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Consultation on charging methodology for higher voltage distributed generation

Consultation and impact assessment

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Overview:

On 1 June 2012, the DNOs submitted a revised export methodology, the "EDCM for export". This document is our consultation on the DNOs' revised methodology, and incorporates our Impact Assessment. It outlines the DNOs' proposals, sets out our thoughts on key aspects of the EDCM for export, and provides a detailed overview of the impacts on consumers, competition and sustainable development. It also highlights some areas of potential improvement, and discusses options around our proposed approval of the methodology. We 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 its own individual methodologies to set customers' distribution use-of-system (DUoS) 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) is intended to implement common arrangements for those at the higher voltages.

Associated documents

Documents relating to electricity distribution charges can be found on our website at: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx
These include:

- Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements, 31 July 2009 (Ref. number:90/09)
  http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=487&refer=Networks/ElecDist/Policy/DistChrgs

- Electricity distribution charging: decision on the methodology for higher voltage import charges, 6 September 2011 (Ref. number: 116/11)
  http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=760&refer=Networks/ElecDist/Policy/DistChrgs

- Distribution use of system charging – decision and further guidance on higher voltage generation charging, 2 February 2012
  http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=832&refer=Networks/ElecDist/Policy/DistChrgs

- EHV Distribution Charging Methodology (EDCM) Export (generation) charges, Report to Ofgem, 1 June 2012: published alongside this document and by the ENA at http://www.energynetworks.org/electricity/regulation/commercial-operations-group/charging-structure/use-of-system/development/structure-of-charges-edcm/edcm-deliverables-files/7.3-edcm-submission-1st-june-2012.html

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Executive Summary

Purpose and benefits of the methodology

This consultation seeks views on our potential approval of the DNOs' proposed methodology for charging generators at the higher voltages, i.e. the EDCM for export. This is an important piece of the electricity distribution structure of charges project, and contributes to our objective of protecting the interests of current and future network users. The purpose is to ensure that users of the networks pay distribution use-of-system (DUoS) charges that are reflective of the costs that they incur (or benefits that they provide) for the networks. This will have the benefits of limiting the amount of new investment that customers have to pay for, and allocating costs fairly across different customers.

The current developments on the distribution networks support the need for cost-reflective charging. At DPCR5 (the most recent price control review) it was estimated that £2.2 billion in network reinforcement costs (of which £1.6 billion is at the higher voltages) will be required between 2010 and 2015, with more in the RIIO-ED1 price control.

Historically, the DNOs used a range of different charging methodologies covering the different voltages. Having a range of different approaches made it harder for suppliers and users to operate across GB; and some of the approaches could have been more cost-reflective. The purpose of the electricity distribution structure of charges project has been to replace the different methodologies with common GB-wide methodologies. The aims are to make it easier for suppliers and users to operate across GB, and to provide generators with the appropriate incentives to make efficient decisions which might avoid unnecessary network costs.

A Common Distribution Charging Methodology (CDCM) has been in place since 1 April 2010 for customers at lower voltages (LV and HV). The Extra High Voltage Distribution Charging Methodology for demand (import) customers at higher voltages (EHV) has been in place since 1 April 2012. The EDCM for EHV generators (export) is the subject of this consultation. If we approve the DNOs' proposed EDCM methodology for export, then there will be common DUoS charging methodologies for all distribution customers across GB. We expect the DNOs to work with industry participants (e.g. through the open governance arrangements) to improve the methodologies where appropriate.

Our assessment and potential conditions

Our initial assessment of the revised proposals submitted by the DNOs on 1 June 2012 is that:

- they are a substantial improvement on the DNOs' current methodologies;
- they broadly address the issues that we raised in response to their proposals of 1 April 2011; and
- 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 while ensuring charges are cost-reflective.

In addition, the methodology proposes particular arrangements for certain classes of generation customers. It proposes paying credits (known as "super-red credits") to those generators where their output supports the network, e.g. by deferring reinforcement costs. It proposes that intermittent generators (e.g. wind farms) should not receive full credits, but that they should receive a partial credit.

The methodology accounts for the choice that we have given generators that connected before 1 April 2005 (pre-2005 generators). They are eligible for a 25 year exemption from DUoS charges, measured from the date of connection. Our decision allows generators eligible for an exemption to opt in to charges if they wish to do so; we anticipate that some will opt in if they expect to receive a net credit.

We think that there are some areas where the methodology could be improved. However, our initial view is that we would approve the methodology, but that this could potentially be subject to certain conditions on the DNOs. We would particularly welcome feedback on the potential condition that we have set out. It would seek to protect demand customers from paying for credits to intermittent generators unless any network benefit is recognised under the planning standard.

Impact of charges and potential mitigation

Overall, the total overall amount paid by all higher voltage export customers would fall; this difference would be spread amongst other customers. The amount paid by each higher voltage generation customer would change. We estimate that around 90 per cent of those that are currently charged would see a reduction in their export charges. However, for the other customers, there would be increases, some of which could be substantial. Increases in charges have been of ongoing concern to us. We have delayed the project previously, partly to ensure that the DNOs could justify these movements, but also to allow further time for discussions with the most affected customers. We have considered whether we should phase or delay the implementation of the new charges. Our initial view is that it is in best interests of consumers and of the majority of higher voltage generators to implement a common charging methodology as soon as possible. We welcome views about the implementation timetable, were we to approve the methodology.

