voltage levels the customer uses for the calculation of its charges?
Question 3.5: Do you think that the 'spare capacity' issue we identify should be addressed?
Question 3.6: Do you think notional asset values should take into account assets below the customer's voltage of connection?
Question 3.7: Are there any other demand specific issues that you think we should consider as part of our decision?

Overview of the methodology for demand customers

3.1. Broadly, the EDCM calculates distribution use of system (DUoS) charges for demand customers (customers that import electricity from the distribution network) as follows:

- The EDCM identifies four cost drivers: maximum import capacity; consumption at peak; sole use asset value; and notional shared asset value.

- The EDCM allocates some costs to customers based on the cost drivers above. The costs allocated on this basis are direct operating costs, indirect costs and network rates that are in the EDCM revenue target, the DNO's total transmission exit charges and the LRIC/FCP charge components.

- Total recovery (excluding recovery from exit charges) across all EDCM demand customers is compared to a revenue target (see Issue 1 below) and the residual is allocated to customers partly on the basis of capacity (see Issue 3 below) and partly on the basis of notional shared asset value (see Issue 4 below).

3.2. Table 3.1 sets out the cost driver of each allocated cost/revenue component.

Table 3.1 Cost drivers of each cost and revenue component allocated to DUoS charges of EDCM demand customers

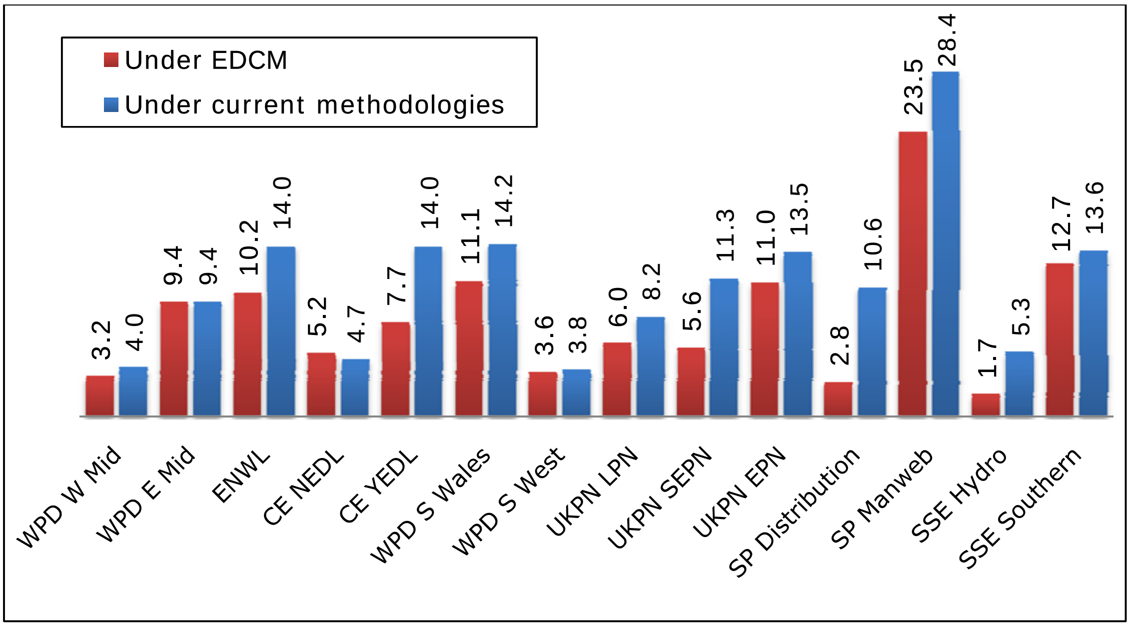
Source of charge	Cost driver			
	Maximum import capacity	Consumption at peak	Sole use assets value	Notional shared asset value
LRIC/FCP model	✓ (‘local component’)	✓ (‘remote component’)		
Direct costs			✓	✓
Network rates			✓	✓
Indirect costs	✓	✓		
Residual (80%)				✓
Residual (20%)	✓	✓		
Transmission exit charges		✓		

3.3. The ‘local’ and ‘remote’ components refer to two distinct charge components obtained as an output of the LRIC and FCP models. The local component is related to reinforcement costs at the voltage level of connection of the customer and the remote represents costs related to reinforcements at higher voltage levels. We note that in the case of FCP the ‘remote’ component is the ‘parent’ plus ‘grandparent’ ‘network group’ charges.

3.4. For the allocation of the remote LRIC/FCP charge component, ‘consumption at peak’ refers to forecast consumption during the super-red time band within the charging year. For the allocation of indirect costs and 20 per cent of the residual, ‘consumption at peak’ generally refers to consumption during the super-red time band in the most recent regulatory year for which data is available. The super-red time band is a period when the network is highly loaded and when the annual simultaneous maximum demand is likely to occur (see Table 4.4 in this consultation for a description of the DNOs’ super-red time bands).

3.5. Figure 3.1 shows a comparison of total revenue from EDCM demand customers under current charging arrangements and under the EDCM. Except in the case of CE NEDL, where the revenue under the EDCM is slightly higher than current, in all other DNO areas the revenue under the EDCM is falling. That means that, *as a group*, demand customers would pay less under the EDCM than they would under current charging arrangements.

Figure 3.1 Total revenue (£m) from EDCM demand customers under current charging arrangements and under the EDCM



Source: Ofgem analysis based on EDCM models in EDCM submission to Ofgem, April 2011

Overview of the tariff structure

3.6. Under the EDCM, demand customers will be subject to tariff components as set out in Table 3.2. We briefly discuss each tariff component below.

Table 3.2 Demand tariff components

Tariff component	Unit	Application	Comments
Fixed charge	p/day	Applied as a fixed charge	Sole use asset charges for direct operating costs and network rates
Import capacity charge	p/kVA/day	Applied to the maximum import capacity	Reflects the local element of the FCP/LRIC charge 1, pre allocation of direct operating costs, indirect costs, network rates, transmission exit charges and the demand scaling charge
Super-red unit rate	p/kWh	Applied to units consumed during the DNO's super-red time band	Reflects the remote element of the FCP/LRIC charge 1

Source: Based on tables 1 and 3 of the EDCM submission

3.7. The fixed charge is for costs associated with the customer's sole use assets. Two types of costs are allocated based on the customer's sole use asset value: direct operating costs and network rates. The methodology for sole use asset charges is common to demand and generation and is discussed in Issue 17.

3.8. The import capacity charge has six different elements:

- **The local LRIC/FCP component** reflects costs related to future demand-led reinforcements at the voltage of the customer's connection.
- **The direct operating costs and network rates components** reflect the DNO's cost in respect of these items. The amount of direct operating costs and network rates within the EDCM revenue target is allocated to customers based on their notional shared assets (see Issue 4).
- **The indirect costs component** reflects the DNO's costs in respect of this item. The amount of indirect costs within the EDCM revenue target is allocated to customers based on capacity. The relevant capacity is a combination of the maximum import capacity and capacity used at system peak (see Issue 3).
- **The exit charge component** is related to costs charged by the transmission company in respect of transmission connection points (Grid Supply Points (GSPs) in England and Wales and Bulk Supply Points (BSPs) in Scotland). Total DNO exit charges are allocated to customers based on their peak time consumption (see paragraphs 99 to 101 of the submission).
- **The scaling charge component** is a charge to cover the difference between the revenue target and total recovery from cost-based charge components (including the LRIC/FCP charges). The scaling component can be positive or negative. The calculation of the revenue target and its rationale are discussed under Issue 1 below. The allocation of the residual is discussed in Issue 6 below.

3.9. The super-red unit rate is equal to the remote LRIC or FCP element, uplifted for reactive power flows (see Issue 19). The rate reflects costs related to future reinforcement of network assets above the customer's level of connection. The rate applies to kWh units that the customer is forecasted to consume during the super-red period within the charging year.

3.10. The annual demand UoS charge is given by the following formula:

DUoS charge (£) = [Fixed charge (£)]

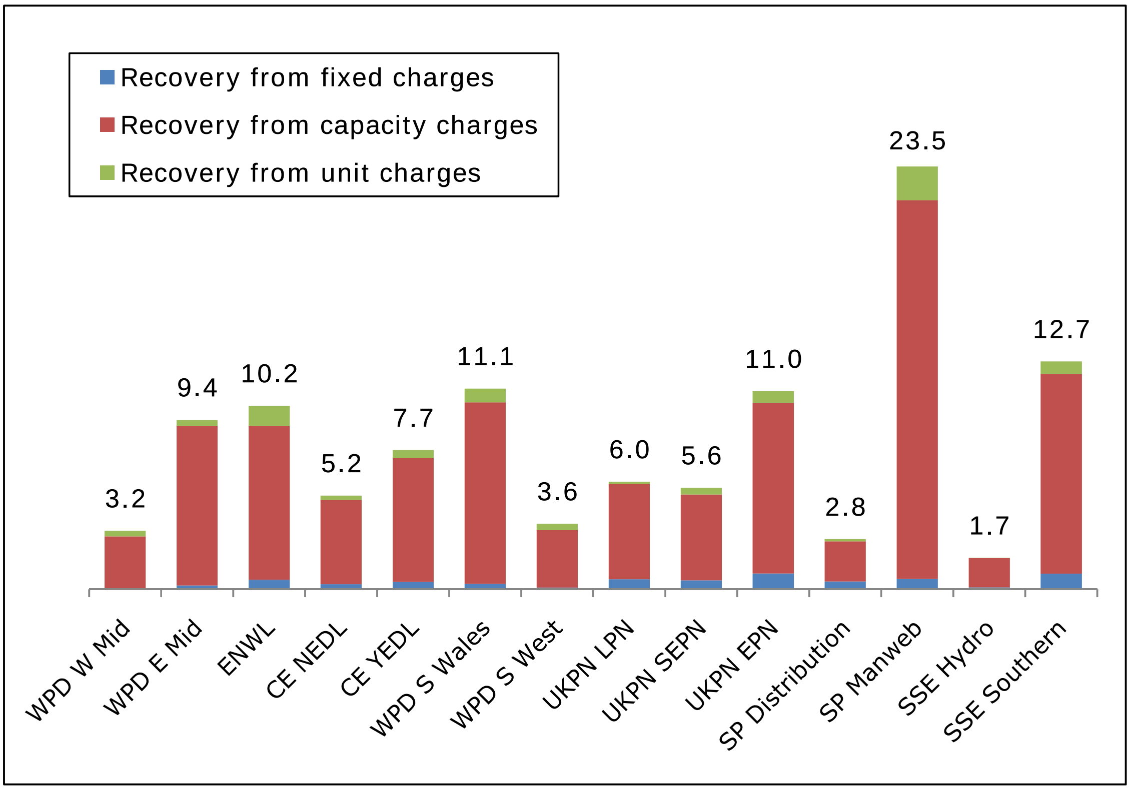
+ [Capacity charge (£/kVA)] * [Maximum import capacity (kVA)]

+ [Super-red unit rate (£/kWh)]*[Units imported during super-red hours (kWh)]

3.11. In addition to the above, customers that exceed their maximum import capacity would be charged for the excess at the same rate as the import capacity charge for capacity within the allowed limit. The charge will apply for the duration of the month in which the breach occurs. More details are provided in paragraphs 177 to 183 of the EDCM submission.

3.12. Figure 3.2 shows total revenue recovered from demand customers by tariff component for each DNO area. Around 90 per cent of revenue from demand customers is recovered through capacity charges.

Figure 3.2 Recovery from EDCM demand by tariff component (£m)



Source: Ofgem analysis based on EDCM models in EDCM submission to Ofgem, April 2011

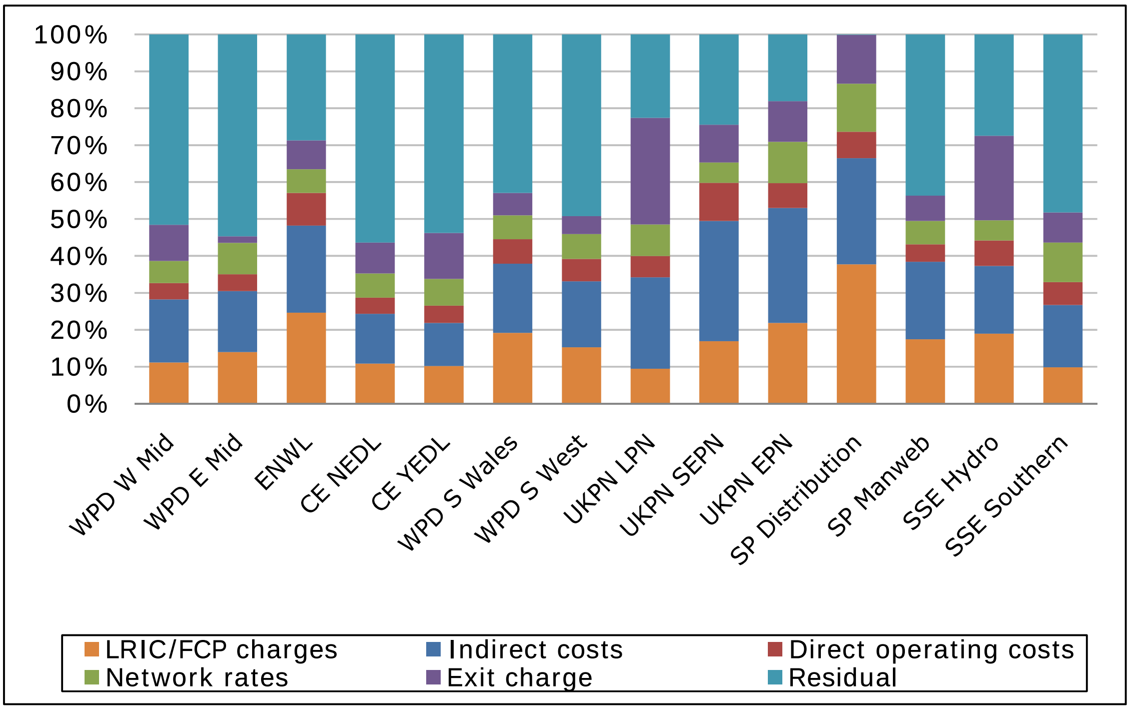
3.13. Table 3.3 shows the percentage recovery from each charge component out of the DNO’s total revenue recovery from EDCM demand customers. The table demonstrates that the residual has the largest contribution to final charges – around 50 per cent in a number of DNO areas. Recovery through LRIC/FCP charges ranges from 9.5 per cent (UKPN LPN) to 37.7 per cent (SP Distribution). These percentages can broadly be interpreted as the average proportion of the component in final DUoS charges. Figure 3.3 display the same percentages on a graph.

Table 3.3 Percentage of total recovery from demand customers by charge component

DNO	LRIC/FCP charges	Indirect costs	Direct operating costs	Network rates	Exit charge	Residual
WPD W Mid	11.1%	17.1%	4.4%	6.0%	9.8%	51.6%
WPD E Mid	14.0%	16.5%	4.5%	8.5%	1.8%	54.7%
ENWL	24.6%	23.6%	8.8%	6.4%	7.8%	28.7%
CE NEDL	10.8%	13.5%	4.4%	6.5%	8.3%	56.4%
CE YEDL	10.2%	11.6%	4.7%	7.2%	12.5%	53.8%
WPD S Wales	19.2%	18.7%	6.6%	6.4%	6.1%	42.9%
WPD S West	15.3%	17.9%	6.0%	6.7%	4.9%	49.2%
UKPN LPN	9.5%	24.8%	5.8%	8.5%	28.9%	22.6%
UKPN SEPN	16.9%	32.5%	10.3%	5.5%	10.2%	24.5%
UKPN EPN	21.8%	31.2%	6.7%	11.2%	11.0%	18.1%
SP Distribution	37.7%	28.7%	7.2%	13.0%	13.2%	0.2%
SP Manweb	17.4%	21.0%	4.8%	6.3%	6.9%	43.7%
SSE Hydro	18.9%	18.4%	6.9%	5.4%	22.9%	27.5%
SSE Southern	9.8%	16.9%	6.2%	10.7%	8.2%	48.2%
Average	**17.0%**	**20.9%**	**6.2%**	**7.7%**	**10.9%**	**37.3%**

Source: Ofgem analysis based on EDCM models in EDCM submission to Ofgem, April 2011

Figure 3.3 Percentage of total recovery from demand customers by charge component



Source: Ofgem analysis based on EDCM models in EDCM submission to Ofgem, April 2011

3.14. The following sections outline how both the revenue target and individual charges are constructed. We draw out some of the key topics in the proposed method of charging demand customers. We also provide our thoughts on these topics.

Issue 1: the demand revenue target

The proposals

3.15. The EDCM demand revenue target is a sum of money that each DNO sets out to recover from its EDCM demand customers as a whole through use of system charges.[15]

3.16. The DNOs' proposal for the calculation of the revenue target is to allocate DNO level costs to individual EDCM customers based on their proportion of asset value out

[15] The demand revenue target does not represent the total expected recovery from EDCM demand customers. Total expected recovery would include charges related to transmission exit charges.

of total asset value in the DNO area. The total EDCM revenue target would be the sum of individual cost allocations across EDCM demand customers.

3.17. To understand how the revenue target is calculated it is essential therefore to understand *which* costs are being allocated and *how* they are allocated to individual customers.

3.18. The DNO level costs and revenues allocated to individual EDCM demand customers are:

- Total direct operating costs
- Total indirect costs
- Total network rates
- Allowed revenue residual.

The allowed revenue residual is calculated as follows:

Allowed revenue residual = allowed revenue – [net recovery from EDCM generation] – [DNO's transmission exit charges] – [total direct operating costs] – [total indirect costs] – [total network rates]

For the avoidance of doubt, we note that only a proportion of the identified costs and the allowed revenue residual above end up in the demand revenue target.

3.19. Table 3.4 describes how these costs and the allowed revenue residual would be allocated to individual customers under the EDCM.

Table 3.4 Allocation of costs and allowed revenue residual to individual EDCM demand customers

Component	Amount allocated per EDCM demand customer
Direct costs	$\left[\frac{\text{Customer total asset value (£)}}{\text{DNO total adjusted asset value (£)}}\right]*[\text{DNO total direct costs (£)}]$
Indirect costs	$\left[\frac{\text{Customer total asset value (£)}}{\text{DNO total adjusted asset value (£)}}\right]*[\text{DNO total indirect costs (£)}]$
Network rates	$\left[\frac{\text{Customer total asset value (£)}}{\text{DNO total asset value (£)}}\right]*[\text{DNO total network rates (£)}]$
Allowed revenue residual	$\left[\frac{\text{Customer notional shared asset value (£)}}{\text{DNO total shared asset value (£)}}\right]*\left[\begin{array}{c}\text{Allowed revenue}\\\text{residual (£)}\end{array}\right]$

Where:

- Customer total asset value = notional shared asset value + sole use asset value
- DNO total adjusted asset value = (EHV assets value + (HV/LV assets value/0.68))

The 0.68 represents an adjustment that reflects higher operating expenditure intensity on HV/LV assets (see EDCM submission, paragraphs 271-274).