Next steps

This consultation will run for six weeks, closing on **Tuesday 2 October 2012.** We welcome responses by that date, and would also be happy to meet with customers and other industry participants to discuss issues. We aim to reach a decision for publication by mid October. Using either the EDCM or their existing methodologies, depending upon our decision, the DNOs would publish their indicative charges for 2012/13 in December 2012, and their final charges in February 2013.

1. Introduction

Chapter Summary

In this chapter, we set out the purpose of this consultation, and the background of the project. We discuss which generation customers would be charged under the proposed EDCM for export, including the treatment of pre-2005 generators. Finally, we outline the structure of the remainder of this document.

Question box

Question 1: Have the options available to pre-2005 generators been clearly explained to those generators?

Question 2: What information (or guidance) about the EDCM would be of use to industry participants, and what do DNOs and generation customers think could be provided?

Purpose of this consultation

1.1. On 1 June 2012, the DNOs submitted to us for approval their common EHV distribution charging methodology (EDCM) for export (generation). This methodology covers use of system charges for all extra high voltage (EHV) generators and high voltage (HV) generators that are metered at a primary substation ("the higher voltages"). This is a revised version of the methodology that the DNOs submitted to us on 1 April 2011; we approved the methodology for import (demand), but deferred our decision on the methodology for export (generation).

1.2. This consultation outlines the proposed EDCM for export that was submitted by the DNOs. It sets out our thinking on the key issues that we identified in 2011, and on issues where the DNOs have moved since their last consultation. It also sets out issues where we consider it might be necessary for us to apply conditions to our approval of the methodology. We welcome responses from interested parties on any areas discussed either in this consultation or within the DNOs' submission.

Project background

Purpose and benefits of the project

1.3. The electricity distribution structure of charges project is an important contribution to our objective of protecting the interests of current and future network users. The purpose is to ensure that users of the networks across GB pay distribution use-of-system (DUoS) charges that are reflective of the costs that they incur (or benefits that they provide) for the networks. There are a number of benefits from a cost reflective approach.

1.4. Firstly, we expect cost-reflective charges will, in the long term, reduce the total charges paid by all consumers. By setting cost-reflective prices that encourage network users to make efficient use of the existing infrastructure across GB (e.g. to locate where there is spare capacity), network companies can limit the amount of new investment that customers have to pay for.

1.5. Secondly, it will support sustainable development through the connection of more distributed generation in areas of high demand.

1.6. Thirdly, it will encourage competition. Licensed distribution network operators (LDNOs) will be better able to compete with incumbent DNOs for network projects if costs are more transparent. Suppliers will be better able to compete with one another because the introduction of a common method GB-wide to reduce barriers to entry such as the complexity of dealing with several different methodologies. Generators will be competing with each other on the same basis.

1.7. The present developments on the distribution networks support the need for cost-reflective charging. It is estimated that an estimated £2.2 billion in network reinforcement costs (of which £1.6 billion is at the higher voltages) will be required between 2010 and 2015. Significant further investment is anticipated for the RIIO-ED1 price control. In addition, there are beneficial developments such as the increasing prevalence of distributed generation that increase the challenges of planning and operating the networks.

History of the project

1.8. We and the DNOs have been consulting 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.

1.9. As a result, the Common Distribution Charging 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 their proposed methodology to us on 1 April 2011. We approved the methodology for import (demand), subject to conditions; most of these have been met, and we will shortly be publishing our decision on the final condition based on a report that we have received from the DNOs. We identified a number of issues with the methodology for export (generation), and deferred our decision on that aspect. The DNOs consulted in early 2012 and revised their methodology before submitting their proposal to us on 1 June 2012.

1.10. A Common Distribution Charging Methodology (CDCM) has been in place since 1 April 2010 for customers at low voltages (LV) and high voltages (HV). The Extra High Voltage Distribution Charging Methodology for demand (import) customers at the higher voltages has been in place since 1 April 2012. The implementation of a common methodology for higher voltage generation customers would mean that there were common methodologies for users at all voltage levels.

Customers covered by the EDCM

1.11. The EDCM calculates use of system charges for customers connected to a 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[1]. All other customers (i.e. LV and the remainder of the HV customers) received charges calculated by the CDCM.

1.12. In the information submitted to us, the DNOs listed 1235 sites that would be defined as designated EHV properties. Of these, 1219 sites have import connection agreements; these include large industrial sites such as glass works, and large commercial sites such as airports. 608 sites have export connection agreements; these include industrial complexes with excess on-site generation, and dedicated generators, such as wind farms. Of the 608 sites with export connections, 6 have two separate connections, giving a total of 614 export connections. This would have an impact upon the charges for those sites. However, for the purposes of considering the overall charges across all customers, the distinction between the number of generation sites and the number of export connections is not significant. Unless otherwise stated, this consultation refers to the number of export connections.

1.13. Of the 614 connections, 25 are "placeholders" for there is no agreed export capacity. The remaining 589 can be divided in the following ways:

- 362 pre-2005 / 227 post-2005
- 376 intermittent / 213 non-intermittent
- 157 post-2005 connections have a previous charge[2]

[1] These customers are defined as 'Designated EHV Properties' under SLC 50A.11 of the electricity distribution licence.

[2] Please note that the phrase "previous charge" is based on the DNOs' submission. They used it to refer to customers that are currently charged in 2012/13; "previous" is from the point of view of 2013/14, when the EDCM could be implemented. For consistency, we use this terminology. Please also note that the illustrative EDCM charges are based on 2012/13 data; so comparing the previous and illustrative charges shows the impact of introducing the EDCM, with common input data. The actual charges for 2013/14 would be based on new input data, and so would differ from the illustrative charges. This is discussed further in the Impact Assessment.

Pre-2005 generators

1.14. As can be seen in the previous section, there is a significant number of generators that connected on terms agreed before 1 April 2005, the so-called pre-2005 generators. We have consulted extensively on the issue of introducing DUoS charges for pre-2005 generators, and it is important to consider the policy that has been developed.

1.15. Under the pre-2005 arrangements, generators paid deep connection charges. In 2005, two changes occurred: the connection charging boundary was changed, introducing shallowish connection charges for generators connecting thereafter; and DUoS charges were introduced for generators. Pre-2005 generators were given a five year exemption from DUoS charges to recognise this change in circumstance and to allow more long term cost reflective methodologies to be introduced.

1.16. In the price control that runs from 2010 to 2015, we said all generators should be charged on same basis. However, we recognised that this could result in some pre-2005 generators making double payments for O&M costs that they had already paid for upfront as part of their connection fees. We considered the option of some pre-2005 generators receiving refunds.

1.17. We set out in our decision[3] of 20 February 2012 that pre-2005 generators will be eligible for an exemption from DUoS charges for a period of 25 years from the date of connection, in order to avoid double payments for O&M charges. We have subsequently clarified the meaning of date of connection[4]. So, for example, on 1 April 2013, any generator that connected between 1 April 1988 and 31 March 2005 would be eligible for an exemption. Generators that connected before that date would have expired exemptions, and so would be charged under the EDCM for export. Each exemption will expire once the connection is 25 years old.

1.18. We are keen that all distribution customers are subject to a common methodology. Therefore, each pre-2005 generators will have the choice to waive its exemption and opt into the EDCM for export. It would not make financial sense for pre-2005 generators to opt in if they would face a net charge. However, as discussed in more detail in Chapter 2, the DNOs' proposed EDCM for export includes paying super-red credits to some generators. In some cases, the credit would exceed the charge, giving the generator a net credit; were this to be case of for a pre-2005 generator, then that generator could decide to opt in to the EDCM for export.

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[3] Distribution use of system charging – decision to allow a time-limited exemption for pre-2005 distributed generators, 10 February 2012
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=837&refer=Networks/ElecDist/Policy/DistChrgs

[4] Further decision on time-limited exemption from use of system charges for pre-2005 generators, 19 March 2012
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=838&refer=Networks/ElecDist/Policy/DistChrgs

1.19. The DNOs have modelled three scenarios to understand the impacts of different numbers of pre-2005 generators that are eligible for an exemption deciding to opt into the EDCM for export. These are discussed in more detail in the Impact Assessment.

1.20. We would like to know whether the options available to pre-2005 generators that are eligible for exemptions have been clearly explained to those customers.

Stakeholder engagement

1.21. It has been important to work with stakeholders throughout the electricity distribution structure of charges project. We and the DNOs have consulted extensively. For the EDCM, the DNOs have published a number of consultations on their proposed methodology. Before the submission of the version (for import and export) on 1 April 2011, they published several consultations in 2010 and 2011. Before the submission of the revised version (for export) on 1 June 2012, they published a consultation in March 2012.[5]

1.22. 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.

1.23. We understand that some industry participants would like to know more about the details of the EDCM models. We note that the DNOs published blank versions of the model alongside their submission of 1 June 2012. We understand some details of the data are confidential, and hence cannot be divulged. We would welcome views from other parties about what further information (or guidance) would be of use to them, and why. We would also welcome view from the DNOs and generation customers about what information (or guidance) could be provided.

Open governance arrangements

1.24. Once implemented, the EDCM for export will be subject to an open 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.

1.25. Any DCUSA party can submit proposals to modify the methodology. These parties include DNOs, LDNOs, suppliers and generators, as well as by other parties

[5] EDCM DG Consultation, 1 Mar 2012: http://www.energynetworks.org/electricity/regulation/commercial-operations-group/charging-structure/use-of-system/development/structure-of-charges-edcm/consultation-files/edcm-dg-consultation-1-mar-2012.html

materially affected by the methodology (with permission from us). We note that the DNOs are required under the licence to review their methodology at least once per year.

Structure of this document

1.26. The rest of this document is structured as follows:

- Chapter 2 provides an overview of the proposed methodology for export, and sets out our views on what we believe to be the key issues;

- Chapter 3 sets out the next steps for the process; and

- Appendix 1 sets out our Impact Assessment for implementing the proposed methodology, based upon data provided by the DNOs. It also presents our views on the impacts of a potential condition of any approval.

2. Charging proposals for generation customers

Chapter Summary

In this chapter, we set out the principles and objectives of the EDCM, how we assess the proposed EDCM for export, and our options for our decision. We then provide an overview of the proposed methodology. We give our views, focusing on four key issues, and set out a potential condition that could apply if we were to approve the methodology.

Question box

Question 1: Do you think that the proposed methodology includes the relevant issues, and has not omitted any relevant issues?

Question 2: Do you agree with our understanding that the interactions between super-red credits for intermittent generators and Engineering Recommendation P 2/6 could result in demand customers paying for credits when no network benefit is recognised under the planning standard?

Question 3: Is the treatment of sole-use asset costs appropriate?

Question 4: Is the calculation of the revenue pot appropriate, in particular the approach to the DPCR4 contribution, and proposed figure for the O&M rate?

Question 5: Is the approach to allocation of the revenue pot appropriate?