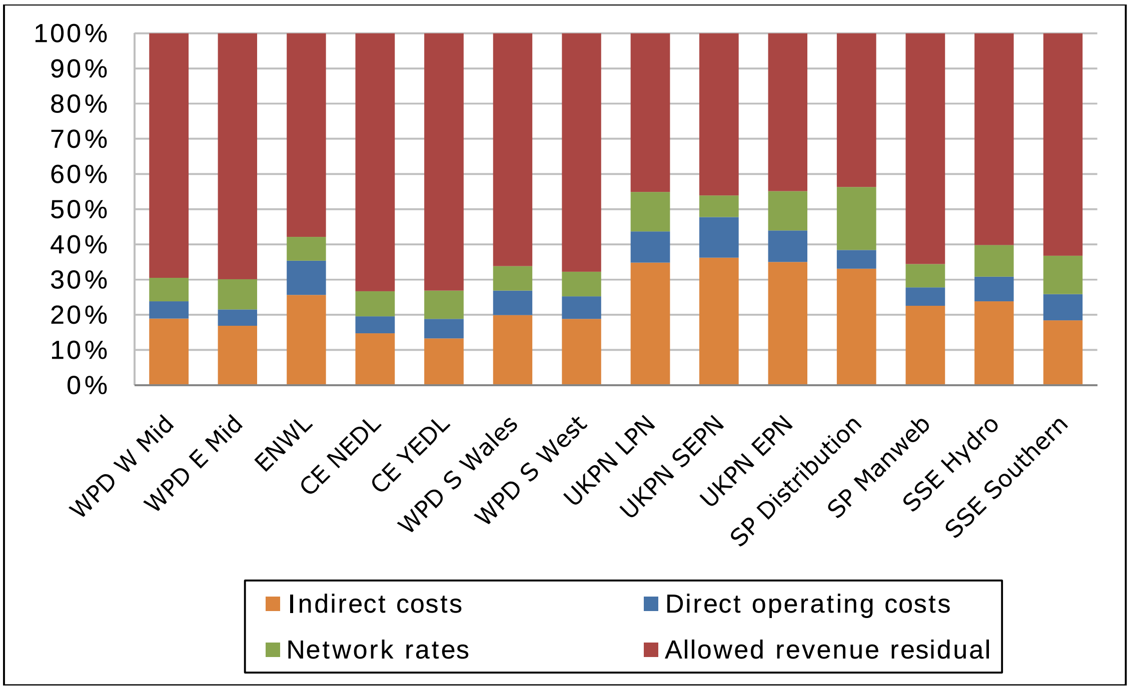
3.20. Essentially, each customer will be allocated a share of the cost/revenue item in proportion to the value of the relevant assets used to supply the customer out of the total asset value in the DNO area. These allocations are for the purpose of calculating a revenue target for demand customers collectively, not for the purpose of calculating individual DUoS charges. The revenue target is obtained by the aggregation of these allocations across all EDCM demand customers.

3.21. An important detail in the proposals is that the network use factors (NUFs) used in the determination of the revenue target may not always be the same as the ones used in the calculation of DUoS charges. NUFs play a role in the determination of the revenue target and DUoS charges through their use in the calculation of customers' notional shared assets. In the calculation of DUoS charges NUFs that are considered 'too high' or 'too low' are capped or collared respectively. In the determination of the revenue target, the DNOs propose not to apply caps and collars to NUFs.

3.22. We note that a customer's DUoS charge will typically not be the same as the amount of money allocated to the same customer in the process of determining the revenue target. This is because DUoS charges are calculated in a different way to the individual allocations described in Table 3.4. As noted in the section above, the first step in the calculation of DUoS charges is a 'bottom up' allocation of LRIC/FCP charges and other identified costs, irrespective of the revenue target. The revenue target is required only in order to scale these bottom up charges up or down to ensure that forecast recovery matches the revenue target.

3.23. Figure 3.4 shows a breakdown of the revenue target between the cost components and the allowed revenue residual by DNO. On average, the allowed revenue residual is the largest component (60%), followed by indirect costs (24%), network rates (9%) and direct operating costs (7%).

Figure 3.4 The EDCM demand revenue target by percentage of source component



Source: Ofgem analysis based on EDCM models in EDCM submission to Ofgem, April 2011

Our thoughts

3.24. We think that the discrepancy between the revenue that a customer brings into the demand revenue target and its DUoS charge (less the exit charge component) is, in principle, acceptable.

3.25. The discrepancy is a result of the fact that the allocation of revenues to individual customers to determine the revenue target is a 'top down' process, while customers' DUoS charges are calculated 'bottom up' using the forward looking LRIC/FCP charge component.

3.26. More importantly, the two processes have different objectives. The revenue target aims to represent a fair share of the allowed revenue attributable to EDCM demand customers, relative to other customer groups (EDCM generation and CDCM customers) and ensure that these customers do not pay too much or too little as a group. DUoS charges, on the other hand, aim to create efficient individual charges by reflecting all relevant costs - whether sunk, current or future costs – specific to that customer.

3.27. The report does not offer an explanation why the cap and collars are not applied in determining the revenue target. However, the report does explain the decision to apply caps and collars to NUFs when calculating individual charges in paragraphs 151-152:

> *151. In the site-specific approach, power flow analysis is used to match customers and the network assets. The power flow analysis, however, might in some cases indicate usage of network assets that may be affected by wider network design considerations unrelated to the needs of that customer.*
>
> *152. To address this, DNOs have decided to adopt a "cap and collar" approach to tackle the issue of outliers. Under this approach, the cap and collar would apply to the network use factors that in turn determine the value of shared network assets that are deemed to be used by each customer.*

3.28. Our understanding from this explanation is that the cap and collar limit the extent to which "wider network design considerations unrelated to the needs of that customer" may affect NUFs, and consequently charges, of individual customers.

3.29. The reason why NUFs are not capped or collared for the purpose of calculating the revenue target is that these "wider network considerations" affect the apportionment of notional assets to both CDCM and EDCM customers, such that their impact on NUFs (which are the notional assets of an EDCM customer divided by the notional assets of CDCM) is ambiguous (see Issue 5). In other words, while the impact of the "wider network consideration" could seriously distort individual NUFs, their effect on the revenue target as a whole is not systemic and need not be distortive to its size.

3.30. In fact, applying a cap and collar in the calculation of the revenue target may be inappropriate. Because of the asymmetric distribution of NUFs—it is bounded by zero from below but unbounded from above—applying a cap and collar in the derivation of the revenue target would typically reduce its size at the expense of CDCM customers.

3.31. Our initial assessment is that the method used for the calculation of the demand revenue target is reasonable.

Issue 2: principles guiding the use of capacity as a cost driver

The proposal

3.32. In the EDCM, the customer's capacity plays a major role as an allocation driver of costs. In fact, except for costs allocated on the basis of sole use assets (where capacity is implicit in the value of these assets), all other costs, revenues and the LRIC/FCP components are allocated on the basis of capacity. However, it is not always the same measure of capacity that is used as a cost driver. The "relevant capacity" for the allocation of cost to the customer will generally be determined according to the principle discussed below.

3.33. The EDCM considers costs over five network levels as described in paragraph 252 of the submission. Broadly, the network levels are the 132kV circuits; 132/33kV substations; 33kV circuits; 33/11kV substations and 132/11kV substations.

3.34. The EDCM generally considers different measures of capacity to be the relevant cost driver, depending on whether the costs are incurred at the customer's level of connection or at higher network levels. The EDCM follows the following principle:

- At the network level of connection, the customer's maximum import capacity is the relevant capacity for asset sizing, and therefore the relevant cost driver.
- At higher network levels, the customer's capacity used at system peak[16] is the relevant capacity for asset sizing, and therefore the relevant cost driver.

3.35. This principle is explained in the proposals in relation to the application of the local and remote LRIC/FCP charges to capacity and super-red consumption respectively:

> *81. We will apply two components of the charge 1 from FCP/LRIC to demand as follows:*
>
> *a) The component of charge 1 relating to parent and grandparent network groups under FCP, or the remote charge 1 relating to the relevant node under LRIC, are applied to consumption during a super-red time band defined by each DNO. Appendix 4 sets out the super-red time bands for each DNO area.* ***This is to reflect that, because of diversity, what drives network capacity and reinforcement costs is the consumption at the time where the network is most loaded, not the capacity or maximum consumption of the individual customer****.*
>
> *b) The component of charge 1 relating to the network group to which the customer is attached under FCP, or the local charge 1 under LRIC, is applied to the maximum import capacity.* ***This is on the basis that there is little diversity within a network group (or voltage level under LRIC), and therefore the network capacity required is best represented by using the capacity of the customer as a proxy****.*

3.36. In essence, what drives network costs is the extent that the customer consumes at the same time as other customers; otherwise there is spare capacity on the network. This is less applicable for assets that are close to the site and not shared by many customers, where how much a customer is allowed to consume is a better approximation as the driver of network costs.

[16] In the EDCM, capacity used at system peak is represented by consumption during the super-red time band.

3.37. Accordingly, the application of LRIC/FCP charge components into a customer's DUoS charge is done as follows:

[LRIC/FCP component of DUoS charge] =

$$\begin{bmatrix}\text{'Local' LRIC/FCP}\\ (\text{£/kVA})\end{bmatrix} * \begin{bmatrix}\text{Maximum import}\\ \text{capacity (kVA)}\end{bmatrix} + \begin{bmatrix}\text{'Remote' LRIC/FCP}\\ (\text{£/kVA})\end{bmatrix} * \begin{bmatrix}\text{Capacity at}\\ \text{system peak (kW)}\end{bmatrix}$$

Where capacity at system peak is forecast average capacity during the super-red time band of the charging year.

3.38. This principle is used not only in the application of LRIC/FCP charges, but also in the application of charges related to direct operating costs, network rates and 80 percent of the residual. In Issue 4 below, we explain in detail how this principle is applied in this context.

3.39. This is also demonstrated in Annex 2 paragraph 257 of the submission. For each customer category, maximum import capacity is the cost driver at the level of connection and peak time active power (kW) is the cost driver at higher voltage levels used by customers in the customer category.

3.40. DUoS charges include an element related to transmission exit charges that the DNO incurs for using the transmission company's substations (GSPs in England and Wales, and BSPs in Scotland). Except for customers connected directly to GSP substations (category '0000'), the GSP is a network level above the level of connection for all other customers. In line with the principle above, exit charges are calculated and applied to the customer's capacity at system peak. We note that for GSP connected customers exit charges are also applied to capacity at system peak. This is a deviation from the principle above.

Our thoughts

3.41. We accept this principle to be broadly in line with network planning practices. The network capacity required to cater for a customer's maximum import capacity is lower the more (demand) customers share the use of the asset. Broadly, network capacity will diminish the further the asset, or the network level, is from the customer's level of connection.

3.42. The methodology considers assets at the level of connection as 'close to the site', where the maximum import capacity is the cost driver, and assets at higher network levels as 'far from the site', where the capacity at system peak is the cost driver.

3.43. We recognise that this principle is an approximation. In practice, the amount of network capacity will depend on the specific circumstance of each connection. In some situations, a customer's maximum capacity may be the network capacity required on assets above its voltage level while for others, significant diversity will be applied to assets at the same voltage level. This principle aims to apply a common rule and obtain cost reflectivity. We think that this is a reasonable principle for charging purposes.

3.44. We note, however, that for domestic customers who are connected to the LV network, significant diversity is applied to determine the capacity of the LV assets required (ie LV cables are not sized on the basis of the sum of the maximum import capacity of all the customers supplied). For the sake of argument, assuming the maximum import capacity of a single house to be 20kW, the mains that supply ten such houses would not be sized to allow 20kWx10=200kW but substantially less than that.

3.45. We seek views on the assumption that at the voltage level of connection the maximum import capacity of customers is a good approximation for the required network capacity on assets at that voltage level.

Issue 3: allocation of indirects and a portion of the residual based on capacity

The proposals

3.46. Indirect costs within the revenue target and 20 per cent of the residual are allocated to customers based on a measure of their capacity, also referred to as a measure of their size. This allocation has been termed a 'fixed adder' allocation as it creates a fixed addition to each kVA of the customer's capacity.

3.47. The submission provides the following explanation for this choice:

> The choice to allocate indirect costs as a fixed adder:
>
> *143. The DNOs' direct operating costs and network rates are considered to be closely linked to network assets, and therefore best allocated using assets (shared and sole use) as the driver.*
>
> *144. DNO indirect costs are not considered to be closely linked to assets, but rather to customer size. As a result, indirect costs are allocated to customers on the basis of a composite proxy for customer size, i.e. 50 per cent of maximum capacity and peak-time consumption.*
>
> The choice to allocate 20 per cent of the residual as a fixed adder:
>
> *316. The DNOs believe that asset values are a fair and cost-reflective basis for allocating the bulk of the DNOs' allowed revenue. However, there are elements of the DNOs allowed revenue that do not seem suited to this method of allocation.*

317. In particular, the elements relating to the DNOs' tax allowances, pension deficit repair costs and expensed pension costs are considered better allocated as a fixed adder, rather than on the basis of site-specific assets.

3.48. In essence, indirect costs and a small proportion of the residual are deemed to be driven by customer size, or capacity, rather than the notional value of its assets.

3.49. The measure of customers' capacity to which the fixed adder applies is a combination of their maximum import capacity and capacity at system peak. A customer's 'capacity for fixed adder' is set out in the equation below:

$$\text{capacity for fixed adder (kVA)} = 50\% \times \begin{bmatrix}\text{maximum}\\ \text{import capacity}\end{bmatrix} + \begin{bmatrix}\text{historical capacity}\\ \text{at system peak}\end{bmatrix}$$

Where historical capacity at system peak is based on data from the most recent regulatory year for which data are available in time for setting charges.

3.50. The indirect costs within the EDCM revenue target and 20 per cent of the residual will be allocated to each customer based on its proportion of 'capacity for fixed adder' out of the sum of all 'capacities for fixed adder' across EDCM demand customers.

3.51. Table 3.3 shows that the size of these components accounts for around 30 per cent of final charges.

Our thoughts

3.52. Given that indirect costs are 'costs incurred undertaking activities which do not involve physical contact with system assets' (see Glossary of this document), we think it is reasonable not to allocate them based on notional asset values but rather based on the 'size' of the customer, measured in terms of capacity. Similarly, we accept the rationale provided in the submission that a proportion of the residual represents costs not associated with assets and that it is sensible to allocate them based on capacity in the same way as indirect costs.

3.53. We recognise that there may be arguments for using the maximum import capacity and for using capacity at system peak as the relevant measure of capacity for the purpose of allocating these components. Combining the two measures inevitably introduces some arbitrariness as to the weight each measure receives. The DNOs considered giving 'equal weights' to both components (ie replacing 50% by 100%) but ultimately felt that giving a heavier weight to capacity at system peak would provide a better basis for this quantity. In addition, the cost signal to avoid capacity at system peak would be stronger, which the DNOs considered a desirable charging policy.

3.54. We are broadly comfortable with the DNOs' proposal to allocate indirect costs and a small proportion of the residual based on customers' capacity.

3.55. We note, however, that the customer's capacity used for the fixed adder as given in the equation above is a summation of maximum import capacity, in kVA, and peak time capacity, in kW. We think this means reactive power is not taken into account. Our view is that peak time capacity *should* incorporate reactive power flows in order to account for the full cost implication of the customer's active power consumption during system peak. We invite stakeholder's views on this.

Issue 4: allocation of direct operating costs, network rates and a proportion of the residual based on notional shared asset value

The proposals

3.56. Direct operating costs and network rates within the revenue target, and 80 per cent of the residual are allocated to customers based on their 'notional asset value'.[17] Notional asset value (NAV) is the value, in modern equivalent asset value (MEAV),[18] of network assets that are used to supply electricity to a customer. Only shared assets are considered.

3.57. Table 3.3 shows that the three components allocated based on notional asset value represent about 44 per cent of final charges across all DNO areas.

3.58. The submission explains that direct operating costs and network rates are considered to be closely linked to network assets and therefore best allocated to customers on the basis of assets. Likewise, an estimated 80 per cent of the residual is assumed to be linked to assets and is therefore allocated based on asset value.

3.59. To calculate NAV per customer, the EDCM uses two specific inputs. The first is a set of average asset value per unit of capacity (kW) at each network level.[19] This input is called notional asset rate (NAR) expressed as £/kW. It is not customer specific.

3.60. The second is a set of 'network use factors' (NUFs), one for each network level at or above the level of connection. NUFs are customer specific and represent the proportion of the notional asset rate used by the customer. NUFs scale the notional asset rates upwards or downwards depending on the customer's use of assets relative to the average. NUFs are discussed in further detail under Issue 5.

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[17] In the determination of the EDCM revenue target, notional asset value is also the cost driver of indirect costs and the entire allowed revenue residual.
[18] For a definition of MEAV see glossary of this document.
[19] More precisely, it is the average value of assets at the network level, required to supply one unit of capacity (kW) used by lower voltage customers.

3.61. NARs and NUFs are combined with the customer's maximum import capacity and capacity at system peak to calculate notional asset value as set out in the equation below:[20]

$$\begin{bmatrix}\text{notional asset}\\ \text{value (£)}\end{bmatrix} = [\text{NAR}]_c * [\text{NUF}]_c * \begin{bmatrix}\text{maximum}\\ \text{import capacity}\end{bmatrix}$$

$$+ \sum_{ac} \left\{ [\text{NAR}]_{ac} * [\text{NUF}]_{ac} * \begin{bmatrix}\text{capacity at}\\ \text{system peak}\end{bmatrix} \right\}$$

where "c" is the level of connection and "ac" is an index for network levels above connection.

3.62. Direct operating costs and network rates within the revenue target, and 80 per cent of the residual, will be allocated to every EDCM demand customer according to its share of NAV out of total NAV across EDCM demand customers.

[20] This equation does not consider adjustments for losses.

Box 3.1 Notional asset value

This provides an example of the calculation of NAV. It also shows how it is used to allocate direct operating costs, network rates and 80 per cent of the residual.