Question 6: Do you have any views on the calculation of LDNO charges through the extended "Method M" for CDCM-like customers, and through the separate methodology for EDCM-like customers?

Question 7: Do you have any other comments about the issues that we have noted, or about any other points?

Question 8: Is it appropriate for us to approve the methodology?

Question 9: Is it appropriate for us to place the potential condition that we have suggested, and are there any other conditions that respondents feel would help to better meet the Relevant Objectives?

Question 10: Do you think that we have identified the important impacts in our Impact Assessment?

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 from licensed distribution network operators (LDNOs), between suppliers, and between generators; and
- 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 propose improvements thus allowing for the development of the methodology over time.

How we assess and approve the EDCM for export

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;

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[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: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=447&refer=Networks/ElecDist/Policy/DistChrgs

[7] As defined under SLC 50A.7-10.

[8] SLC 50A.36.

- compliance with the EDCM results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the cost incurred, or reasonably expected to be incurred, by the licensee in its Distribution Business; and

- 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. The DNOs set out their own assessment of the EDCM for export against the Relevant Objectives in paragraphs 33-56 of their submission.

2.5. In developing the EDCM for export, the DNOs were also required to have regard to the principles and assumptions that we used to describe how the methodologies should work. These were originally set out in our decision of 31 July 2009[9], and have subsequently been amended by a derogation that we issued on 19 May 2012[10]. This stated that the DNOs do not need to submit a methodology which contains LRIC or FCP charges. This left the DNOs with the freedom to use these methods for the calculation of super-red credits to generators, and, if they did use these methods, the choice over which methodology (FCP or LRIC) to use in their submission.

2.6. We may approve the methodology in full, or subject to conditions[11]. Any conditions would specify the further actions that the DNOs would need to take in order for the EDCM for export to better achieve the Relevant Objectives. They would also outline the timeframe in which any actions would have to be completed.

Overview of the EDCM for export

2.7. 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.

2.8. The DNOs' report (published alongside this consultation document) sets out specific charging arrangements for generation customers (customers that export electricity to the network) at higher voltage levels. The report discusses the main

[9] 'Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements', 31 July 2009: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=487&refer=Networks/ElecDist/Policy/DistChrgs
[10] Derogation issued under SLC 50A, 18 May 2012: http://epr.ofgem.gov.uk/Pages/EPRInformation.aspx?doc=http%3a%2f%2fepr.ofgem.gov.uk%2fEPRFiles%2fDerogation+issued+under+SLC+50A+-+18-05-2012.pdf
[11] SLC50A.20-22.

aspects of the proposed methodology. Here we highlight certain key points, including aspects that have changed since the previous submission.

Summary of what is in the methodology

2.9. The EDCM aims to generate cost-reflective and site-specific charges for import and export. For each customer the charge aims to reflect the cost of using the network at their location. For each generation customer, the key factors are:

- its export capacity;
- the value of the assets that are exclusively for its use; and
- if it is eligible for super-red credits, the amount that it exports during times of peak demand.

2.10. The EDCM calculates charges for demand customers and generators. The calculations for demand charges are discussed in our May 2011 consultation[12]. The proposed EDCM for export charges involves five main steps:

- Step 1 is the application of load flow techniques and the LRIC or FCP methodologies to determine the locational demand-led reinforcement charge elements, known as Charge 1. This is part of the methodology for calculating import (i.e. demand) charges.
- Step 2 is the calculation of locational credits (p/kWh) to qualifying export charges based on the FCP or LRIC Charge 1 from Step 1. This is discussed in Issue 1, below, and in the Impact Assessment.
- Step 3 involves the calculation of an EDCM generation revenue target (£/yr). This is discussed in Issue 3, below.
- Step 4 is the allocation of this target to export charges as a capacity charge (p/kVA per day). This value is also used as the value of the exceeded capacity charge (p/kVA per day). The capacity charge is discussed below in Issue 3.
- Step 5 is the calculation of fixed charges (p/day) associated with sole use assets associated with export charges. This is discussed below in Issue 2.

2.11. The main additions and amendments to the methodology between the version of 1 April 2011 and revised proposal of 1 June 2012 are:

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[12] Electricity distribution charging methodologies: distribution network operators (DNOs') proposals for the higher voltages, 20 May 2011 (Reference number: 67/11): http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=687&refer=Networks/ElecDist/Policy/DistChrgs

- Removal of FCP and LRIC charges for calculation of export charges.
- Inclusion of FCP/LRIC credits for intermittent generation, but limited to reinforcement at network levels other than the level of connection. This is discussed in Issue 1, below.
- Revised method to calculate the generation revenue target. This is discussed in Issue 3, below.

Summary of what is not included in the methodology

2.12. As set out in below, certain aspects are not included in the methodology. We welcome respondents' views on whether it is appropriate for these to not be included.

2.13. The approach used by the DNOs does not produce reactive power charges for generators. It uses parameters that do not lend themselves to the direct calculation of reactive power charges; it uses the value of sole use assets (to create the fixed charge), and the export capacity (to create the capacity charge). Through the super-red credits, the methodology does indirectly include charges that account for reactive power and encourage efficient behaviour. If a generator were to increase its power factor, then it could reduce the contracted export capacity that was needed to export its active power, hence reducing its capacity charge. An increased power factor would also allow the generator to export more units (kWh) of active power in any given period of time, including during peak demand times, hence allowing it to earn more credits.

2.14. The proposed methodology includes an option for transmission exit credits. These are capacity-based payments to qualifying generators that have agreements with a DNO to export power during supergrid transformer outage conditions. We understand that, as of the time of submission, no generators were eligible for these credits.

2.15. The main aspects that have been removed from the methodology between the version of 1 April 2011 and revised proposal of 1 June 2012 are:

- Removal of charges relating to generation-led reinforcement based on FCP/LRIC methodologies. This is in line with our decision of 2 February 2012[13], which we reached due to concerns over the cost reflectivity of the LRIC/FCP charge for generators in certain circumstances and the potential volatility of the charge itself which could be impacted by other generators' behaviour.

[13] Distribution use of system charging – decision to allow a time-limited exemption for pre-2005 distributed generators, 10 February 2012 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=837&refer=Networks/ElecDist/Policy/DistChrgs

- Removal of proposals for reduced EDCM charges for generators with generation side management (GSM) agreements. This relates to the removal of charges relating to generation-led reinforcement based on FCP/LRIC which the previous method of calculating GSM charges was based upon. Essentially, without generation-led reinforcement charges no method has been identified for calculating GSM charges.

Our views on the proposed EDCM for export

2.16. This section sets out our overall views and then discusses four key components of the methodology in more detail.

Overall comments

2.17. Our initial assessment of the revised proposals submitted by the DNOs on 1 June 2012 is that:

- they are a substantial improvement on the DNOs' current methodologies;
- they broadly address the issues that we raised in response to their proposals of 1 April 2011, and in our subsequent publications; and
- the methodology largely meets the objectives set out for the project.

2.18. The methodology is common to all DNOs, which makes it easier for suppliers and licensed distribution network operators (LDNOs) to operate across DNO areas. It gives price signals about where it most beneficial to connect on the network while ensuring that charges are cost-reflective.

2.19. We have identified four particular issues on which we would appreciate stakeholders' views, as set out below. As discussed at the end of this chapter, these could result in us requesting improvements to the methodology, or placing conditions on any approval of the proposed methodology. Our initial view is that we would approve the methodology, potentially subject to a condition relating to super-red credits for intermittent generators.

2.20. We also note that the DNOs' submission contained a number of data issues. In some cases, different DNOs seemed to have interpreted aspects of the methodology in slightly different ways; in other cases, there were what appear to be errors with the input data. We worked with the DNOs to resolve these issues for our analysis. However, the issues highlighted the importance of consistent use of the model and careful treatment of data. Were we to approve the methodology, we expect the DNOs to check the model and its input data carefully before using it, and to ensure that charges (both indicative and final) are free from errors.

Issue 1: super-red credits for intermittent generation

2.21. The methodology proposes paying super-red credits to some generators. As discussed below, these generators are those that help to meet local peak demand. The DNOs propose that intermittent generators should be eligible for credits; we set out below why we think that this might not be appropriate under the current circumstances.

2.22. The DNOs use Engineering Recommendation (ER) P2/6[14] (the "planning standard") when designing their networks. This document sets out the contribution that different types of generators make to security of supply. It specifies that some forms of generation can be more fully relied upon to generate when required, and so can help to meet demand at peak times; intermittent sources cannot be relied upon to do so.

2.23. The DNOs work on the (reasonable) assumption that demand in each area will grow at a steady rate, such that the demand profile throughout the year (including peak demand) will gradually rise. This means that reinforcement (extra capacity) will be needed at some point in the future to ensure that the network has sufficient capacity to link the area's demand customers to sufficient generation to meet the new, higher peak demand. However, if a generator is located in that area, its output can help to meet peak demand in that local area. If that generator can be expected to continue to help to meet that demand, then the DNOs could defer reinforcement of the network between those customers and other sources of generation. This brings benefits to consumers by deferring those reinforcement costs; to reflect this benefit, the DNOs propose to pay super-red credits to generators that help to secure local peak demand.

2.24. For some generators, the credit would be larger than the charge, and they would receive a net credit. The super-red credits are paid through demand customers' charges. This seems reasonable, given that the alternative is that demand customers would pay higher charges in order to fund reinforcement works.

2.25. The DNOs' propose two types of credits: a local credit if investment is deferred at the voltage level of the generator's connection; and a remote credit if investment is deferred at voltage levels above the generator's connection. Credits are paid after the event, based upon actual output (i.e. p/kWh) during peak periods; the DNOs' indicative charges include estimates of the likely credits for the coming year based on load factor, expected generator behaviour, etc.

2.26. The DNOs propose that intermittent generators should not receive full credits. This is because they cannot be relied upon to generate at the time of local peak demand, and therefore cannot be used as justification for deferring local reinforcement works. However, the DNOs do propose that intermittent generators

[14] Engineering Recommendation P2/6, Security of supply, July 2006; available from the Energy Networks Association

should receive a partial remote credit (in proportion to load factor) to reflect the aggregate effect of a number of intermittent generators. The DNOs argue that, given a large number of intermittent generators spread over an area, there is a larger probability that some of them will contribute to meeting peak demand. They can be used as justification for deferring remote reinforcement, and so should be eligible for remote credits. However, they should not be full remote credits, but should be related to the generators' load factors.

2.27. We are in favour appropriate credits being paid to all generators for benefits that they bring to the network, including where they help to defer network investment and hence reduce costs for consumers. Where intermittent generation brings such benefits, it should be recognised.