Customer information	**DNO information**
Level of connection: 33kV circuits (customer category '1110') Maximum import capacity = 10MVA System peak capacity = 5MVA NUF at 33kV = 2.4 NUF at 132/33kV = 1 NUF at 132kV = 0.4	Notional asset rate at 33kV = £80/kW Notional asset rate at 132/33kV = £100/kW Notional asset rate at 132kV = £200/kW Direct operating costs and network rates in the revenue target plus 80 per cent of the residual = £5m

Step 1: calculate the customer's notional shared asset value

	Network level				
	132kV	132/33kV	33kV	33/11kV	132/11kV
Relevant capacity (MVA)	5	5	10	-	-
Network use factors	0.4	1	2.2	N/A	N/A
Notional asset rate (£/kW)	200	100	80	N/A	N/A
NAV at network level (£)	£0.4m	£0.5m	£1.76m	-	-
Customer's NAV = £0.4m + £0.5m + £1.76m = £2.66m					

Step 2: repeat the calculation for every EDCM demand customer. Assume the total notional asset value across all EDCM demand customers is £200m.

Step 3: calculate the share of the customer's NAV out of total NAV in the DNO area:

£2.66m/£200m=1.33%

Step 4: allocate annual direct operating costs, network rates and 80 per cent of the residual to the customer's DUoS charge:

1.33%*£5m=£66,500

This amount will be applied to maximum import capacity at a rate of £6.65/kVA/year or 1.8p/kVA/day.

Our thoughts

3.63. Given that direct operating costs are ‘costs incurred undertaking activities which involve physical contact with system assets’ (see Glossary of this document), we think it is reasonable to allocate them on the basis of notional asset values. Similarly, we agree with the rationale provided in the submission that the majority of the residual represents costs associated with assets.

3.64. Throughout the development of the EDCM there has been a debate whether allocation of asset related cost items should be on the basis of site-specific assets (“the site-specific approach”) or average voltage level assets (“the voltage level approach”). In their December 2010 consultation, the DNOs presented both approaches. In their formal submission, the DNOs decided to adopt the site-specific approach as the majority of DNOs deemed the resulting charges more cost-reflective.

3.65. We think that there are arguments on both sides – for the site-specific approach and for the voltage level approach. Against a site specific approach there is a practical argument that any method to assign individual notional asset values to customers is inevitably complex and involves a number of assumptions. The method proposed is no exception. Furthermore, the specific assets used to supply electricity to a customer are typically not under the customer’s control but rather a result of an organic evolution of the network that could have taken different shapes. Following from that, there may be an argument that the service provided to a customer is the availability of a network that allows the customer to connect at an appropriate voltage level rather than the specific assets through which current flows to the customer.

3.66. On the other hand, we recognise the argument that the site-specific approach endeavours to be more cost-reflective by taking into account the specific assets used for the electricity supply of a customer. This may be particularly useful for customers who use a small proportion of network assets at some voltage level.

3.67. We note also that the site-specific approach, through the use of NUFs, is potentially more volatile than the voltage level approach. The submission proposes to recalculate and update customers’ NUFs on an annual basis. Year on year volatility in a customer’s NUFs may be induced by the customer’s behaviour but also by other customers’ behaviour. We consult on options to mitigate NUF volatility under Issue 21.

3.68. On balance, we think that where the DNOs have landed is reasonable. The EDCM uses site-specific notional asset value only for the allocation of costs that are deemed to be directly related to assets and only for the allocation of a portion of the residual. Costs that are deemed not to be directly related to assets are not allocated per notional asset values. Moreover, NUFs used for the determination of notional asset values are capped and collared to mitigate unintended consequences on individual charges.

Issue 5: calculation of network use factors

The proposals

3.69. A network use factor is the value of assets, at a given network level, used for the supply of a unit of power (kW) to a specific EDCM demand customer, relative to the average value of assets at the same network level used for the supply of a unit of power to CDCM customers.

$$NUF_{i,j} = \frac{\text{[value of level j assets used for the supply of 1kW of customer i]}}{\text{[value of level j assets used for the supply of 1kW of CDCM customers]}}$$

where i is a customer and j is a network level.

3.70. Each EDCM demand customer has a different NUF for each network level at or above its level of connection. NUF values have the following interpretation:

- NUF < 1: the customer uses a lower value of assets per kW than CDCM customers
- NUF = 1: the customer uses the same value of assets per kW as CDCM customers
- NUF > 1: the customer uses a higher value of assets per kW than CDCM customers.

3.71. The submission proposes to calculate NUFs using a power flow analysis. A detailed description of the proposal can be found in sections 29-30 of appendices 2(a) and 2(b) of the submission.

3.72. An important aspect of the proposal is that the power flow fully apportions the full replacement value (MEAV) of every asset[21] between the customers that 'use' the asset under normal running conditions during the 'maximum demand scenario'. The portion of asset value attributed to customer i is given by:

$$\begin{bmatrix}\text{portion of asset}\\ \text{attributed to}\\ \text{customer i (£)}\end{bmatrix} = \frac{\begin{bmatrix}\text{asset power flow attributed}\\ \text{to customer i (kW)}\end{bmatrix}}{\begin{bmatrix}\text{sum of attributed power flows}\\ \text{of all users of the asset (kW)}\end{bmatrix}} * \begin{bmatrix}\text{annuitised MEAV}\\ \text{of asset (£)}\end{bmatrix}$$

3.73. For each EDCM demand customer the sum of all portions across all assets used to supply it at a given network level will add up to the numerator of its NUF at that level. We discuss the implications of this method of calculation below.

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[21] The EDCM submission often uses the term "branch" instead of "asset", in particular in the context of power flow analysis. The term "branch" is defined in Appendices 2(a) and 2(b) of the EDCM submission. In essence, a branch is a continuum of assets without a tee-off point along it, so that the active power flowing into one end equals the active power flowing out of the other end of the branch less any losses within the branch.

3.74. The submission proposes to apply a cap and collar to NUFs because "the power flow analysis … might in some cases indicate usage of network assets that may be affected by wider network design considerations unrelated to the needs of that customer" (EDCM submission, paragraph 151). The cap and collar is common across all DNO areas and is updated every three years based on the previous three years of data (EDCM submission, paragraphs 326 to 331).

Our thoughts

3.75. We identified two issues related to the calculation of NUFs. We discuss each in turn.

No consideration of asset usage under contingency events

3.76. The power flow analysis underlying the calculation of NUFs considers only normal running conditions. As a result, the network use factor represents the proportion of asset value used by a given EDCM customer <u>under normal running conditions</u>, relative to the average asset value used by CDCM customers <u>under normal running conditions</u>.

3.77. The implication is that assets used by a customer only under outage situations do not enter the calculation of NUF and do not affect its value. Consequently, the customer's notional asset value reflects only shared assets used under normal running conditions.

3.78. On this concern, we think that the fact that the method is applied in a consistent manner across all the nodes of the EHV network (EDCM nodes and CDCM nodes at primary substation) should mitigate the potential for non-reflective NUF values.

3.79. It is possible that if the power flow was run under normal running conditions and under contingencies the effect on a customer's NUF and notional asset value is ambiguous. On the one hand, the contingency analysis would identify more assets 'used' by the customer, pushing its NUF higher. On the other hand, the contingency analysis would reduce the portion of assets allocated to the customer because more customers are now found to be using the asset. This will push the NUF lower.

3.80. On balance, we think that it is a reasonable charging policy to base the calculation of NUFs on an analysis of the network only under normal running conditions.

No provision for spare capacity

3.81. The expression in paragraph 3.69 implies that the *full annuitized value* of each asset is *fully apportioned* to customers based on their respective flow (or, respective impact on flow) through the asset in the maximum demand scenario.[22]

3.82. We think that this may not be appropriate if the asset has spare capacity above what is required to provide for maximum demand and security of supply. Arguably, the spare capacity is not there for the customers currently using the asset; rather it represents general cost of running a network and may have wider benefits to all customers. We think there might be an argument that where there is spare capacity on assets that are not used by anyone, it might instead be appropriate to recover the associated costs from all network users, through the scaling process.

3.83. Allocating the full value of the asset, only the customers currently using the asset would increase their NUF and ultimately their DUoS charge. Effectively, only the customers currently using the asset recover the costs associated with its spare capacity. This may discourage small customers from connecting to assets with significant spare capacity where no reinforcement would be required. This does not appear to be a cost-reflective signal and would be in contrast to the LRIC/FCP cost signal.

3.84. For example, the spare capacity may be a result of historical circumstances – the asset may have been sized for a large customer that is no longer connected. Alternatively, it can be due to normal network planning practices, which typically allow for spare capacity to cater for future growth.

3.85. By way of an example, if two customers use 10MW and 20MW of an asset capacity under the maximum demand scenario they will be allocated 33 and 66 per cent of the asset value respectively by the proposed method in the EDCM. The asset rated capacity[23] is irrelevant for this allocation. An alternative method could be to

[22] The crucial step in the derivation is step four of the "Incremented method" (EDCM submission, Appendix 2(a) and 2(b), paragraph 30.6) where it is specified that the full value (second sentence of the quotation) of the asset is fully apportioned (first sentence of the quotation) amongst customers found through the power flow analysis to be using the asset:

> *Each nodal demand's proportionate usage of a branch is determined as the ratio of 'MW usage' of the branch by the nodal demand to the 'total MW usage' of the branch. This ratio [the ratio given by the expression in paragraph 3.69] is multiplied by the annuitised MEAV of the branch to create a £/ annum usage of the branch by the particular node.*

[23] The rated capacity of the branch is the specified maximum capacity of the branch.

replace the denominator in the expression in paragraph 3.69 by the rated capacity of the asset. If the same asset has a rating of 100MW, the customers will be allocated ten and 20 per cent of the asset value respectively by the alternative method.

3.86. It can be argued that the alternative method does not allocate ‘enough’ of the asset to its users, as it does not consider capacity required for security of supply. We think that a more proper calculation of network use factors would lie somewhere between the two approaches. We would be interested in feedback from the DNOs and other stakeholders on which approach is deemed to result in a fairer allocation of costs.

3.87. We note that there are two mitigating measures to the issue of spare capacity. The first is the cap and collar applied to NUFs. The cap limits the value of a NUF and therefore the potential impact of spare capacity on customers’ charges. We note that a cap is an indiscriminate measure and it may limit NUF values that have not been caused by spare capacity.

3.88. The second is the fact that spare capacity will tend to inflate not only the value of assets deem to be used by an EDCM customer but also the value of assets deemed to be used for the supply of CDCM customers. Since NUFs are obtained by dividing the former by the latter (as shown in the expression in paragraph 3.69), the effect of spare capacity on the value of NUFs is ambiguous.

3.89. While this does not mean that the issue of spare capacity is not material for individual customers, it clearly mitigates its effect.

3.90. In view of our concerns, we consider making it a condition of our approval of the EDCM that DNOs investigate the implication of the issue raised above, its materiality and whether the current cap in place is an effective measure. If necessary, we would request DNOs to review the derivation of network use factors and bring forward proposals for addressing the issue raised above.

3.91. Despite the potential downsides of the method to calculate NUFs, we recognise that other approaches have other disadvantages of their own. To date, we have not been presented with evidence that issues with the current method have a material implication. We also recognise that the cap and collar and the benchmarking against CDCM may help to minimise these situations. On balance, we think that the proposal is reasonable subject to the condition above.

Issue 6: allocation of the residual

The proposals

3.92. The ‘residual’ is the difference between the revenue target for EDCM demand customers and the amount of money recovered through the ‘bottom up’ charges, ie LRIC/FCP charges and charges related to the pre-allocated costs. Specifically, it is given by the following equation:

$$\begin{bmatrix}\text{Scaling}\\ \text{residual}\end{bmatrix} = \begin{bmatrix}\text{Revenue}\\ \text{target}\end{bmatrix} - \begin{bmatrix}\text{Total revenue}\\ \text{from LRIC/FCP}\\ \text{charges}\end{bmatrix} - \begin{bmatrix}\text{Total revenue from}\\ \text{charges related to}\\ \text{direct operating costs,}\\ \text{indirect costs}\\ \text{network rates}\end{bmatrix}$$

3.93. Table 3.3 shows that the residual typically accounts for a substantial percentage of final charges but can vary widely. On average across all DNOs it account to 37 per cent of final charge but in a number of DNO areas the percentage is around 50. In SP Distribution, the residual is negligible due to the relatively large recovery of revenue from FCP charges.

3.94. The EDCM submission proposes to split the residual into a portion that would be allocated based on capacity and a portion that would be allocated based on notional assets. The proposed split is common across all DNO areas: 20 per cent of the residual allocated to individual customers based on their capacity and 80 per cent is allocated based on their notional shared assets.

3.95. Annex 5 of the submission provides an explanation for the proposed split.

> *316. The DNOs believe that asset values are a fair and cost-reflective basis for allocating the bulk of the DNOs' allowed revenue. However, there are elements of the DNOs allowed revenue that do not seem suited to this method of allocation.*
>
> *317. In particular, the elements relating to the DNOs' tax allowances, pension deficit repair costs and expensed pension costs are considered better allocated as a fixed adder, rather than on the basis of site-specific assets.*

3.96. Using data from our recent distribution price control review the DNOs calculated the proportion of the three elements mentioned above out of their allowed revenue and came to the conclusion:

> *324. The DNOs believe that a GB-wide figure of 20 per cent would be a reasonable estimate of the average proportion of residual revenue that corresponds to tax allowances, pension deficit repair and pension cost expensed, and therefore the proportion of residual revenue that should be allocated using a fixed £/kVA adder across all DNO areas.*

3.97. The proposal is to use this 80/20 split 'hardcoded' into the methodology and not to update it on a periodic basis.

Our thoughts

3.98. We consider it reasonable that the residual is divided between asset-based and non asset-based components, and that these components are allocated to customers based on their respective cost drivers. We recognise that the majority of DNOs revenue can be attributed, to a greater or lesser extent, to assets.

3.99. Like most aspects of the methodology, the split is naturally an approximation. The split is based on classification of costs as asset-related or non-asset related based on broad categories, when in fact sub-categories could have different drivers. Moreover, an issue to consider is whether the split should be DNO specific or, as proposed, a “GB-wide figure”.

3.100. Nonetheless, the evidence provided by the DNOs for the 80/20 split is reasonable and the variation between DNO areas is relatively small. Given the 80/20 split is an approximation, we think that it is better to have a clear and transparent split across DNOs, rather than a DNO-specific number, or a split that is re-calculated and updated annually. We would expect the DNOs to keep this split under review to make sure it remains fit for purpose.

Issue 7: customer categories

The proposals

3.101. The EDCM covers five levels of network assets: 132kV circuits[24]; 132/33kV substations[24]; 33kV circuits; 132/11kV substations and 33/11kV substations. The DNOs have customers that use different combinations of network levels. For example, a customer connected to 33kV circuits typically uses the 132/33kV and 132kV network levels, but could also be connected directly to a transmission substation (eg 275/33kV) in which case the customer uses *only* the 33kV circuits of the distribution network.

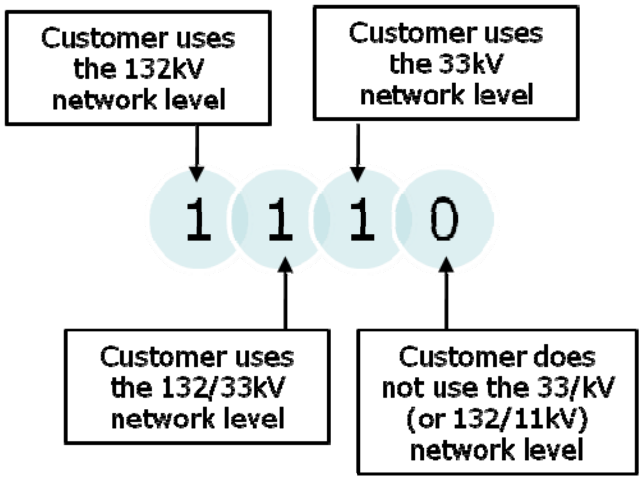
3.102. The EDCM proposes to use 15 customer categories to classify demand customers based on the network levels that they use (see Annex 2 in the submission). The EDCM does not require a classification of customer category for generation customers.

3.103. The submission proposes to use four-digit binary codes (except one code that uses the digit “2”) to represent customer categories. The four-digit codes for a customer category can be interpreted as follows: the first digit on the left denotes whether the customer uses 132kV circuits; the second denotes whether the customer uses 132/33kV substations; the third denotes whether the customer uses 33kV

[24] England and Wales only.

circuits and the fourth denotes whether the customer uses either 132/11kV or 33/11kV substations. An example is set out in Figure 3.5.

Figure 3.5 Interpretation of customer category coding: a customer connected at the 33kV network level that uses all network levels above it



3.104. Customers may be deemed to use up to four network levels. That would be the case of a customer connected at the lower busbar of a 33/11kV substation that is fed from a 33kV network, which in turn is fed from a 132kV network. This customer category is denoted ‘1111’. Customers may be deemed not to use any network level. This would be the case of customers connected directly to the GSP, denoted ‘0000’.

3.105. The large number of customer categories comprehensively covers all non-standard network connection. For example, category ‘0001’ stands for customers connected at a primary substation (33/11kV) without using any other network level and category ‘0101’ stands for customers connected at a primary substation and the only other assets they use are of a 132/33kV substation without using any network assets .

3.106. Modelling all possible customer categories is an attempt to ensure cost reflectivity by charging each customer only in respect to network levels that they use. For example, the ‘0001’ customer described above need not be charged in respect of 33kV assets, 132kV assets or 132/33kV substation assets but only in respect of 33/11kV substation assets.

3.107. Table 3.5 shows the number of customers within each customer category for each DNO area. Several of the customer categories, especially those that involve a DNO-owned substation ‘co-located’ with a GSP (categories 0100, 0110, 0001, 0002, 0111, 0101 and 1101) have very few customers.

Table 3.5 Customer categories for demand customers

DNO	0000	1000	1100	0100	1110	0110	0010	0001	0002	1001	0011	0111	0101	1101	1111
WPD W Mid	2	10	5	-	5	-	-	-	-	2	-	1	-	-	5
WPD E Mid	1	12	11	1	22	-	-	-	-	-	-	1	-	-	21
ENWL	7	17	10	-	22	1	-	-	-	3	-	-	-	1	19
CE NEDL	2	6	5	-	8	-	7	-	-	1	4	-	-	-	5
CE YEDL	5	12	16	-	12	-	5	-	1	-	10	-	-	-	41
WPD S Wales	3	14	8	1	21	1	1	-	-	7	1	-	-	-	4
WPD S West	-	3	7	-	26	-	-	-	-	-	-	-	-	-	15
UKPN LPN	14	7	3	-	-	-	-	1	-	4	1	-	-	-	-
UKPN SEPN	6	9	23	1	3	-	-	-	-	-	-	1	-	-	4
UKPN EPN	6	28	20	2	24	1	-	-	-	1	2	1	-	-	19
SP Distribution	35	-	-	-	-	-	23	-	-	-	11	-	-	-	-
SP Manweb	2	11	15	-	40	-	-	-	-	-	-	-	-	2	134
SSE Hydro	29	-	-	-	-	-	95	-	-	-	10	-	-	-	-
SSE Southern	5	11	27	1	28	1	-	-	-	1	-	-	-	1	9
Total	**117**	**140**	**150**	**6**	**211**	**4**	**131**	**1**	**1**	**19**	**39**	**4**	**-**	**4**	**276**

Source: EDCM models in EDCM submission to Ofgem, April 2011

Our thoughts

3.108. We are not certain that the model requires customer categories to classify customers based on the network levels they use. The model calculates a set of network use factors for each demand customer so that each customer has a NUF associated with each of the five asset levels described above. This set of NUFs essentially delineates the network levels that the customer uses – if the customer uses a specific network level, its corresponding NUF would be positive. If the customer does not use a network level, its corresponding NUF would be zero.