2.28. However, we are concerned that the proposed credits might not be consistent with how the DNOs plan their networks. Our understanding of Engineering Recommendation P 2/6 is that it does not attribute intermittent generation with any benefits for securing supply. Therefore, the DNOs would be obliged to reinforce the network for demand customers as if the intermittent generation were not present. The result would be that consumers would be paying for EDCM super-red credits and for network reinforcements in the same area; they should pay for one or the other, but not for both. This would not be cost reflective and we do not think it would be in the interests of consumers.

2.29. Our current thinking is that these generators do not provide a network benefit under the current planning standard, and that it would not be appropriate for demand consumers to pay them credits. We are minded to place a condition (as set out below) on any approval such that intermittent generators would not receive credits unless the approaches of the EDCM for export and P 2/6 are reconciled to ensure that the methodology is cost-reflective and protects consumers. The potential impacts of such a condition are considered in the Impact Assessment.

2.30. We welcome views on whether our understanding is correct. In particular we would welcome any evidence as to why the DNOs proposed approach would be cost reflective or in the interests of consumers.

2.31. We also note that some pre-2005 intermittent generators may have already opted into the EDCM for export in the expectation of receiving a super-red credit that would exceed their potential charge. If we were to place a condition such that super-red credits were to not be available to intermittent generators, then we think it would be appropriate for these pre-2005 generators to be allowed to reconsider their decision. We welcome feedback from the DNOs on whether any generators fall into this category.

Issue 2: sole-use assets

2.32. Each generation customer has certain assets that only it uses (sole-use assets). It is appropriate that these costs are borne by the customer alone. The capex costs of sole use assets are paid through the connection charge, and so are not covered by DUoS charges. There are also DNO direct operating costs and network rates associated with generation sole use assets. The DNOs propose that these should be allocated to the generator, and paid through a fixed charge (p/day). That is, it is a payment from the generator to the DNO to cover the non-capex costs for assets that the DNO operates solely for that generator. The fixed charge is derived from the value of the customer's generation sole use assets used, expressed in the form of a modern equivalent asset value (MEAV) in pounds.

2.33. We believe that this proposal would result in cost reflective sole-use asset charges for generators. The same approach is used for EDCM demand customers which we have approved. For mixed sites (generation and demand), the methodology splits sole-use asset costs between the generation and demand tariffs in proportion to their respective maximum capacities, avoiding double charges. Similarly, for any site that was originally connected as a single customer but that has subsequently been split into multiply sites, the DNOs propose to allocate the sole-use asset MEAV in proportion to the maximum capacities of the individual sites.

2.34. We note that sole-use asset charges would be higher for generators that are located further from the network or in remote areas, where connections assets are longer and more expensive to maintain. This is discussed further in the Impact Assessment.

2.35. We think that the treatment of sole-use asset costs is appropriate. We welcome views on this.

Issue 3: revenue pot

2.36. Some network assets are used by more than one customer; the costs associated with these assets are shared amongst customers. The proposed EDCM for export calculates the total shared-asset costs attributable to generators, and then allocates them between the generators. We have considered these two points in turn, below.

2.37. The DNOs have tried to identify the costs attributable to generators; these consist of capex and opex (the latter just O&M costs). They believe that generators can be split into three distinct categories, based upon their connection dates; different types of shared-asset costs can be attributed to each category. Therefore, they propose that each DNO's revenue pot should be the sum of the following three elements:

- **Pre-2005 generators**: The DNOs have identified no capex costs because these generators paid deep connection charges. They identified O&M (20p/kW) as the only cost imposed by pre-2005 generators, and they propose that this should contribute to the revenue pot.

- **2005-2010 generators**: The DNOs have identified costs imposed by 2005-2010 generators through the DPCR4 DG Incentive. The DNOs propose that this contribution to the revenue pot should be equal to the amount of revenue added to the DNO's allowed revenue in the charging year in respect of the distributed generation incentive scheme (DG Incentive) for qualifying generation connected between 1 April 2005 and 31 March 2010. This allocation is done on the basis of the ratio of EDCM export capacity connected between 1 April 2005 and 31 March 2010 to the total DG capacity connected between 1 April 2005 and 31 March 2010. This includes capex and opex, but the breakdown is not clear.

- **Post-2010 generators:**
  The DNOs have identified both capex and opex costs imposed by 2005-2010 generators. The DNOs propose that the capex contribution to the revenue pot should be an allocation of the cost of capital associated with qualifying capital expenditure incurred, or forecast to be incurred, by the DNO to enable the connection of distributed generation to its network on or after 1 April 2010. This allocation is done on the basis of ratio of EDCM export capacity connected on or after 1 April 2010 to the total DG capacity connected on or after 1 April 2010. The DNOs propose that the opex contribution to the revenue pot should be an estimate of the operation and maintenance (O&M) costs (20p/kW, as for the pre-2005 generators) that might be incurred by the DNO in connection with network assets that are built to accommodate new generation, in respect of assets associated with post-2010 generators.

2.38. The DNOs submitted their report on the basis that this is the appropriate way to calculate the revenue pot. Based on the evidence presented by the DNOs, we think that the approach seems reasonable. However, we would welcome views on whether the approach to the DPCR4 contribution to the revenue pot is appropriate.