3.109. In practice, the set of NUFs does not always correspond to the customer category in every case. From our examination of the EDCM models submitted to us, we found that in some cases a network use factor may be positive for a network level that, according to the customer category, the customer does not 'use'. We urge the DNOs to explain why these cases arise and why customers should not be charged for network levels that the power flow reveals that they do, in fact, 'use'.

3.110. We note also that in some cases the power flow calculates a positive network use factors at network levels below the level of the customer's connection. This can be the case when a customer is supplied through distributed generation below its level. The EDCM does not propose to charge customers for use of assets below their level of connection. Under the "voltage level" approach it is reasonable to assume that customers only use their network level of connection and higher network levels. However, when modelling the specific assets used by each customer we are unclear as to why this assumption needs to be maintained. We urge the DNOs to explain their decision not to charge for use of assets below the network level at which the customer is connected.

3.111. It may be better practice to ensure that the customer categories are consistent with their corresponding set of NUFs. This would help avoid misclassification of customers, which can have material consequences on their charge.

4. Charging proposals for generation customers

Chapter Summary

In this chapter, we summarise the EDCM proposals for charging of generation customers, highlight key issues and principles, and set out our initial thinking.

Question 4.1: Do you agree with our proposal to modify the generation revenue target in order to avoid double charging for operations and maintenance costs on sole use assets? This issue aside, do you agree with our view that the approach to calculating a generation revenue target is reasonable?
Question 4.2: Do you agree with our assessment that the approach to scaling is reasonable?
Question 4.3: Do you think it is appropriate for only units exported by non-intermittent generators during the super-red time band to be eligible for credits?
Question 4.4: Do you agree with our proposal that intermittent DG should be eligible for credits as they are deemed to provide network benefits under ER P2/6? If they do become eligible for credits, should the credits only relate to units exported during the super-red time band or is a single credit rate to all units exported more appropriate?
Question 4.5: On import charges for generation dominated mixed import-export:

- Do you agree with our suggested alternative to using the collar of the network use factor for the calculation of the import tariff?
- Do you think that the methodology is appropriate for demand customers connected to generation dominated assets?

Question 4.6: Are there any other generation specific issues that you think we should consider as part of our decision?

Overview of the methodology

4.1. Broadly, the EDCM calculates distribution use of system (DUoS) charges for generation customers (customers that export electricity from the distribution network) as follows:

(i) LRIC or FCP charges are applied to the generator’s maximum export capacity.

(ii) The EDCM calculates a ‘revenue target’ – an amount of money deemed attributable to EDCM generation customers (see Issue 8). The revenue target represents the majority of revenue that the DNO forecasts it will recover from generation customers.

(iii) Total recovery from LRIC/FCP charges is compared against the revenue target. The residual is allocated to customers based on their maximum export capacity (see Issue 9).

(iv) Charges related to the generator's sole use assets (in respect of direct operating costs and network rates) are added to the tariff as a fixed charge (see Issue 17).

(v) LRIC or FCP credits are applied to generation export during the super-red time band for non-intermittent generation (see Issue 10).[25]

4.2. Table 4.1 describes the cost/credit driver of each component allocated into the generation DUoS charge.

Table 4.1 Allocation driver of each cost, credit and revenue component allocated to DUoS charges of EDCM generation customers

	Allocation driver		
Source of charge	Maximum export capacity	Sole use assets value	Export at system peak (non-intermittent only)
LRIC/FCP model	✓		✓
Direct costs		✓	
Network rates		✓	
Residual	✓		

4.3. For the allocation of generation credits, 'export at system peak' refers to generation export during the super-red time band within the charging year (see Issue 10). The super-red time band covers the season and time of day when simultaneous maximum demand on the network is most likely to occur in the relevant DNO area.

Overview of the tariff structure

4.4. Under the EDCM, generation customers will be subject to tariff components as set out in Table 4.2 on the next page.

[25] Non-intermittent generation is a "[g]eneration plant where the energy source for the prime mover can be made available on demand" (Engineering Recommendation P2/6).

Table 4.2 Generation tariff components

Tariff component	Unit	Application	Comments
Fixed charge	£/day	Applied as a fixed charge	Reflects sole use asset charge for direct operating costs and network rates
Export capacity charge	£/kVA/day	Applied to the maximum export capacity	Reflects both local and remote elements of the FCP/LRIC charge 2, the generation scaling fixed adder and transmission exit credits for qualifying generators
Generation credit	£/kWh (negative)	Applied to units produced during the DNO's super-red time band	Reflect both local and remote elements of the FCP/LRIC charge 1

Source: Based on tables 2 and 4 of the EDCM submission

4.5. The fixed charge is for costs associated with the generator's sole use assets. Two types of costs are allocated based on the customer's sole use asset value: direct operating costs and network rates. The methodology for sole use asset charges is common to demand and generation and is in Issue 17.

4.6. The export capacity charge comes from two sources. The first component is derived from the LRIC or FCP methodologies in respect of future generation-driven reinforcement. The second component is a 'scaling' component that ensures forecast revenues are equal to the revenue target from generation. The scaling component is in the form of a fixed adder (£/kVA), which can be positive or negative. The calculation of the revenue target and its rationale are discussed below under Issue 8.

4.7. The generation credit is derived from the LRIC or FCP methodologies. The credit reflects deferred future reinforcement works due to the generation. The EDCM does not apply credits to intermittent generation. (We discuss this aspect of the proposal later in this chapter under Issue 11.) Generation credits are applied to units exported during a DNO specific time band called 'super-red'. The methodology for the calculation of generation credits is discussed later in this chapter under Issue 10.

4.8. The annual generation UoS charge is given by the following equation[26]

GDUoS charge (£) = [Fixed charge (£)]

+ [Capacity charge (£/kVA)] * [Maximum export capacity (kVA)]

[26] In addition to this, a credit for transmission exit will apply to "generators that have an agreement with the DNO, the terms of which require the generator, for the purposes of P2/6 compliance, to export power during supergrid transformer (SGT) outage conditions''.

+ I*[export credit (£/kWh)]*[units exported during super-red hours (kWh)]

Where I = 1 for non-intermittent generation and 0 otherwise.

4.9. In addition to the above, customers that exceed their maximum export capacity would be charged for the excess at the same rate as the export capacity charge for capacity within the allowed limit. The charge will apply for the duration of the month in which the breach occurs (except for sites that operate subject to grid code requirements for generation). More details are provided in paragraphs 177 to 183 of the EDCM submission.

4.10. Table 4.3 shows total revenue recovered from generation by tariff component for each DNO area. In all bar one DNO area, UKPN LPN, total generation charges exceed total generation credits. It is noteworthy that total revenue from sole use asset charges in the two Scottish DNO areas, SSE Hydro and SP Distribution, is significantly higher than in all other areas. This is mainly because on average, generators in Scotland use more sole use assets than in England and Wales.

Table 4.3 Recovery from EDCM generation by tariff component

DNO	Total fixed charges (£)	Total capacity charges (£)[1]	Total generation credits (£)	Total generation recovery (£)
WPD W Mid	47,586	406,086	-44,617	409,055
WPD E Mid	164,669	1,728,607	-960,827	932,449
ENWL	179,373	1,874,674	-176,678	1,877,369
CE NEDL	79,028	1,050,125	-140,231	988,922
CE YEDL	185,587	1,111,825	-45,314	1,252,098
WPD S Wales	129,285	1,008,371	-111,893	1,025,763
WPD S West	106,284	451,920	-230,124	328,079
UKPN LPN	24,043	207,577	-239,033	-7,413
UKPN SEPN	66,494	1,075,280	-446,060	695,714
UKPN EPN	113,915	2,298,151	-1,497,432	914,635
SP Distribution	905,855	1,565,713	-390,672	2,080,897
SP Manweb	366,977	1,958,042	-1,559,964	765,056
SSE Hydro	944,908	1,406,094	-20,463	2,330,539
SSE Southern	114,856	1,028,493	-220,263	923,086

[1] These capacity charges are equal to the generation revenue target for each DNO
Source: EDCM models in EDCM submission to Ofgem, April 2011

4.11. In the remainder of this chapter we discuss issues that we wish to highlight and would welcome stakeholder feedback on. We present the DNOs' proposal on the issue, discuss it and provide our thoughts.

Issue 8: the generation revenue target

4.12. The generation revenue target is a sum of money that each DNO sets out to recover from its EDCM generation customers through capacity charges.

4.13. The generation revenue target does not represent the total recovery from generation customers. The total recovery will include recoveries from fixed charges less any generation credits, both of which are completely separate from the revenue target.

The proposals

4.14. The DNOs' proposal is based upon the DPCR5 DG incentive framework.[27] The DG incentive revenue allows the DNOs to recover capital and operating expenditure related to generators connected after 2005.

4.15. The proposal calculates the generation revenue target in two steps:

(i) An operating and maintenance (O&M) allowance for generators connected before 2005 is added to the DG incentive revenue (which just covers post-2005 DG). This matches the £1 per kW[28] used in the DG incentive for post-2005 generators.

(ii) The amount obtained in the first step above is then multiplied by the share of generation capacity in the DNO area made up by EDCM generators.

4.16. In addition, a 'sole use asset factor' is applied to pre-2005 generation capacity. This factor scales down the O&M charging rate. The value of the sole use asset factor is generally very close to unity (0.98 on average across DNOs) and therefore its impact on the revenue target is insignificant. The EDCM report does not explain the purpose of the factor. However, in informal communication with the DNOs they explained that the purpose of the sole use asset factor was to avoid possible double charging of O&M costs relating to sole use assets.

4.17. The EDCM revenue target is calculated as follows:

EDCM generation revenue target =

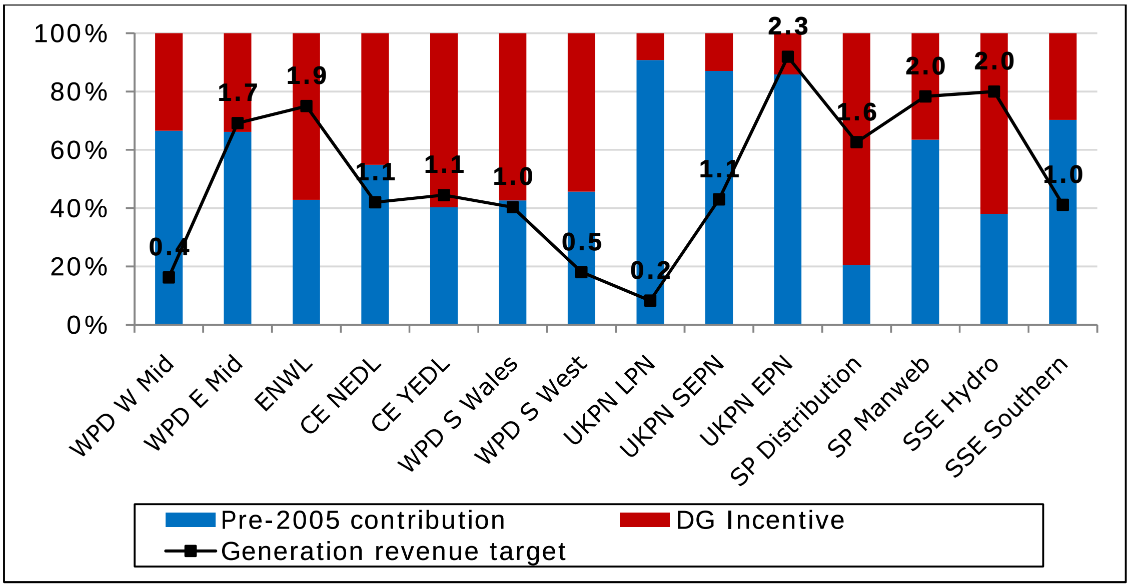
$$\frac{\text{EDCM generation capacity}}{\text{Total generation capacity}} * (\text{DG incentive revenue } + s * \text{O\&M rate} * \text{ pre-2005 DG capacity})$$

[27] See Ofgem (2009): 'Electricity Distribution Price Control Review Final Proposals – Incentives and Obligations'.
[28] In 2007-08 prices, adjusted by the retail prices index (RPI).

where "s" is a sole use asset factor.

4.18. Figure 4.1 shows the size of the generation revenue target and the split of the revenue target between the DG incentive, which is related to post-2005 connected DG, and the O&M allowance related to pre-2005 connected DG.

Figure 4.1 The generation revenue target (£m) and the proportion of its constituents



Source: EDCM models in EDCM submission to Ofgem, April 2011

4.19. We note that the concept of a revenue target for generation was introduced after the DNOs' June 2010 consultation.

Our thoughts

4.20. The revenue target should reflect the portion of the DNO's allowed revenue attributable to EDCM generation. The purpose of the revenue target is to ensure that final charges for generators are cost-reflective in terms of the price control settlement. This is the same reason why charges for demand customers, both in the EDCM and in the CDCM, are scaled to their respective revenue targets to ensure the full recovery of the regulatory revenue allowance.

4.21. Under the EDCM, sole use assets charges do not contribute to the recovery of the generation revenue target. According to Charge Restriction Condition (CRC) 11 of the electricity distribution licence, the O&M adjustment to the DG incentive is an "adjustment [...] in respect of the operational and maintenance costs of Total Capex for DG" where Total Capex for DG means "the sum of all costs directly incurred by the licensee in relation to the installation or reinforcement of electric lines or electrical plant necessary for the connection of [...] DG" (CRC11, Part D). This suggests that the O&M rate includes O&M costs associated with all assets – shared and sole use. Using the O&M rate to determine the revenue target while charging operating costs on sole use assets separately could lead to allegations of double charging for O&M on sole use assets. The sole use asset factor is the DNOs' proposal to redress such issues.

4.22. We think that a generation revenue target is desirable in order to ensure that EDCM generation, as a group, pays a fair share of allowed revenue.

4.23. We recognise that in a network that is largely demand-dominated, generation flows do not drive network costs to the same extent as demand flows do. For that reason, the methodology used to calculate a revenue target for demand—where assets are allocated between EDCM and CDCM customers based on their respective usage of the assets—may not lend itself to calculating a revenue target for generation.

4.24. We are unclear why the sole use asset factor is used to scale down the O&M rate that is applied to pre-2005 DG capacity but not to post-2005 DG capacity. If its purpose is to avoid double charging that results from the application of an unscaled O&M rate and a separate operating charge related to sole use assets, then it would seem appropriate to scale down the O&M rate in both occasions where it features in the calculation of the generation revenue target.

4.25. In informal communication with the DNOs they argued that applying the scaling factor to post-2005 DG would involve reworking the DG incentive formula (because the O&M rate is a component that sits within the DG incentive) and that this was considered “unnecessarily complicated”. They also argued that reducing the DG incentive could cause some of the actual DG incentive revenue being smeared across CDCM and EDCM demand customers.

4.26. We ask DNOs to re-consider the issue. We think that this adjustment should not involve much complication. Moreover, if the purpose of the adjustment is to avoid charging twice for operating costs associated with sole use assets we fail to see how this adjustment could unduly smear costs to other customers. Subject to stakeholder responses, we would consider placing a condition on our approval to ensure this is corrected.

4.27. Subject to our concern above, we think that the proposed method for calculating a generation revenue target is reasonable.

Issue 9: scaling

The proposals

4.28. Scaling is a mechanism that ensures full recovery of the generation revenue target through generation use of system charges.

4.29. The DNOs proposal involves calculating a "fixed adder"—a fixed £/kVA amount—that will make up the shortfall or excess between the generation revenue target and forecast recovery through LRIC/FCP charges. Note that in the case of excess recovery the fixed adder would be negative.

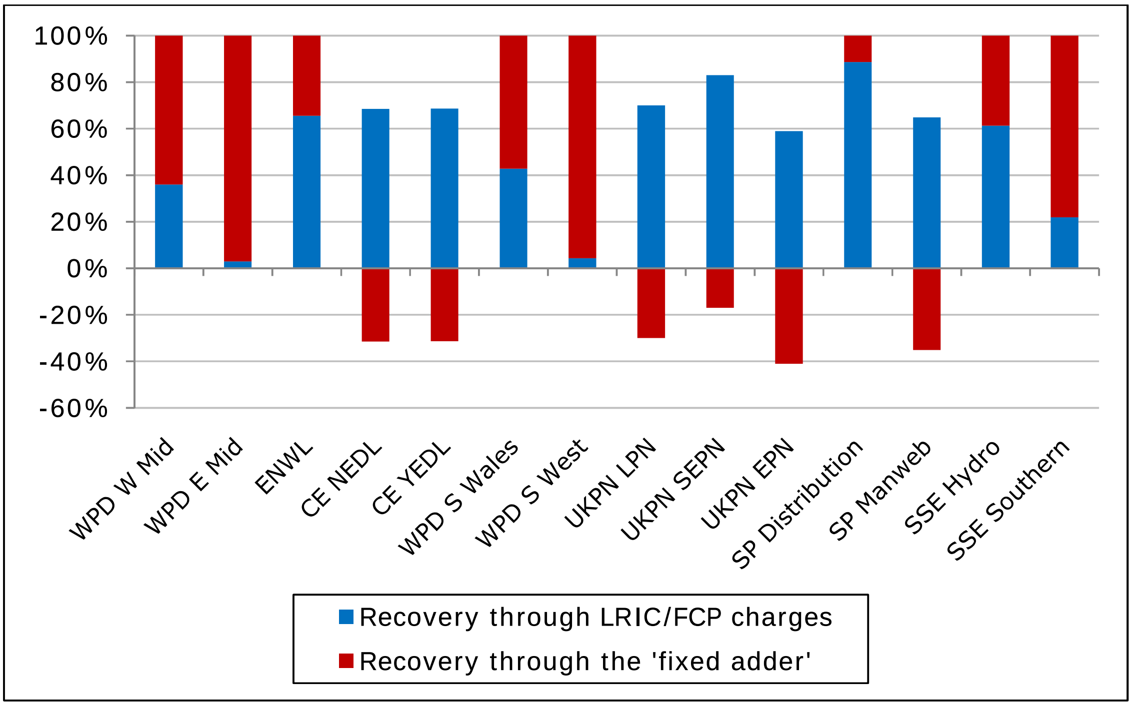
4.30. The fixed adder results in a scaling mechanism that is uniform and non-locational. That is, every generation customer receives the same £/kVA amount regardless of where they are located.

4.31. The fixed adder is calculated as follows:

$$\text{Fixed adder (£/kVA)} = \frac{[\text{DG revenue target (£)}] - [\text{total recovery from LRIC/FCP (£)}]}{[\text{EDCM generation capacity (kVA)}]}$$

4.32. Figure 4.2 shows the charge components of the generation revenue target and their respective percentage in the recovery of the revenue target. Negative red bars imply a negative fixed adder.

Figure 4.2 Recovery of the generation revenue target by percentage of charge component



Source: EDCM models in EDCM submission to Ofgem, April 2011

Our thoughts

4.33. We note that this method of scaling applied to generation charges is different from the method of scaling applied to demand charges. In the case of demand, 20 per cent of the residual is allocated on the same basis as in generation (ie a fixed adder based on capacity). The other 80 per cent, however, is allocated based on the values of assets deemed to be used by the customer, rather than based purely on capacity.

4.34. We think that the difference in scaling methods between demand and generation may be explained by the different way in which they drive network costs on a demand dominated network. If the networks are mostly demand dominated, then demand drives network capacity and the costs of most assets. Considering the specific assets used by the customer when allocating the proportion of the residual that is deemed to be asset related can be understood as an attempt to ensure a cost-reflective charge. On the other hand, generators, for the most part, use network assets that were sized for demand. It would be less intuitive to allocate generation charges based on the specific assets they use beyond their sole use assets. Allocating the residual equally per unit of export capacity seems reasonable. We welcome views on the approach to generation scaling and whether the difference to the demand scaling approach is sensible.

4.35. We note that a uniform, non-locational, fixed adder preserves the absolute difference between the LRIC/FCP locational signals (in £/kW). We indicated previously that we view this as a positive attribute of a scaling method. The undistorted LRIC/FCP locational signal provides an incentive to locate and generate where there is substantial headroom to accommodate additional generation capacity without the need for network reinforcement.

Issue 10: application of generation credits to units exported during super-red

The proposals

4.36. The EDCM proposals include a payment of credits to non-intermittent generators. The credit aims to reflect cost savings from deferred reinforcement works due to the local generation. Credit rates are calculated by the LRIC/FCP models.

4.37. The amount of credit payment to a generator depends on two factors: units exported during the super-red time band (kWh) and the credit rate per unit of output (£/kWh). Total credit payments to a generator are given by the equation below

$$\text{Generation credits (£/year)} = \left[\begin{array}{c}\text{export during}\\ \text{super-red (kWh)}\end{array}\right] * \left[\frac{\text{LRIC/FCP credit rate (£/kVA)}}{\text{number of super-red hours}}\right]$$

4.38. The proposals confine generation credits to units exported during the super-red time period – a relatively narrow, DNO specific, time band when the network is most highly loaded. This is a change from the DNOs’ position in previous consultations where a uniform credit rate applied to all units exported, regardless of when they were exported.

4.39. Their justification for this proposal is that the benefit to the network of generation flows is mainly in offsetting demand (load) flows when the network is highly loaded. For this reason only units exported during the super-red time band, which is when the network is highly loaded, qualify for the credit. The submission also points out that applying generation credits to units exported during the super-red time band is consistent with the way these credits were calculated—by assessing the contribution of generation flows during the ‘maximum demand scenario’ which aims to replicate maximum loading conditions.

Comparison of credits when applied to all exported units versus units exported during the super-red time band

4.40. The restriction of credits to units exported during the super-red time band does not imply that credit payments to generation will decrease relative to a situation where credits are paid to all units exported. This is because the credit rate per qualifying unit (kWh) would be higher. As the equation below shows, the lower the number of hours where export credit applies, the higher the credit rate:

$$\text{Generation credit rate (£/kWh)} = \frac{[\text{LRIC/FCP credit rate (£/kVA)}]}{\begin{bmatrix}\text{number of hours per year} \\ \text{where export credit applies}\end{bmatrix}}$$

4.41. We compared total generation credits paid in the EDCM models from the DNOs’ December consultation (where generation credit were paid for all year production) versus the amount in the EDCM models from the April submission (where credits are paid only to super-red production). We found that in 10 of the 14 distribution areas the total amount of generation credit increases when credit applies to super-red production only. Overall, total generation credits across all EDCM generation are estimated to be 26 per cent higher when credits apply to super-red production only than when credits applies to all annual production. This reflects that, for the most part, the volume of electricity exported during the super-red times.

4.42. Table 4.4 shows the super-red time band for each DNO, the number of annual hours covered by the time band and the ratio between generation credit rates if credits were paid for export in super-red hours only and if credits were paid for all annual export. The implied ratio is simply the number of annual hours (8,760) divided by the number of super-red hours, as implied by the formula above.

4.43. In an area where the super-red time band is as narrowly defined as in WPD S West, generation credit rates would be almost 60 times as high when paid to units exported during the super-red time band only than when paid to all exported units.

Table 4.4 Super-red time bands and the effect on the credit rate of applying credit to super-red export

DNO	Super-red time band[1]	Annual hours in super-red	Implied generation credit ratio
WPD W Mid	Monday to Friday November - February 16:00-19:00	261	33.6
WPD E Mid	Monday to Friday November - February 16:00-19:00	261	33.6
ENWL	Monday to Friday November - February 16:30-18:30	172	50.9
CE NEDL	Monday to Friday November - February 16:00-19:30	298	29.4
CE YEDL	Monday to Friday November - February 16:00-19:30	298	29.4
WPD S Wales	Monday to Friday November - February 17:00-19:30[2]	188	46.7
WPD S West	Monday to Friday November - February 17:00-19:00[2]	150	58.4
UKPN LPN	Monday to Friday November - February 16:00-19:00 June-August 11:00-14:00	459	19.1
UKPN SEPN	Monday to Friday November - February 16:00-19:00	261	33.6
UKPN EPN	Monday to Friday November - February 16:00-19:00	261	33.6
SP Distribution	Monday to Friday November - February 16:30-19:30	261	33.6
SP Manweb	Monday to Friday November - February 16:30-19:30	261	33.6
SSE Hydro	Monday to Friday October-March 12:30-14:30 October-March 16:30-21:00	845	10.4
SSE Southern	Monday to Friday November-February 16:30-19:00	218	40.3
Average		**299**	**34.7**

[1] Times are defined in reference to UK clock time
[2] Excluding Christmas and New Year periods
Source: EDCM submission, Appendix 4 and Ofgem analysis

Our thoughts

4.44. Credits to generators are given for their potential to defer reinforcement works and reduce overall network costs. To understand whether credits should apply to all year production or to production during the super-red time band it is useful to understand how generation could defer reinforcement.

4.45. Engineering Recommendation (ER) P2/6 is the current distribution network planning standard. The DNOs have a licence obligation to plan and develop their systems in accordance with ER P2/6. ER P2/6 specifies that, to demonstrate compliance, DNOs can assume a certain proportion of a generation installed capacity[29] (in kW) to contribute to security of supply. This proportion is given either by a generic "F factor", which is a statistical estimate of the availability of the generation capacity for the time required to repair a network outage, or by estimates of site specific F factors. In short, DG capacity on the network can be used to demonstrate compliance with ER P2/6 and in that way defer reinforcements that would otherwise be required.

4.46. This would suggest that generation credit should be paid against generation installed capacity, or maximum export capacity, scaled down by its F factor. Instead, the EDCM, as does the CDCM, applies generation credits to the production (kWh) of the generator.

4.47. The DNOs argued previously, in the context of the CDCM, that credits applied to units produced are less vulnerable to data errors or fraud and may better represent the actual contribution that individual generators make to security of supply than the use of a generic F factor. Moreover, providing credits to units produced has better potential to influence generation operation and consequently its availability for security of supply.

4.48. We accept the DNOs' arguments for applying credits to units produced rather than using the generator's capacity together with a generic F factor. We think that it may be inappropriate to use generic F factors without taking account of the forecast operating plans of the generator. Applying capacity-based payments based on generic F factors would reward rarely used generators (eg stand-by generators) as much as regularly operating generators, even though the latter provide more benefits to the network.

4.49. If credits are applied for units produced, there is still the question of whether it would be more cost-reflective to apply a single rate for all annual production, as the DNOs proposed in a previous consultation, or a higher credit rate for units produced during the super-red time band (ie system peak), per the DNOs' proposal in their formal EDCM submission.

4.50. We think there are arguments for either approach. On the one hand, a single credit rate for all units is appropriate if a generator's installed capacity and F factor, rather than its production, is taken into account for system security.

[29] ER P2/6 refers to "declared net capacity" defined as "[t]he declared gross capability of a Distributed Generation (DG) plant, measured in MW, less the normal total parasitic power consumption attributable to that plant."

4.51. On the other hand, generation during system peak may be taken into account to reduce maximum demand data in the demand group under consideration. This may be the case if there is enough diversity across generation so that a certain amount of generation can be reliably assumed to offset demand. If generation export is taken into account to reduce maximum demand data then applying a higher credit rate during times of maximum demand would be appropriate.

4.52. On balance, we think that the proposal to apply generation credits to units exported during the super-red time band is appropriate. We note also that this would be consistent with the CDCM, where generation credit rate for non-intermittent generation is higher during the “red” time band, when the system as a whole has a higher probability of peaking. Applying a higher credit for generation during system peak will provide an appropriate signal to generate when the system is most highly loaded. We would welcome respondents view on the matter.

Issue 11: no credit for intermittent generation

The proposals

4.53. Under the EDCM proposals, intermittent generation[30] does not receive generation credits.

4.54. This proposal reflects the view that “intermittent generators do not help offset the need for network reinforcement” (EDCM submission, paragraph 267 (e)).

4.55. The root of the decision not to apply generation credits in the tariff of intermittent generation is in a decision that was made for the purpose of the power flow analysis of the LRIC and FCP models. The decision is stated both in the LRIC guidance (Appendix 2(b), Paragraph 5.32) and the FCP guidance (Appendix 2(a), Paragraph 5.36):

> *The contribution of distributed generation to security of supply is dealt with in ER P2/6 through the application of F factors. Each distributed generator is assigned an F factor and this represents the percentage of the generator’s declared net capacity that can be considered when assessing network security. ER P2/6 also uses the term ‘Persistence’ to reduce the F factor for intermittent generation, as the time period (in hours) for which its contribution to security is being assessed increases. Table 2-4 of ER P2/6 recommends values of ‘Persistence’; these values are dependent on the demand class being assessed. The value of ‘Persistence’ to be used for intermittent generation will be as stated in Table 2-4 of ER P2/6 for ‘Other outage’, using the maximum GSP (or GSP groups’) demand instead of the demand class of the demand group.*

[30] Intermittent generation is a “[g]eneration plant where the energy source for the prime mover can not be made available on demand” (Engineering Recommendation P2/6).

4.56. The persistence level that corresponds to ‘other outage’ and the ‘GSP group’ is 90 days, and its corresponding F factor for the intermittent generation technologies in ER P2/6 is zero. In short, intermittent generation is not taken into consideration in respect of system security in the power flow analysis of the LRIC and FCP models. As we discuss below, this is not necessarily the case in network planning analysis.

4.57. Table 4.5 shows the share of intermittent DG in each DNO area.

Table 4.5 Number and share of intermittent generation in each DNO area

DNO	Number of EDCM generators	Number (percentage) of generators with NSF=0
WPD W Mid	15	6 (40.0%)
WPD E Mid	33	17 (51.5%)
ENWL	33	25 (75.8%)
CE NEDL	14	3 (21.4%)
CE YEDL	28	8 (28.6%)
WPD S Wales	36	11 (30.6%)
WPD S West	32	15 (46.9%)
UKPN LPN	7	1 (14.3%)
UKPN SEPN	16	7 (43.8%)
UKPN EPN	49	31 (63.3%)
SP Distribution	41	24 (58.5%)
SP Manweb	52	26 (50.0%)
SSE Hydro	136	71 (52.2%)
SSE Southern	31	1 (3.2%)

Source: EDCM models in EDCM submission to Ofgem, April 2011

4.58. DNOs routinely use power flow tools to analyse their network and identify forthcoming reinforcement requirements. As the DNOs say in their submission “The aim of using power flow analysis for pricing purposes is to replicate the reinforcement assessment process and determine the costs of future network reinforcements in order to generate cost-reflective incremental charges” (EDCM submission, Appendices 2(a) and 2(b), paragraph 2.3).

4.59. However, while the power flow analysis in LRIC/FCP is a stylised attempt to mimic planning procedures to the extent reasonable for charging purposes, it is not an exact replication of the power flow analysis used for network planning.

4.60. Unlike actual planning analysis, the power flow analysis in LRIC/FCP is applied within the constraints of a single set of power flow data. Consequently, certain simplifying assumptions needed to be made, one of which is that a single F factor be used rather than different F factors depending on the specific planning scenario considered. The DNOs considered that the most reasonable assumption given this constraint is that intermittent generation would not be considered for planning purposes. We think that this assumption is plausible <u>for the purpose of the power flow</u>.

Our thoughts

4.61. Intermittent generation cannot be relied upon for system security to the same extent as non-intermittent generation. When the generation is needed to provide network support, for example during unplanned outage situations, it may not be available for the duration of time required to complete the repair work.

4.62. The difference in the contribution to system security between intermittent and non-intermittent generation can be seen in ER P2/6, where the F factors, which represent the percentage of the generator's capacity that can be considered to contribute to system security, are substantially lower for intermittent generation than for non-intermittent generation.

4.63. Nonetheless, ER P2/6 indicates that in certain situations, depending on the outage event considered and the demand group, a proportion of the capacity of intermittent generation could be taken into account for system security. In other words, in many situations the recommended F factor is positive.

4.64. Whether the DNO will in fact rely on the generator's capacity would typically depend on circumstances. One general rule is that the less diversity there is, the less likely the DNO is to rely on the generation for network planning. DNOs are more likely to consider the recommended F factor, or a site-specific F factor, where there is sufficient diversity across generation.

4.65. Consistent with assumptions elsewhere in the EDCM, at the voltage level of connection there is little diversity and on network levels above connection, there is more significant diversity. We think that it would be appropriate to credit intermittent generation in respect of reinforcements deferred on network levels above their level of connection, where their collective diversified capacity may be taken into account to offset maximum demand data.

4.66. We note that the generation credit rate could be split into 'local' and 'remote' components in the same way the LRIC/FCP charge rate is broken down for demand customers.[31] The local credit represents benefits (ie deferred reinforcements) at the voltage of connection while the remote component represents benefits above the voltage of connection.

4.67. We think this split may allow a more cost-reflective application of credits to intermittent generation. Above the level of connection, it would be more consistent and plausible to assume that intermittent generation does provide real security of supply benefits. Given that the remote component represents benefits above the level of connection, it would be sensible to apply this credit to intermittent generation.

[31] In the case of FCP the 'remote' component is the applicable 'parent' plus 'grandparent' FCP charges.

4.68. There may be an argument that credits to intermittent generation should apply to all units exported regardless of when they were exported, unlike credits to non-intermittent generation that are applied to export during the super-red time band only.

4.69. This might be appropriate because intermittent generation have little control over the timing of their production and thus would not be able to respond to a targeted cost signal. We welcome views on whether this would be appropriate and cost-reflective.

4.70. Subject to responses to this consultation, we would consider making it a condition of our approval to allow some credit to intermittent generation if we deem such credits to be cost-reflective.

Issue 12: import charges for generation-dominated mixed import-export sites

The proposals

4.71. Sites with both import and export meter registrations are subject to both demand (import) and generation (export) tariffs under the EDCM.

4.72. In determining capacity charges for the import tariff of a mixed site, each mixed site is classified as either “generation-dominated” or “demand-dominated”. The classification is based on whether the “operating mode [in the site] is that of a demand customer or a generation customer (determined by examination of the Connectee's Maximum Import Capacity and Maximum Export Capacity or kWh consumptions as appropriate)” (EDCM submission, Appendix 2(b), paragraph 5.7). Essentially, a site is treated as “demand-dominated” if the maximum import capacity is greater than the maximum export capacity and vice versa.

4.73. If the site is demand-dominated, capacity charges for the import tariff will be determined in the same way as for a regular demand customer.

4.74. If the site is generation-dominated, capacity charges for the import tariff will be determined using network use factors (NUFs) set equal to the respective collar of each network level’s NUFs (as described in Annex 6 of the submission). The submission does not explain this decision.

4.75. In discussions through the development of the EDCM, the argument for not using the NUFs as obtained through the power flow analysis was that assets supplying a generation-dominated site had been sized based on generation capacity rather than on the lower capacity requirement of the demand function.

4.76. NUFs are used as the allocation driver of direct operating costs, network rates and 80 per cent of the residual. All these elements feed into the capacity charge rate of demand tariffs. Issue 4 and Issue 5 discuss in detail how NUFs are calculated and used in the EDCM.

4.77. The implication of the decision to set the NUFs of the import tariff in a generation-dominated mixed site to the respective collars is that capacity charge rate for the import tariff would be lower.

Our thoughts

4.78. The decision to set NUFs to their respective collars for demand charges in mixed generation-dominated sites seems somewhat arbitrary. We would like to see an explanation for this decision in the DNOs' response to this consultation.

4.79. A less arbitrary principle may be the following. A NUF of zero would be used at the level of connection. This is based on the argument that assets at the voltage of connection were largely sized for the maximum export capacity of the generation. Above the level of connection, the actual NUFs would be used. This is based on the argument that above the level of connection the assets would typically be shared by more customers—typically demands customers—and the network capacity associated with the site is more likely to be driven by its import capacity than its export requirement.

4.80. More significantly, it is not immediately obvious why the NUFs of a small demand customer sited next to a large generator (but not part of the same site) should not be subject to the same treatment as the NUFs of the import tariff in a generation-dominated mixed site. Such demand customer also uses assets that were sized to the generation requirement of the mixed site.

4.81. It would be desirable if the NUFs reflected the fact that the demand user uses just a very small proportion of assets that were sized to the generation capacity. That would remove the need to set NUFs to some default level in generation-dominated mixed sites. The calculation of NUFs does not take into account generation customers - each asset is fully apportioned only between the demand customers that use the asset. While this is sensible for assets that are sized for the maximum demand of load customers, it may not be appropriate for assets that were sized for the maximum demand of generation customers. It may be appropriate to classify generation-dominated assets and treat these assets differently in the power flow analysis used for the derivation of NUFs. We ask for stakeholders' views on the issue.

5. Charging proposals for licensed distribution network operators (LDNOs)

Chapter Summary

In this chapter, we summarise the EDCM proposals for charging of embedded networks, highlight key issues, and set out our initial thinking.