2.39. A key part of the calculation of the revenue pot is the calculation of the O&M rate (£/kW per yr). The DNOs have proposed a rate of £0.20/kW, with the following reasoning. The DNOs looked at data from the current price control for forecast capital expenditure (excluding expenditure on sole use assets) per unit of new generation capacity. The costs range from 0 to £67/kW, with a simple average £20.02/kW, a weighted average (weighted by new capacity) of £19.74/kW, and a median of £15.66/kW. DNOs believe that an O&M rate of 1 per cent of the forecast capital expenditure (excluding expenditure on sole use assets) is reasonable. When applied to the estimated costs above, this would suggest an O&M contribution of approximately £0.20/kW. The O&M rate of 1 per cent is consistent with rates used for the DG Incentive revenue calculations. However, we note that the DG Incentive resulted in an O&M rate of £1/kW. We welcome views on whether the proposed figure is appropriate.

2.40. Once the each DNO's revenue pot has been calculated, it has to be allocated between generators. For demand customers, the DNOs use power flow analysis to allocate some costs. However, a power flow analysis approach is not as applicable to generation as it does not produce useful data; the power flows are not as intuitive and go in a variety of directions. Therefore, the DNOs propose that the revenue pot should be allocated between generation customers by means of capacity charges (p/kVA per day). This same value is then used for the exceeded capacity charge.

2.41. The DNOs submitted their report on the basis that this is the appropriate way to allocate the revenue pot between generators. Based on the evidence presented by the DNOs we think that the approach seems reasonable and it protects consumers from having to pay for costs attributable to DG. However, we would welcome views whether there could be a more cost-reflective approach to the allocation.

2.42. We note that the policy for pre-2005 generators would have the effect of reducing charges for other generators. Increasing numbers of pre-2005 generators would enter the EDCM for export, some because their exemptions expire, and others because they opt in to the EDCM for export. As they enter the EDCM for export, the design of the proposed methodology means that they would add smaller costs (just 20p/kW for O&M) to the revenue pot. But they, and all other generators, would pay a share of the full revenue pot (opex and capex), thereby reducing the charges for other generators compared to if the pre-2005 generators were not added to the EDCM for export. This does not seem unreasonable as it will ensure that all generators contribute towards the cost of shared assets and face the same approach to charging.

Issue 4: LDNO charges

2.43. The methodology explains the calculation of LDNO charges. These apply when an LDNO has a distribution system that qualifies as a designated EHV property. This can be in one of two situations.

2.44. Firstly, if a customer is connected to an LDNO's network, but it would have qualified for a CDCM charge had it been connected directly to the DNO's network, then it is called a "CDCM-like customer". This approach gives a discount in the charge that the LDNO pays to the DNO.

2.45. The charges are based on an extended form of method M (the extended price control disaggregation model) which is already in place. We have not identified any further issues with this since our decision on import charges in 2011. However, we welcome views from stakeholders on whether the approach is appropriate.

2.46. Similarly, if a customer that is connected to an LDNO network would have qualified as a designated EHV property had it been connected directly to the DNO's network, then it is called an "EDCM-like customer". This approach applies the EDCM to the boundary between the DNO and the LDNO, i.e. the LDNO pays charges as if the EDCM customer was connected at that point.

2.47. We note that this proposed methodology does not provide LDNOs with any discounts. Within the demand methodology a discount was provided for indirect costs to allow the LDNOs scope to recover their own indirect costs. However no indirect costs are recovered through the EDCM for export. We believe that this is why no discounts are passed on to LDNOs, and that they are able to recover those costs through demand charges where indirect costs are included. We welcome views on whether this is appropriate. We expect the DNOs to keep the methodology under review to ensure that LDNOs are fairly treated and receive appropriate discounts.

Potential conditions and improvements

2.48. As set out above, we think that the proposed methodology is a distinct improvement on the current arrangements. We would welcome views on the issues that we have set out above, and we will consider how best to address them, were we to approve the methodology. We could decide that an issue requires no action. We could decide that an issue requires work to improve that aspect; this could be addressed through work by the DNOs prior to implementation, or through the open governance process once the methodology had been brought under the DCUSA. Or we could decide that an issue is sufficiently important that any approval should be subject to certain conditions on the DNOs.

2.49. At present we are not considering any particular improvements or conditions relating to Issues 2, 3 and 4. At present, the one potential condition is based on Issue 1:

- **Super-red credits for intermittent generation**: Intermittent generators should not receive credits unless the approaches in the EDCM for export and Engineering Recommendation P 2/6 are reconciled in order to avoid consumers paying for credits where no network benefit is recognised under the planning standard.

2.50. We would welcome suggestions for potential improvements and conditions that respondents feel would be help to better meet the Relevant Objectives, relating to any of the four issues that we have discussed, or to any other relevant issues.

3. Next steps

3.1. This consultation will run for 6 weeks, closing on Tuesday 2 October 2012. We welcome responses by that date. We would also be happy to meet with customers and other industry participants to discuss issues. We will then consider all of the views, and aim to reach a decision for publication by mid October.

3.2. The DNOs would publish their indicative charges for 2012/13 in December 2012, using either the EDCM for export or their existing methodologies, depending upon our decision, and their final charges in February 2013.

3.3. We recognise that, were we to not approve the EDCM for export for implementation in 2012/13 (or were to approve it with significant amendments or conditions), some generators would be subject to significantly different charges or credits than they had anticipated. For example, our views about credits for intermittent generation could have an impact upon the merits of some generators opting into the EDCM for export. We therefore propose that, were we to approve the methodology, those that have opted into the EDCM for export should be allowed to reconsider their positions and could regain their exemptions. We note that eligible generators are able to opt into the EDCM for export at any point in time.