Question 5.1: Do you agree when calculating LDNO charges that DNO costs upstream and downstream of the point of connection should be considered?
Question 5.2: Do you think that DNOs should provide LDNOs with a discount on all non-asset based charges?
Question 5.3: Do you think that varying LDNO discounts only with the point of connection will better achieve a balance between reflecting upstream and downstream costs?
Question 5.4: Do you agree that it may be appropriate in some circumstances for the DNO to pay LDNOs use of system credits?

Overview of the methodology

Background

5.1. Charges to LDNOs that qualify as EDCM[32] customers will be calculated in accordance with the EDCM methodology. EDCM charges to the LDNO will be calculated on a portfolio basis. This means that the LDNO will receive a charge for use of the DNO's distribution system in respect of each end customer that is connected to its (the LDNO's) network.

5.2. It is important to note that whilst the EDCM is the basis for calculating charges for LDNOs that are connected to the EHV network of a DNO, end customers who are in turn connected to an LDNO network will for the most part be connected at a lower voltage level (either HV or LV). The method of calculating LDNO EDCM charges will depend upon the point of connection of the end customer.

5.3. Where an LDNO end customer qualifies as an EDCM customer, the LDNO charge is location specific, based on the EDCM methodology for calculating charges to other customers. However, where the customer qualifies as a CDCM customer,[33] the charge to the LDNO will be a discount from the DNO CDCM charge to an equivalent customer.

[32] "EHV designated properties" as set out in licence condition 50A.11
[33] "CDCM designated property" as set out in SLC 50A.10

Site specific charges for ECDM end customers

5.4. These charges are based on the EDCM methodology that is used by the DNOs to calculate charges to EDCM end customers. As set out in the EDCM submission and earlier in this consultation these charges consist broadly of the following components:

(i) LRIC/FCP charge component – related to future reinforcements of shared use assets used by the customer

(ii) Indirect cost charge – to recover a contribution towards indirect costs allocated to EDCM customers

(iii) Direct cost charge – to recover a contribution towards direct operating costs allocated to EDCM customers

(iv) Network rates charge – related to the DNO's network rates

(v) Exit charge – related to the DNO's transmission exit charge

(vi) Scaling charge – adjustment to charges to ensure that the revenue target allocated to EDCM customers is fully recovered.

5.5. Locational charges for EDCM end customers are calculated to the boundary point between the DNO and LDNO networks. So that charges can be calculated to the boundary, the methodology requires LDNOs to provide "boundary equivalent" data for each EDCM customer connected to their networks. This data will include, amongst other things, the required network capacity (at the DNO/LDNO boundary) of each customer. We summarise the proposed LDNO charges for EDCM customers in the table below. The table distinguishes between charges for demand and generation end customers as they are calculated slightly differently.

Table 5.1 LNDO EDCM Charges for EDCM end users

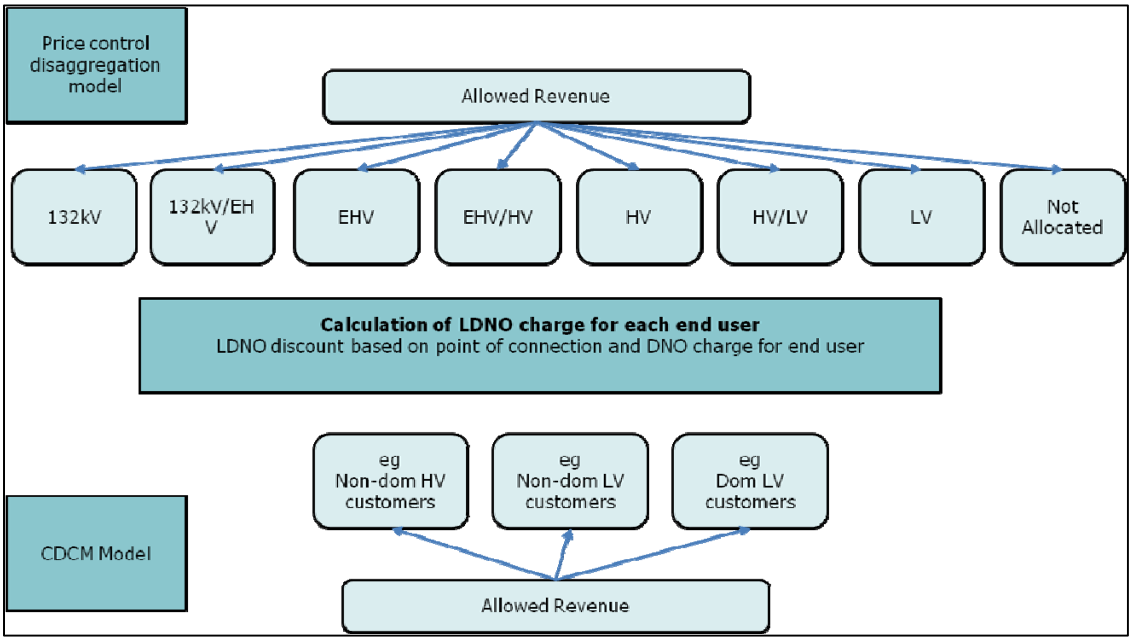
Charge component	Description	LDNO charge for EDCM Demand end users	LDNO charge for EDCM Generation end users
FCP/LRIC charge	Charge based on future cost of reinforcing shared assets	LDNO pays charges only for assets provided by the DNO	LDNO pays charges only for assets provided by the DNO
Indirect costs charge	Charge to recover a contribution to DNO indirect costs allocated to EDCM customers	Charge is a multiple of the required network capacity LDNO receives a discount of 50% compared to the charge for end user	No indirect costs charge is applied to generation customers
Direct costs and network rates	Charge for DNO direct costs and network rates allocated to both shared and sole use assets	LDNO pays charges only for assets provided by the DNO	These charges apply only to sole use assets attributable to the generation
Scaling charge	Adjustment to ensure that total charges equal revenue allocated to EDCM customers	20% of charge is a multiple of network capacity 80% is based on shared use assets used LDNO pays charges only for assets provided by the DNO	Charge is a multiple of network capacity
Exit charge	Charge related to the DNO's transmission exit charges	Charge is a multiple of the required network capacity at system peak	Not applicable

Discount charges for CDCM end customers

5.6. The discount methodology is an extension of the methodology used to calculate LDNO discounts (and charges) used in the CDCM. Where the LDNO end customers would qualify for CDCM tariffs the LDNO charges will be calculated as a discount from CDCM charges to equivalent customers. This discount is intended to reflect the assets provided by the DNO and LDNO, respectively, in providing distribution services to the customer. As currently proposed the discount varies with both the point of connection between the DNO and the LDNO and with the assets provided by the DNO upstream of this point.

5.7. The discount is calculated using a “price control disaggregation” model, which allocates price control revenue to network tiers (the “extended method M”). This allocation results in an estimate of the proportion of allowed revenues that is accounted for by each tier. These proportions are the basis of the LDNO discount. LDNOs receive a discount from the end user charges for each network level not provided by the DNO. We provide an overview of the discount methodology in Figure 5.1 below.

Figure 5.1 Overview of the CDCM LDNO charges



5.8. Under the CDCM, the discount methodology (“method M”) is used to calculate charges to LDNO networks connected to DNOs at the HV circuits, HV/LV transformation or LV circuits. The EDCM proposals are to extend this methodology to calculate discounts for LDNO networks connected to a DNO’s network at EHV/11kV transformation or higher voltages.

5.9. One difference with the CDCM method is that the LDNO discount depends on both the LDNO point of connection with the DNO and the assets provided by the DNO upstream of this point. For the CDCM the discount only varies with the LDNO point of connection. This means that whilst an HV, HV/LV or LV connected LDNO will receive the same discount regardless of the assets provided upstream by the DNO this will not be the case for LDNOs connected at higher voltages.

Our thoughts

5.10. We are broadly comfortable with the proposals as they are set out in the submission. We note that given that LDNOs are companies that compete with DNOs for the adoption of network extensions, DNOs should have taken appropriate measure to ensure that their charges comply with the Competition Act 1998 and EC competition law. We would further note that it is for the DNOs to ensure such compliance and that the processes and legal tests in relation to the approval of the EDCM methodology are separate and distinct from those that would be applied by the Authority in the course of investigations under the Competition Act 1998.

5.11. During the development of the EDCM, LDNO charging arrangements were discussed with Ofgem and LDNOs in a number of forums. During these discussions a number of issues were raised. We discuss the key issues and outline our thoughts on them below.

Issue 13: CDCM/EDCM boundary

5.12. According to SLCs 50A.10 and 50A.11, the distinction between a CDCM designated property and an EDCM designated property is based on its point of connection as identified by the location of the metering point for that customer. It will not always be possible for an LDNO to identify the point of connection by the metering point, as there will not always be a meter in place to measure flows between the DNO and the LDNO.[34]

5.13. Prior to the submission of the EDCM, the DNOs submitted to us a proposal to change the definitions in 50A.10 and 50A.11 so that for LDNOs the point of connection between a DNO and LDNO is the ownership boundary. We have consulted

[34] Following Ofgem's decision on boundary metering and the adoption of portfolio billing, whereby LDNOs are billed using metering data from end customers instead of measured flows across the boundary, it is not always the case that a DNO will choose to install a meter at the point of connection. Ofgem's boundary metering decision can be found on our website at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=138&refer=Networks/ElecDist/Policy/IDNOs.

on our proposal to change the licence accordingly.[35] We do not seek further views on this issue as part of this consultation.

Issue 14: components of location specific charge paid by the LDNO

5.14. Table 5.1 above provides an overview of the calculation of the location specific charges to LDNOs for EDCM end customers connected to their networks. Broadly, the components of the LDNO charge are calculated with reference either to the assets used by the LDNO end customer on the DNO's network, or to the "boundary equivalent" capacity declared by the LDNO for the customer.

5.15. Where the charge components are based on the assets used, the LDNO will only be liable in relation to assets on the DNO network. This means that, the LDNO will not pay any asset based charges in relation to the assets it provides. Where the charge components are based on boundary equivalent network capacity the LDNO will be liable for the full charge, except in the case of the indirect costs charge where the LDNO will receive a 50 per cent discount. The 50 per cent discount is intended to reflect the fact that LDNOs will have to cover indirect costs of their own and ultimately could potentially displace some of the DNO indirect costs.

5.16. Our initial thoughts are that it is appropriate that the LDNO does not pay any charges that are associated with the assets that it provides. We also think that it is appropriate that LDNOs receive a discount from the indirect costs charge as the charge to the LDNO should consider an appropriate, cost-reflective, allocation of <u>all</u> DNO costs to network activities both upstream and downstream of the point of connection.

5.17. We think that similar logic could be applied to capacity-based charges other than the indirect costs charge, notably scaling of both demand and generation charges. We think that a similar argument could apply to these costs in that they include costs that will be incurred by an LDNO and could potentially be displaced by LDNOs and that some of these costs could reasonably be attributed to the downstream network activity.

5.18. We seek views on whether a discount should be applied to LDNO scaling charges. Our initial view is to make it a condition of our approval of the EDCM that a discount is applied to this element of the LDNO charge.

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[35] The consultation letter can be found on our website at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=666&refer=Networks/ElecDist/Policy/DistChrgs .

Issue 15: number of discount tariffs (connection types) applicable to LDNOs

5.19. As noted above, the DNOs' proposal is for the LDNO discounts on CDCM charges to vary with the point on connection and also with the assets provided by the DNO above the point of connection. To cover all possible connection configurations the DNOs propose that 15 new tariffs be introduced for LDNOs that are classified as EDCM customers in respect of their CDCM end customers.

5.20. For example, consider an LDNO connected to a 33kV circuit and therefore subject to the EDCM. The discount is applied to its LV end customers will vary depending on whether the DNO provides the 132kV circuits and 132/33kV transformation or whether the DNO provides only the 132/33kV transformation but does not provide any 132kV circuits as the transformer is co-located with a grid supply point.

5.21. We have some concerns about this proposal. We do not think that it is consistent to vary the discount with the assets provided by the DNO because the charge to the end customer (the “all the way charge”) is the same for CDCM customers regardless of the assets provided by the DNO. As we note above, we think that cost reflectivity for LDNO charges must include consideration of cost both upstream and downstream of the point of connection. The current proposal will lead to variation in LDNO charges with assets provided by a DNO but this variation will be irrespective of the assets provided by an LDNO. The effect of the proposal is to improve the upstream cost-reflectively of the charges at the expense of downstream cost reflectivity. We think that an LDNO discount that only varies with the point of connection would achieve a more appropriate balance between upstream and downstream network costs. We also think the proposal creates a practical issue in that varying the discount with assets provided and point of connection creates the need for a greater number of LDNO tariffs than would be necessary if the discount only varied with point of connection. Potentially the additional tariffs will each need to be assigned a line loss factor class (LLFCs) for billing purposes. Each DNO only has a limited number of LLFCs available and with some DNOs already approaching their limit the need for additional LLFCs could make it difficult for them to bill the EDCM tariffs. This issue is linked to our discussion of the wider issue of customer classes that we discuss in Issue 7.

5.22. We seek views on whether the LDNO discount should vary with the assets provided by the DNO as well as the point of connection. Our initial view is to make it a condition of our approval of the EDCM that the methodology is revised so that LDNO discounts only vary with the point of connection of the LDNO.

Issue 16: capping discount percentages to 100 per cent

5.23. As outlined in Figure 5.1 there is an element of the DNO’s price control revenue that is not eligible for inclusion in the LDNO discount. This is the element relating to incentive revenues. Incentive revenues are not included in the discount because LDNOs are not subject to the same incentive regime as DNOs and these revenues are not necessarily related to the cost of running the DNO network.

5.24. Where DNO incentive revenues are positive this will have the effect of reducing the portion of the LDNO end customer charges that are available to be discounted. Where these revenues are negative, the effect will be to increase the portion of charge available for discounting. The submission proposes to cap the portion of charge available for discounting at 100 per cent of the charge. Without the cap at 100 per cent, where an LDNO connects to the higher network tiers, and a DNO's incentive revenues are strongly negative, the methodology could produce LDNO discounts of greater that 100 per cent which would imply a payment of credit from the DNO to the LDNO for use of system.

5.25. We think that in circumstances where without capping the discounts could be greater than 100 per cent it may be appropriate for DNOs to pay LDNOs some kind of credit, particularly where the implied discount is significantly in excess of 100 per cent. This is because the incentive revenues are not clearly related to the cost of running the DNO network and therefore the impact of capping may be that the DNOs total costs are not fully considered for the LDNO discount.

5.26. We seek views on whether the LDNO discount should be capped at 100 per cent. We do not propose to make the removal of the 100 per cent cap a condition of approval of the EDCM because we know of no circumstances currently where there is an LDNO network that would qualify for a discount of greater than 100 per cent. We also do not think that it is likely to be an issue in the near future because no DNO has strongly negative incentive revenue and because the LDNO network would have to be connected very high up the network (possibly directly to the GSP) to qualify. We think that this position should be reviewed and a solution should be sought under the open governance process at the earliest convenience.

Impact on customers

5.27. EHV connected LDNOs are currently charged using the same basis as all other EHV customers. The EDCM introduces LDNO specific charges for EHV connected LDNOs for the first time. The impact on LDNO charges is difficult to quantify, as it will depend on the site-specific EHV methodologies currently used by DNOs and on the characteristics of all end customers at each LDNO site. However, the charges should be more appropriate to the circumstances of LDNOs.

5.28. LDNOs will levy charges on end customers. These charges are intended to pass through the charges from DNOs to end customers and also to recover the costs of operating their networks. Charges by LDNOs are limited by their charging methodologies, and for domestic customers their licence, to be not greater than charges to equivalent customer by the host DNO.[36] There is the potential that

[36] The host DNO means the DNO in whose distribution services area the network is located.

changes to DNO charging methodologies may therefore lead to charge changes by LDNOs to end customers. However, as it is our understanding that there are no EDCM qualified customers currently connected to LDNO networks, there should be no changes to the charges of current LDNO end customers as their charges will be limited by the DNO CDCM tariffs.

6. Common issues

Chapter Summary

In this chapter, we highlight remaining key aspects of the EDCM that are common to demand and generation customers and set out our initial thinking. The issues are:

- charging for sole use assets
- charging arrangements for demand and generation side management agreements
- consideration of reactive power
- the method for capping branch recovery in the LRIC model

In addition we discuss volatility and our view of further work we expect the DNOs to deliver in order to help customers manage charge volatility.

Question 6.1: Do you think sole use assets should attract scaling 'costs' to the same extent as shared assets? Does the charging rate on sole use assets seem reasonable given the nature of these assets?
Question 6.2: Do you agree with our view that the arrangements for demand and generation side management agreements are appropriate? Do you think such agreements should be available to all customers?
Question 6.3: Do you agree with our assessment that an explicit reactive power charge is not appropriate?
Question 6.4: On the proposal for sense checking branch incremental costs in LRIC:

- Do you agree with our view that positive cost recovery (ie charges) and negative cost recovery (ie credits) should be considered separately?
- Do you consider that recovery from demand customers and recovery from generation customers should be considered separately?

Question 6.4: Do you think the EDCM should include a mechanism to mitigate the potential volatility from network use factors? We welcome views on measures to mitigate volatility and help customers manage volatility.

Issue 17: sole use asset charge

The proposals

6.2. Every customer's tariff will include a fixed charge. The fixed charge is essentially a sole use asset (SUA)[37] charge as it reflects costs associated with the customer's sole use assets. The EDCM proposals for sole use asset charges are outlined in paragraphs 156-160 of the submission.

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[37] The EDCM proposals define sole use assets as "assets in which only the consumption or output associated with a single customer can directly alter the power flow in the asset, taking into consideration all possible credible running arrangements". For a more information refer to the EDCM submission, paragraphs 116-125.

6.3. Under the DNOs’ proposals, sole use assets attract two types of costs: direct operating costs and network rates. The sole use asset charge is calculated as follows:

$$\text{SUA charge (£/year)} = \frac{\text{SUA (£)}}{\text{total asset value in the DNO's area (£)}} * \begin{bmatrix}\text{adjusted direct costs (£/year)} \\ \text{+ network rates (£/year)}\end{bmatrix}$$

SUA is the modern equivalent asset value (MEAV) of the customer’s sole use assets. The denominator, total asset value, is the MEAV of all assets in the DNO area, across all voltage levels, including both sole use and shared use assets. Network rates are the total expense on network rates paid by the DNO. Adjusted direct costs are the total direct operating costs of the DNO scaled down to reflect the lower operating cost intensity on higher voltage assets.

6.4. We note that under the proposals sole use assets do not attract any indirect costs or scaling charges.[38]

6.5. The reason that sole use assets do not attract indirect costs is that, under the proposals, indirect costs are allocated to customers based on their capacity and not based on their assets (in the case of demand the indirect cost charge is an explicit fixed adder per kVA and in the case of generation it is implicit within the fixed adder for scaling). Effectively this allocation rule relies on the assumption that capacity is the cost driver of indirect costs and whether this capacity requires long or short assets has an immaterial, or at least secondary, effect on indirect costs.

6.6. The reason that sole use assets do not attract scaling charges is less evident, especially in the case of demand customers.[39] For demand customers, 80 per cent of the residual (the difference between the revenue target and the recovery through pre-allocated costs) is allocated based on customers’ notional shared assets. This allocation rule relies on the assumption that the majority of the residual is driven by the ‘quantity’ of assets (measured in pounds) that the customer uses. This quantity is driven not by the customer’s capacity requirements, but also by the length of the assets that are used to supply it.

6.7. The justification for the different treatment between shared and sole use assets for demand charges is given in paragraphs 158-159 of the EDCM proposals report:

[38] We note that in the determination of the demand revenue target, sole use assets (of both CDCM and EDCM customers) are taken into account for the split of all identified costs, including indirect costs, and the residual allowed revenue (see Issue 1).

[39] Scaling charges for generation customers are applied as a fixed adder on capacity without regard to assets. Neither shared nor sole use assets attract scaling charges.

158. Unlike shared network assets, sole use assets do not attract a demand scaling charge. The decision to treat sole use assets differently was made taking into account the DNOs' expected propensity to replace these assets and the extent to which these assets might have been funded through customer contributions.

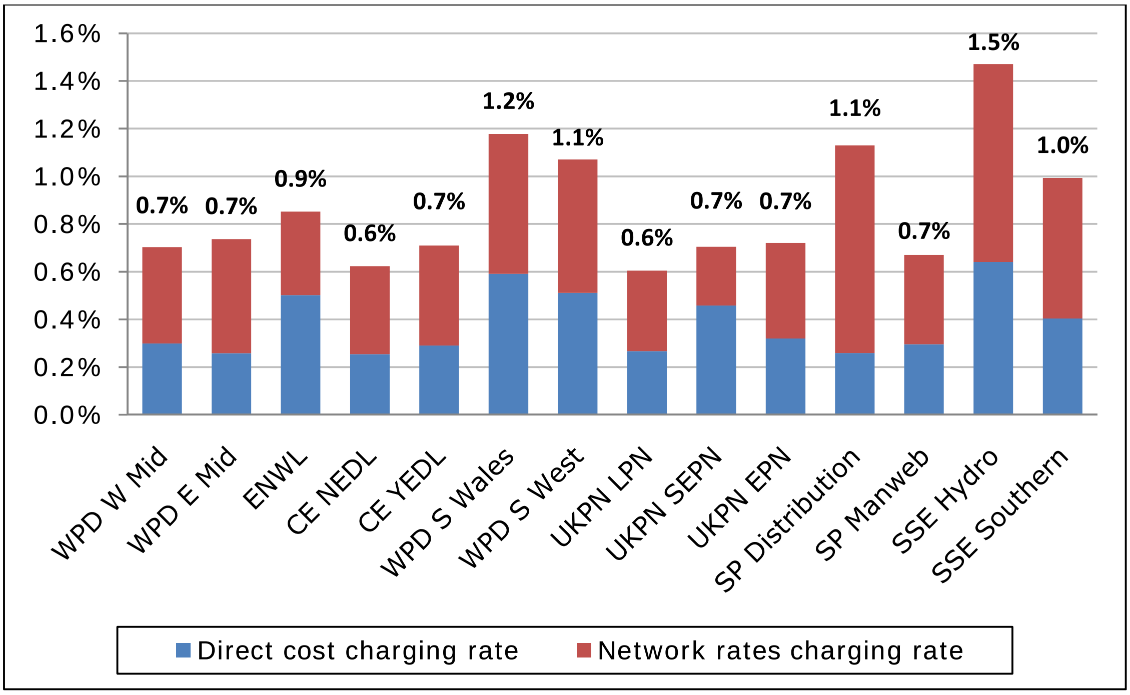
159. The assumption made is that sole use assets are fully contributed, and on the balance of probabilities these assets would not be replaced at the end of their 40- year accounting life, or these assets would no longer be sole use assets at the end of 40 years, or the customer would have terminated their connection in that time.

Our thoughts

6.8. Our concern with this proposal is that sole use assets do not attract any scaling charge. The rules for demand scaling suggest that 80 per cent of a typical residual is asset related. It is not clear why this share of the residual is deemed to be related to shared assets and not to sole use assets, although we think the justification provided in the proposals is a reasonable explanation for why sole use assets do not attract *as much* of the residual as shared assets.

6.9. Figure 6.1 demonstrates sole use asset charging rates across DNOs. A one per cent charging rate implies that each year the customer will pay a fixed charge equal to one per cent of the value (in MEAV) of it sole use assets.

Figure 6.1 Annual sole use asset charges as a percentage of the MEAV of sole use assets



Source: EDCM models in EDCM submission to Ofgem, April 2011

6.10. We welcome views on the way the proposed methodology calculates charges related to sole use assets. We would also welcome views on the resulting charging rates on sole use assets, bearing in mind that sole use assets largely correspond to contributed assets (ie assets paid for as part of connection fees). These assets entail little monetary obligation on the DNO other than to maintain and, with some probability, replace the assets in the long term.

6.11. Notwithstanding the above, we think the proposal aims to achieve a cost-reflective charging rate on sole use assets. We urge the DNOs to re-evaluate the case for not imposing any scaling charge to sole use assets of demand customers, however we feel reasonably comfortable to approve this aspect of the methodology and subject it to the scrutiny of open governance arrangements.

Issue 18: demand/generation side management

The proposals

6.12. The EDCM proposals for charging arrangements for customers subject to demand side management (DSM) agreements or generation side management (GSM) agreements are outlined in paragraphs 95-98 of the submission.

6.13. DSM/GSM agreements restrict the customer's capacity in certain situations. These situations may be at the discretion of the DNO or at pre-determined times. We term 'firm capacity' the capacity that is not constrained by the agreement (termed "chargeable capacity" in the report) and 'interruptible capacity' the capacity that may be constrained under the agreement.

6.14. According to the proposals, the LRIC/FCP charge of customers that operate subject to a DSM/GSM agreement will be scaled down by the proportion of the firm capacity to the maximum agreed capacity. This is shown in the equation below:

$$[\text{LRIC/FCP (£/kVA)}]_{\text{DSM/GSM}} = \left[\frac{\text{firm capacity}}{\text{maximum capacity}}\right] * [\text{LRIC/FCP (£/kVA)}]_{\text{raw}}$$

The procedure applies both to the 'local' and 'remote' LRIC/FCP components in the case of demand customers.

6.15. Put another way, customers subject to a DSM or GSM agreement will be charged like any other customer except that:

- for generation customers, the LRIC/FCP charge will apply only to the firm capacity and not to the interruptible capacity
- for demand customers, the local LRIC/FCP component will apply only to the firm capacity and not to the interruptible capacity. The remote LRIC/FCP component will apply to a proportion of their super-red kWh consumption equal to the share of firm capacity out of maximum agreed capacity.

6.16. This proposal is a change from the DNOs' December 2010 consultation, where the proposal was that the interruptible capacity will not attract any charge at all. Namely, in addition to not attracting the LRIC/FCP charge, it will not attract the fixed adder in the case of generation customers, and the direct operating costs, indirect costs, network rates and scaling charges in the case of demand customers.

6.17. The submission does not explain the move from the previous position, but states, "[s]uch agreements may remove the need for network reinforcement that might have been unavoidable otherwise" (EDCM submission, paragraph 95).

6.18. This offers the rationale for the current proposals: since it is the LRIC or FCP charge component that represents costs related to future reinforcements, remuneration for agreements that avoid network reinforcements should be constrained only to the application of these components to the capacity that is constrained by the agreement – the interruptible capacity.

Our thoughts

6.19. We agree that the interruptible capacity is not expected to contribute to future reinforcements and therefore should not attract a charge in respect of future reinforcements. That is, we agree that LRIC/FCP charges should not apply to interruptible capacity.

6.20. We think that the current proposal is an improvement over the proposal in the DNOs' December consultation. The current proposal provides a larger charge discount where the customer subject to the agreement is located in a congested area of the network. This is because the LRIC/FCP component would be higher the more congested the location is. We think this is an appropriate signal that is reflective of the value of the agreement in terms of avoided or deferred reinforcement costs.

6.21. Under the proposal in the DNOs' December consultation, the discount for these agreements bears little relation to the congestion of the assets used by the customer. A customer in a non-congested location (ie where assets have a lot of spare capacity) could have a larger incentive to enter such agreement than a customer in a congested location because the signal may be dominated by the avoided charges related to direct operating costs, network rates and scaling. However, from the DNO's perspective there is no great value in an agreement that restricts capacity in a non-congested area where there is enough spare capacity. Our view is that such signal would not be cost-reflective.

6.22. In addition, an implication of the December proposal is that a customer with an agreed capacity of, say 20MW and a customer with an agreed capacity of, say, 60MW of which 40MW is interruptible, will be charged the same DUoS charge. In our view, this is not cost-reflective.

6.23. The proposal is not clear on the terms available to customers of entering such agreements. In particular, whether any customer can enter a DSM/GSM agreement with the DNO, provided the customer agrees to have interruptible capacity subject to such terms as defined by the DNO, or whether the DNO can refuse to enter such agreements. Our view is that if charging arrangements under these agreements are cost-reflective they should be available to any customer. We urge the DNOs to clarify this issue in their charging methodology.

6.24. For the avoidance of doubt, our initial assessment is that the proposal for DSM/GSM arrangements is sensible and provides an appropriate signal.

Issue 19: reactive power charges

The proposals

6.25. The methodology does not include an explicit reactive power charge for either demand or generation (EDCM submission, paragraph 102).

6.26. This is a change from the DNOs' December 2010 consultation where there was an explicit reactive power charge for 'excess reactive power'. Excess reactive power refers to reactive units (kVArh) in excess of the amount that would contain the customer's power factor above 95 per cent.

6.27. The justification provided is that 'the method used to calculate the LRIC and FCP unit rate charges, applied to active units consumed during the super-red time band, take account of the effect on the network of the customer's power factor (using historical data). Therefore the active power unit rate includes an implicit charge for reactive flows' (EDCM submission, paragraph 103).

6.28. Reactive power flows contribute to the capacity (kVA) requirements of assets through the following equation:

$$kVA = \sqrt{kW^2 + kVAr^2}$$

where kVA (kilo volt ampere) is a unit of network capacity, kW (kilowatt) is a unit of active power flow and kVAr (kilo volt ampere reactive) is a unit of reactive power flow.

6.29. Distribution network costs are driven by capacity (kVA) which in turn is driven by active and reactive power. Both active and reactive power flows have a cost associated with them. Accordingly, a methodology that aims to reflect costs imposed on the network should include charges for both active and reactive power.

6.30. One way to charge for both active and reactive power is to set a cost-reflective capacity charging rate (£/kVA) and apply it to the capacity used by the customer. Most EDCM charges are applied as capacity-based charges.

6.31. However, when the charge is applied to active power (in kW or kWh), either a separate charge for reactive power should complement it, or the charge rate for active power (£/kW) should be uplifted to reflect the full cost of capacity.

6.32. In the EDCM, there is one instance where the charge is explicitly levied on active power. This is when demand customers are charged for their kWh consumption during the super-red time band. The DNOs argument above is an explanation for why a separate reactive power charge is not appropriate in this case – because the charge rate per kWh has already been uplifted to reflect reactive power flows at the location of the customer.

6.33. The charge rate for kWh in the super-red time band is based on the remote LRIC/FCP charge. The uplifting described in paragraph 82 of the submission is done by dividing the remote LRIC/FCP charge by the power factor[40] at the location of the customer. A customer with a lower power factor would have its remote LRIC/FCP rate uplifted by a higher proportion.

Our thoughts

6.34. We welcome views on the DNOs' explanation for the removal of an explicit reactive power charge. Our initial thought is that having an explicit reactive power charge together with the uplifting described above would amount to double charging of reactive power. We are therefore of the view that the current proposal is more appropriate than the proposal in the December 2010 consultation.

Issue 20: sense checking of branch incremental costs in LRIC

The proposal

6.35. The DNOs are proposing to amend the LRIC model to cap branch[41] charges that are considered excessive when compared to of the annuitised cost of the actual reinforcement cost of the branch. A description of their proposal can be found in EDCM submission, Appendix 2(b), paragraphs 8.3 to 8.9.

6.36. According to the submission, capping is done on a branch by branch basis in two steps:

- **Step 1:** Total recovered costs in respect of a particular branch are compared to the actual reinforcement cost of the branch (both costs are on an annuitised basis).
- **Step 2:** If recovered costs are greater than actual reinforcement costs, all incremental costs associated with this branch are scaled down proportionately to ensure exact recovery of the actual reinforcement costs of the branch.

6.37. The proposals calculate total recovered costs in respect of a branch as the total net recovery from demand and generation customers. That is, negative LRIC recovery (known as "credits") in respect of both demand and generation, resulting from deferring the branch reinforcement, are netted off positive recovery, resulting from bringing forward the branch reinforcement.

[40] Power factor (PF) is the ratio of real power to apparent power (PF=kW/kVA). The closer the power factor is to unity (ie 1) the less reactive power there is in the AC power system.
[41] The term "branch" is defined in Appendices 2(a) and 2(b) of the EDCM submission. In essence, a branch is a continuum of assets without a tee-off point along it, so that the active power flowing into one end equals the active power flowing out of the other end of the branch less any losses within the branch.

6.38. We note that the proposal is for the sense checking procedure to be integrated into the LRIC model. Cost recovery related to a branch represents the recovery within the LRIC model even though actual recovery may be different for various different reasons:

(i) negative branch recovery related to demand customers (obtained in situations where demand (load) power flow defers reinforcements) is not actually applied in final tariffs but is considered in the sense checking procedure

(ii) negative LRIC charges (see EDCM submission, paragraphs 92-94) are not applied in final tariffs but are considered in the sense checking procedure

(iii) the capacities used for the calculation of branch recovery are the capacities used in the power flow modelling and these capacities generally do not precisely equate to the capacities used in the pricing model

Our thoughts

6.39. During the development of the EDCM, we urged the DNOs to sense check their charges. Rather than applying an opaque sense checking mechanism, possibly on a case by case basis, the capping method developed is an integral part of the common LRIC methodology, which provides transparency and subjects the process to open governance.

6.40. We have two concerns related to the calculation of total recovered costs in respect of a branch (termed 'overall cost recovery' in the submission and hereafter).

6.41. First, we think that overall cost recovery should consider positive recovery and negative recovery separately. Essentially, we want to ensure that the total costs related to bringing forward the branch reinforcement do not exceed the branch reinforcement cost. Separately, we want to ensure that total credits related to deferring the branch reinforcement do not exceed the branch reinforcement cost.

6.42. By way of an example, if the branch reinforcement cost is £500,000 and LRIC calculates total recovery related to bringing forward the reinforcement of this branch to be £1m then this may be considered excessive regardless of the amount of credits paid in respect of the same branch. Similarly, the total benefits of deferring the reinforcement of the branch (ie credits) should not exceed the reinforcement cost of the branch.

6.43. Second, there may be an argument to consider overall cost recovery from demand customers and from generation customers separately. That is, in identifying "excessive" charging, the cost recovery in respect of a branch would be compared separately for demand and generation against the branch reinforcement costs.

6.44. The reason is that demand and generation power flows are not cumulative. Consequently, they do not have a cumulative effect on asset capacity which is the trigger of reinforcement. Rather, demand flows alone are cumulative and the costs recovered from demand customers should be compared to the costs they alone may trigger (ie demand-led reinforcement). Separately, generation flows alone are cumulative and their overall cost recovery should be compared to the cost they alone may trigger (ie generation-led reinforcement). We recognise that the demand-led and generation-led reinforcement is ultimately the same reinforcement, however, the cost impact of demand capacity and generation capacity is essentially independent from one another and we think there is an argument that they could be assessed independently.

6.45. We note that it could be argued that this approach should take into account the relative probabilities of demand-led and generation-led reinforcement.

6.46. We seek views from stakeholders on whether the sense checking procedure should examine positive recoveries and negative recoveries separately and on whether the procedure should assess demand and generation separately. We note that assessing positive and negative recoveries separately is expected to result in more instances of capping while assessing demand and generation separately is expected to result in less capping.

6.47. Subject to responses to this consultation, we will consider placing a condition to amend the method for sense checking. We also seek evidence from DNOs on the impact of these amendments on customer charges and the revenue target.

Issue 21: volatility

6.48. In our October 2008 decision document,[42] we noted that the new charging methodologies are likely to contain inherent year-on-year charging volatility. Suppliers, generators and large customers have all expressed concerns around potential charge volatility and indicated interest in developing mechanisms to mitigate potential volatility.

6.49. To address these concerns, we required DNOs to publish, on an annual basis, long term tariff scenarios that would help increase customer awareness of the potential range of future charges. DNOs were further required “to develop and bring forward proposals for longer term products that would offer generators and customers the choice of fixing their use of system charges in return for making a commitment to pay them, to help customers manage the risk of charging volatility” (October 2008 decision document, page 9). We indicated that DNOs are expected to follow up and address residual issues around volatility, transparency and predictability of charges through open governance arrangements.

[42] “Delivering the electricity distribution structure of charges project”, Ref: 135/08 1 October 2008, available at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=447&refer=Networks/ElecDist/Policy/DistChrgs

6.50. DNOs set up the Long Term Products Working Group ("Workstream C") to identify, assess and consider mitigating measures for the volatility under the CDCM and EDCM. It was agreed that the starting point in addressing volatility would be improving transparency and predictability of the charging model by providing additional information and ensuring DNOs use consistent assumptions in modelling volatility.

6.51. The DNOs submitted a report on EDCM volatility on 8 April 2011. The report provides an overview of the potential impact on charges when varying certain inputs, such as loading levels on network assets in the power flow analysis, allowed revenue, super-red consumption and network use factors.

6.52. In general, the analysis shows that charges for demand customers are sensitive to their consumption during the super-red time period. Increasing super-red consumption by 15 per cent led to an average increase of 28 per cent in charge. Unlike some of the other inputs, however, super-red consumption can be managed by the customer to an extent, and therefore also the volatility it causes. The analysis also shows that changes in power flows have a large potential impact, in particular on generation charges. The analysis did not present the impact on charges separately under LRIC and FCP.

6.53. The report makes a distinction between inputs that are a source of internal volatility – inputs which a customer can influence (eg super-red consumption), and inputs that are a source of external volatility – inputs which a customer cannot influence (eg allowed revenue).

6.54. We note that because of scaling all inputs are sources of external volatility. Super-red consumption is a source of external volatility because if some customer reduces its super-red consumption and consequently its charge, it will have an effect on the charge of all other customers, as the DNO still has to recover a typically unaltered revenue target from its EDCM customers.

6.55. Further details on the assumptions and findings of the volatility report can be found in Appendix 5 of the DNOs' EDCM submission.

6.56. The Long Term Products Working Group has agreed that DNOs will consider carrying out a more comprehensive analysis based on customer feedback following their EDCM submission. The group proposes to build on the current analysis by carrying out additional sensitivity analyses on EDCM inputs and exploring measures to mitigate year on year volatility. Ofgem has indicated that they expect DNOs to fully engage and seek customer feedback on the analysis in an open and inclusive manner.

6.57. We are considering placing a requirement on DNOs to deliver a package of measures to mitigate some of the inherent volatility within the EDCM and to allow customers the option to manage their charge volatility through access to a long term product with a more stable (but not necessarily fixed) charge. We will set such a requirement against an effective timescale. We encourage stakeholders to provide their view on this issue.

Volatility due to network use factors

6.58. The EDCM uses network use factors (NUFs) to set demand charges. NUFs are explained in Issues 4 and 5. While NUFs would be classified as a source of internal volatility, (a customer can reduce its NUFs by reducing its consumption at system maximum demand) NUFs also introduce external volatility. This is because a customer’s NUF may change as a result of other customers connecting or de-energising in its part of the network, or simply because a change in other customers consumption pattern.

6.59. NUFs are re-calculated and updated annually. The submission does not include a proposal to mitigate the potential year on year volatility of NUFs. We note, however, that the proposal to restrict NUF values by a cap and a collar mitigates the potential volatility to some extent.

6.60. We would like to use this opportunity to get feedback on applying a smoothing mechanism to customers’ NUFs. As an example, a smoothing mechanism can be a three-year rolling average, whereby the value of a NUF is equal to the average value of NUFs from the last three years. Under this mechanism, NUFs are still updated yearly, but the transition to the new value is slow rather than immediate.

6.61. We note that applying a rolling average to smooth the impact of NUFs’ volatility has both advantages and disadvantages. On the upside, applying a smoothing mechanism to NUFs would reduce their potential to exert charge volatility. On the downside, a customer’s ability to reduce its charge quickly would be limited (ie if a customer reduces its peak time consumption in a particular year, the full effect on its charge would only be realised after three years).

Comment to DNOs on the Excel charging spreadsheet

6.62. We think the presentation of the Excel model could be improved and we urge DNOs to progress this before incorporation into DCUSA. DNOs should ensure that the model is transparent in structure, worksheet names and table names. We appreciate that populated models will not be made public at this point in time; if they do become public (possibly on an anonymised basis) they should be as accessible as possible to users. A better model interface can minimise errors, facilitate future changes and facilitate analysis by DCUSA working groups.

6.63. We suggest, in particular, that tables should not have identical names (Table 4215 and Table 4216). “Miscellaneous” should not be used as a name for a worksheet or a table as it provides no indication of the content. The presentation in the “Miscellaneous” worksheet can be improved by re-locating Table 4401. Table 1112 includes an empty cell titled “Not used” which we think can be removed.

“Capacity based allocation thing for indirect costs” (Table 4277) should be renamed to something more appropriate.

6.64. We note that these are merely suggestions for what we consider good practice. We recognise that building a well constructed model during the development of the EDCM was difficult as changes and additions had to be made frequently, but now that the EDCM is complete, we would appreciate an effort to tidy up the Excel spreadsheet to facilitate future use.

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document. We would especially welcome responses to the specific questions, which we have set out at the beginning of each chapter heading. These are replicated below.

1.2. Responses should be received by 4 July 2011 and should be sent to:

- Ynon Gablinger
- Distribution Policy
- Ofgem, 9 Millbank, London SW1P 3GE
- 020 7901 7051
- distributionpolicy@ofgem.gov.uk

1.3. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.4. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

Chapter 2

Question 2.1: What are your views on the key issues with the methodology we have highlighted? Are there any other issues or concerns with the methodology as a whole that we should consider?
Question 2.2: Should we approve the methodology, do you agree with our proposal to implement it in full from 1 April 2012? If not, why is phasing-in charges or delaying implementation appropriate?
[Note: we would appreciate early responses to this question by 24 June 2011 if possible – although we will still consider responses submitted after]

Chapter 3

Question 3.1: Do you agree with our assessment that the approach for the revenue target is reasonable?
Question 3.2: Do you think the principle the maximum import capacity is a cost driver at the voltage of connection is reasonable for charging purposes?

Question 3.3: Do you agree with our view that reactive power flows should be incorporated as part of the capacity that attracts indirect costs and 20 per cent of the residual?
Question 3.4: Is it appropriate to consider the specific assets the customer uses for the calculation of the customer's charge, or would it be more appropriate to consider only the voltage levels the customer uses for the calculation of its charges?
Question 3.5: Do you think that the 'spare capacity' issue we identify should be addressed?
Question 3.6: Do you think notional asset values should take into account assets below the customer's voltage of connection?
Question 3.7: Are there any other demand specific issues that you think we should consider as part of our decision?

Chapter 4

Question 4.1: Do you agree with our proposal to modify the generation revenue target in order to avoid double charging for operations and maintenance costs on sole use assets? This issue aside, do you agree with our view that the approach to calculating a generation revenue target is reasonable?
Question 4.2: Do you agree with our assessment that the approach to scaling is reasonable?
Question 4.3: Do you think it is appropriate for only units exported by non-intermittent generators during the super-red time band to be eligible for credits?
Question 4.4: Do you agree with our proposal that intermittent DG should be eligible for credits as they are deemed to provide network benefits under ER P2/6? If they do become eligible for credits, should the credits only relate to units exported during the super-red time band or is a single credit rate to all units exported more appropriate?
Question 4.5: On import charges for generation dominated mixed import-export:

- Do you agree with our suggested alternative to using the collar of the network use factor for the calculation of the import tariff?
- Do you think that the methodology is appropriate for demand customers connected to generation dominated assets?

Question 4.6: Are there any other generation specific issues that you think we should consider as part of our decision?

Chapter 5

Question 5.1: Do you agree when calculating LDNO charges that DNO costs upstream and downstream of the point of connection should be considered?
Question 5.2: Do you think that DNOs should provide LDNOs with a discount on all non-asset based charges?
Question 5.3: Do you think that varying LDNO discounts only with the point of connection will better achieve a balance between reflecting upstream and downstream costs?
Question 5.4: Do you agree that it may be appropriate in some circumstances for the DNO to pay LDNOs use of system credits?

Chapter 6

Question 6.1: Do you think sole use assets should attract scaling 'costs' to the same extent as shared assets? Does the charging rate on sole use assets seem reasonable given the nature of these assets?

Question 6.2: Do you agree with our view that the arrangements for demand and generation side management agreements are appropriate? Do you think such agreements should be available to all customers?

Question 6.3: Do you agree with our assessment that an explicit reactive power charge is not appropriate?

Question 6.4: On the proposal for sense checking branch incremental costs in LRIC:

- Do you agree with our view that positive cost recovery (ie charges) and negative cost recovery (ie credits) should be considered separately?
- Do you consider that recovery from demand customers and recovery from generation customers should be considered separately?

Question 6.4: Do you think the EDCM should include a mechanism to mitigate the potential volatility from network use factors? We welcome views on measures to mitigate volatility and help customers manage volatility.

Appendix 2 – Project background

1.1 We and the DNOs have consulted since 2000 on achieving more forward looking, locational-based charging models. In 2005, the DNOs adopted new charging arrangements along with a common connection boundary across demand and generation connections. This was noted at the time to be an 'interim' step on the way to more substantive methodology changes. In 2005, we set out our initial thoughts on how to develop longer term charging arrangements for demand and generation.

1.2 In October 2008 we published our decision on the development and implementation of a common distribution charging methodology based on the long run incremental cost (LRIC) approach for higher voltage users and a distribution reinforcement model (DRM) for HV and low voltage (LV) users ("the lower voltages"). The incorporation of new licence conditions to achieve this was blocked by a minority of DNOs due to our decision to adopt the LRIC approach for higher voltage users. In December 2008, we consulted on the next steps for the project in light of this. In our March 2009 decision, we split delivery of the methodology between higher and lower voltages. The issue surrounding the use of the LRIC methodology for higher voltage users was mitigated by allowing individual DNOs to choose between LRIC and the forward cost pricing (FCP) model.

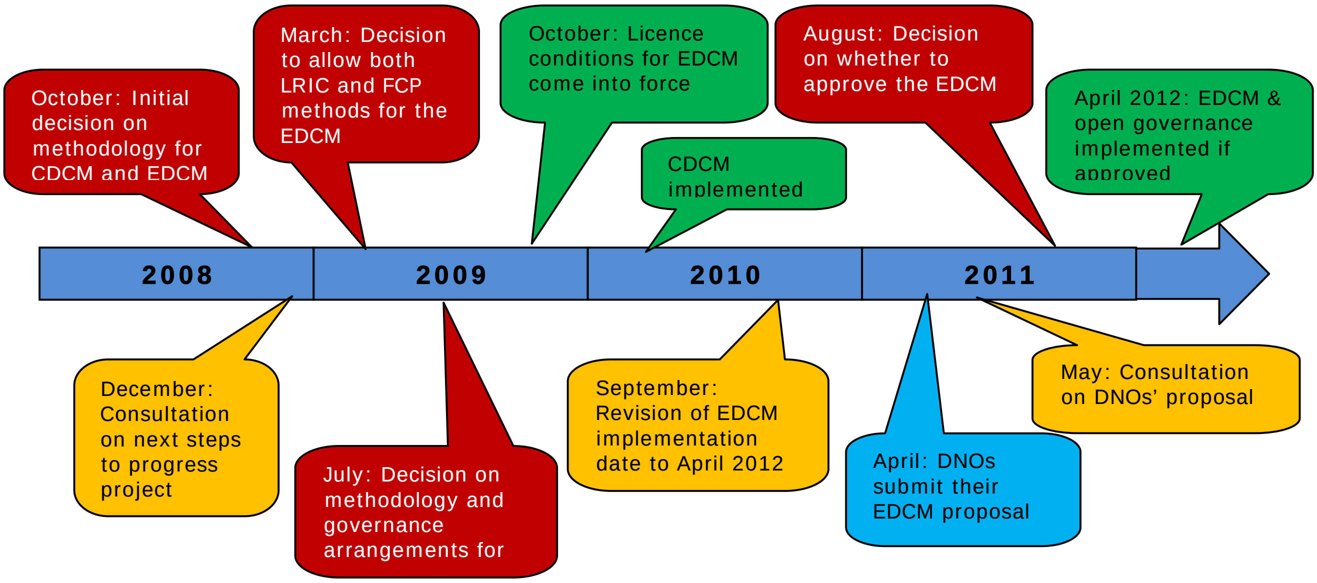
1.3 On 28 August 2009, DNOs published proposals for the common distribution charging methodology (CDCM) to apply to lower voltage users. Ofgem accepted these proposals on 20 November 2009 after relevant conditions had been met. The CDCM was implemented on 1 April 2010.

1.4 In July 2009, we issued a decision on the methodologies to apply at the higher voltages and consulted on the licence changes needed to formalise the requirement on DNOs to implement this by April 2011. The decision allowed for the use of LRIC or FCP to be applied within the EDCM. There were no objections to these changes and on 1 October 2009, licence conditions came into force.

1.5 In September 2010, we published a letter derogating the DNOs from their requirement to submit the EDCM methodology by 1 September 2010. We revised the date of submission to 1 April 2011, for implementation on 1 April 2012. This change in the deadline for submission and implementation was to allow further developments to be made to the methodology and to allow more time for consultation with stakeholders. It was also to provide additional time to consult on the EDCM/CDCM boundary discussed below and allow those customers that would see large movements in their charges time to comment and make any adjustments that could potentially reduce the impact of charge changes.

1.6 Figure A2.1 on the next page shows the project milestones since October 2008.

Figure A2.1 Project milestones – delivery of the EDCM



Appendix 3 - Glossary

A

Allowed revenue

The amount of money that a network company can earn on its regulated business.

Authority

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

B

Bulk Supply Point (BSP)

A substation on a distribution network where energy is transformed from one EHV level to another, eg 132/33kV.

C

Charge Restriction Condition (CRC)

These are special licence conditions that licensees must comply with as part of their licences. CRCs are modified in accordance with Section 11 of the Electricity Act. Failure to comply with CRCs can result in financial penalties and/or enforcement orders to ensure compliance.

Common Distribution Charging Methodology (CDCM)

The CDCM is the name given to the common methodology for calculating use of system charges for customers connected to HV/LV distribution systems. It was developed by the DNOs under standard licence condition 50 and was implemented on 1 April 2010.

Common Methodology Group (CMG)

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

D

Derogation

A derogation is either a complete or partial revocation of a DNO's licence requirement that can be granted by the Authority subject to such conditions and for such periods as the Authority may consider appropriate.

Direct operating costs

The costs of undertaking activities which involve physical contact with system assets, eg labour cost of staff whose work involves physical contact with system assets.

Distribution Charging Methodologies Forum (DCMF)

The DCMF is an industry group run by the ENA that discusses charging developments in relation to electricity distribution networks. See http://2010.energynetworks.org/distribution-charging-methodol/

Distribution Connection and Use of System Agreement (DCUSA)
The DCUSA is an industry agreement which governs connection and use of system arrangements between DNOs, LDNOs, suppliers and some generators on the distribution networks.

Distributed Generator/Distributed Generation (DG)
A generator or generation which is connected directly to a distribution network as opposed to the transmission network. The electricity generated by such schemes is typically used in the local system rather than being transported across Great Britain.

Distribution Network Operator (DNO)
One of 14 incumbent electricity distributors who have defined geographical distribution services areas and who are subject to standard licence conditions and charge restriction conditions in their Electricity Distribution Licences.

Distribution Price Control Review 5 (DPCR5)
DNOs operate under a price control regime, which is 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 has typically lasted five years. DPCR5 is the existing price control that commenced on 1 April 2010 and will end on 31 March 2015.

Distribution Use of System (DUoS) Charges
Charges paid for the use of the distribution network.

E

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

Energy Networks Association (ENA)
The ENA is a trade association for UK energy transmission and distribution licence holders and operators. Its working groups are developing the charging methodologies. See http://2010.energynetworks.org

Engineering Recommendation (ER) P2/6
A guide for electricity distribution network system planning and security of supply.

Extra High Voltage (EHV)
Term used to describe the parts of distribution networks that are extra high voltage, typically these are of a voltage level of 22kV or more.

Extra High Voltage Distribution Charging Methodology (EDCM)
The EDCM is the collective name given to each of the two common methodologies for EHV UoS charging to be developed and submitted by the DNOs on or before 1 April 2011 for approval by the Authority under standard licence condition 50A.

G

Grid Supply Point (GSP)
A ` is any point at which electricity is imported or exported between the National Electricity Transmission System and a 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.

High voltage (HV)
Term used to describe the parts of the distribution networks typically at a voltage level of at least 1kV and less than 22kV.

I

Independent Distribution Network Operators (IDNOs)
A licensed electricity distributor which does not have a distribution services area and competes to operate electricity distribution networks anywhere within Great Britain. They are also subject to standard licence conditions and charge restriction conditions in their Electricity Distribution Licences.

Indirect Costs
The costs incurred undertaking activities which do not involve physical contact with system assets. Such costs include network policy; network design & engineering, project management; engineering mgt & clerical support; control centre; system mapping; call centre; stores vehicles & transport; IT & telecoms; property Mgt; HR & non-operational training; operational training; Finance and Regulation; CEO etc.

Intermittent generation
Generation plant where the energy source cannot be made available on demand.

K

Kilovolt (kV)
A unit of voltage (1,000 volts).

Kilovolt-ampere (kVA)
A unit of active power (1,000 volt-amperes). The values of network capacity and the loads flowing over a network are typically referred to in terms of kVA.

Kilovolt-ampere reactive (kVAr)
A unit of reactive power (1,000 volt-amperes reactive).

Kilovolt-ampere reactive hour (kVArh)
A unit of total reactive power over one hour.

Kilowatt (kW)
A unit of power (1,000 watts).

Kilowatt hours (kWh)
A unit of energy equal to the work done by a power of 1000 watts operating for one hour.

L

Licensed Distribution Network Operators (LDNOs)
A collective term that refers to both IDNOs and DNOs operating networks outside their distribution services areas.

Losses
The distribution of electricity inherently incurs a level of loss because the physical nature of distribution means that electricity is converted to other energy forms (eg heat) and in some cases electricity is illegally taken from the network.

Low voltage (LV)
Term used to describe the parts of distribution networks that are low voltage, typically consisting of a voltage level of less than 1kV.

M

Maximum Demand Condition
A condition where the network is highly loaded, which is used in network planning to identify required demand (load) driven reinforcement works.

Maximum Export Capacity
Means, in respect of a connection point, the maximum amount of electricity which is permitted by the DNO to flow into the distribution system through the connection point.

Maximum Import Capacity
Means, in respect of a connection point, the maximum amount of electricity (expressed in kW or kVA) which is permitted by the DNO to flow from the distribution system through the connection point.

Megawatt (MW)
A unit of power (1,000 kW).

Minimum Demand Condition
A condition where the network is lightly loaded, which is used in network planning to identify required generation driven reinforcement works.

Modern equivalent asset value (MEAV)
The capital cost of replacing an existing asset with a technically up-to-date new asset with the same service capability.

N

Network rates
Formerly called Business Rates. Rates payable to Local Government, as defined in CRC 2 of the electricity distribution licence.

Non half hourly (NHH) metered customers
Customer with a metering system that does not provide measurements on a half hourly basis but rather total consumption to date at time of reading. Settlement is based on profiling NHH data.

Non-intermittent generation
Generation plant where the energy source can be made available on demand

P

Pre-2005 DG

DG whose contractual terms were agreed before 1 April 2005.

Post-2005 DG
DG whose contractual terms were agreed on or after 1 April 2005.

Primary substation
A substation at which the primary voltage is greater than HV and the secondary voltage is HV (covers 132/11kV substations).

R

Reinforcement
Network development to increase capacity in order to relieve an existing network constraint or facilitate new load growth.

S

Sole use asset
As defined in the EDCM submission.

Shared asset
Assets on the distribution network that are not “sole use assets”.

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.

Substation
An electrical substation is a subsidiary station of a distribution system where voltage is transformed from high to low or the reverse using transformers and/or where circuit switching takes place.

Super-red time band
A DNO specific time band, defined for the purpose of calculating EDCM charges. The time band is seasonal representing a period when the network is highly loaded and the annual simultaneous maximum demand is likely to occur.

Sustainable development
Refers to economic development which meets the needs of the present without compromising the ability of future generations to meet their own needs.

T

Transmission exit charges
Transmission exit charges are charges paid by DNOs to National Grid (in its role as GB Transmission Operator) for the use of the transmission network by the DNO.

Appendix 4 - 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:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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