Appendices

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Appendix 1 - Impact assessment

Appendix Summary

This appendix sets out our Impact Assessment for the decision on whether to approve the proposed EDCM for export. It starts by setting out our options, and then provides an overview of the possible impacts against key criteria, and on various groups of consumers.

Options and baseline for assessment

1.1. This Impact Assessment sets out or views of the likely impacts of the different options that are open to us. The options are as follows:

Option 1: approve the methodology as submitted by the DNOs

1.2. This option would involve us approving the EDCM for export that the DNOs submitted on 1 June 2012, in the same form that it was submitted without any changes.

Option 2: approve the methodology with conditions

1.3. Under this option, we would approve the methodology as it was submitted by the DNOs, potentially subject to conditions on the DNOs. Standard Licence Condition (SLC) 50A.21-22 of the electricity distribution licence sets out the process by which we can place conditions on the DNOs.

1.4. The potential condition that we are considering is set out at the end of Chapter 2, above. Option 2 also extends to other conditions that we might make, following feedback through the current consultation process.

Option 3: do not approve the methodology

1.5. This option would involve rejecting the DNOs' proposed EDCM for export on the basis that it does not meet the Relevant Objectives set out in SLC 50A. The DNOs' existing methodologies would continue to apply and they would remain obliged to review them annually and bring forward changes as necessary.

1.6. The result would be that the potential benefits from a more cost reflective and common methodology would not be realised.

1.7. Our thoughts are that if we do reject the proposed EDCM for export, we would require the DNOs to bring forward an EDCM for export that does meet the Relevant Objectives at a revised date.

1.8. This Impact Assessment uses Option 3 as the baseline to assess the impact of the EDCM export charges. That is, it compares the proposed methodology with the situation in which the DNOs continue to use their individual charging methodologies (for the generation element (export) of charges for customers at the higher voltages).

Scenarios modelled by the DNOs

1.9. The DNOs have provided data under three scenarios. In each scenario, all post-2005 generators are charged under the EDCM for export and are hence liable for charges / credits. However, the number of pre-2005 generators under the EDCM for export varies between the scenarios:

- Scenario 1: Includes only those pre-2005 generators that had opted in as of 1 June 2012.
- Scenario 2: Includes all pre-2005 generators.
- Scenario 3: Includes only those pre-2005 generators that are forecast to receive a net credit.

1.10. Alongside their 1 June 2012 submission, the DNOs published tables with two key figures for each tariff under each scenario. Our understanding is that the DNOs wanted to present data that provides an indication of the effects of implementing the EDCM for export. Therefore, they applied the different methodologies to the same input data:

- "Export charge in previous charging year (£/year)" is the net charge / credit for a customer based upon 2012/13 data that is being levied in 2012/13 under an existing methodology.
- "Total for generation (£/year)" is the net charge / credit for a customer based upon data for 2012/13 that would have been levied in 2012/13 had the EDCM for export been in place.

1.11. The data for "total for generation" show the DNOs' illustrative charges for all customers that would be charged under the EDCM for export in each scenario.   For customers that have a "previous charge", the figures illustrate the extent to which indicative charges vary from the present values; for those customers that are not presently charged, there is no comparison to make. Please note that the phrase "previous charge" is based on the DNOs' submission. They used it to refer to customers that are currently charged in 2012/13; "previous" is from the point of view of 2013/14, when the EDCM for export could be implemented. For consistency, we use this terminology.

1.12. Please also note that, according to information from the DNOs, the illustrative EDCM export charges are based on 2012/13 data. So comparing the previous and illustrative charges shows the impact of introducing the EDCM for export, with common input data. The actual charges for 2013/14 would be based on new input data, and so would differ from the illustrative charges. These figures are helpful for our assessment of the impacts of implementing the methodology, and they are informative for customers and other stakeholders.

1.13. However, as stated in the DNOs' report, "[t]hese illustrative charges are not intended to be a reasonable forecast of eventual export charges that might apply". The DNOs have not published actual forecast charges that would be levied in 2013/14 were the EDCM for export to be in place. The charges for the first year of the EDCM for export would be determined by the DNOs using the latest data, and would differ from the illustrative figures for 2012/13. Customers should consult with the DNOs in order to better understand the possible charges for 2013/14.

1.14. With these caveats in mind, we think that scenario 3 is the most relevant for our assessment. It is based on the assumption that those generators that can choose whether to opt in to the EDCM for export will make the decision that is to their financial benefit. Scenario 1 is similar to scenario 3, but was simply a "snap shot" of those that had opted in as of a particular point in June 2012. Scenario 2 is unrealistic as a representation of the first year of implementation. It does, however, give an indication of the situation that would result once all exemptions have expired in several years' time. Although, by that time, charges will have been changed by various factors (e.g. by other generators connecting).

1.15. However, as discussed in Chapter 2, we have concerns over the proposal to pay partial remote credits to intermittent generators. We are considering applying a condition to any approval, such that intermittent generators would not receive any credits until the DNOs can reconcile the approaches of the EDCM for export and Engineering Recommendation P2/6.

Impact on consumers

1.16. Our principal objective is to protect the interests of existing and future consumers. This is the totality of customers, broader than those generators that would be charged under the EDCM for export. We can consider this in two ways: the expected benefits of the EDCM for export; and the impact that it would have upon the DUoS charges of consumers.

Benefits from the EDCM for export

1.17. As discussed in more detail in the main section of this document, all other electricity distribution customers are charged under common methodologies. The EDCM for export would mean that that all customers are charged under common methodologies. This will provide cost-reflective charges, that will bring the following benefits:

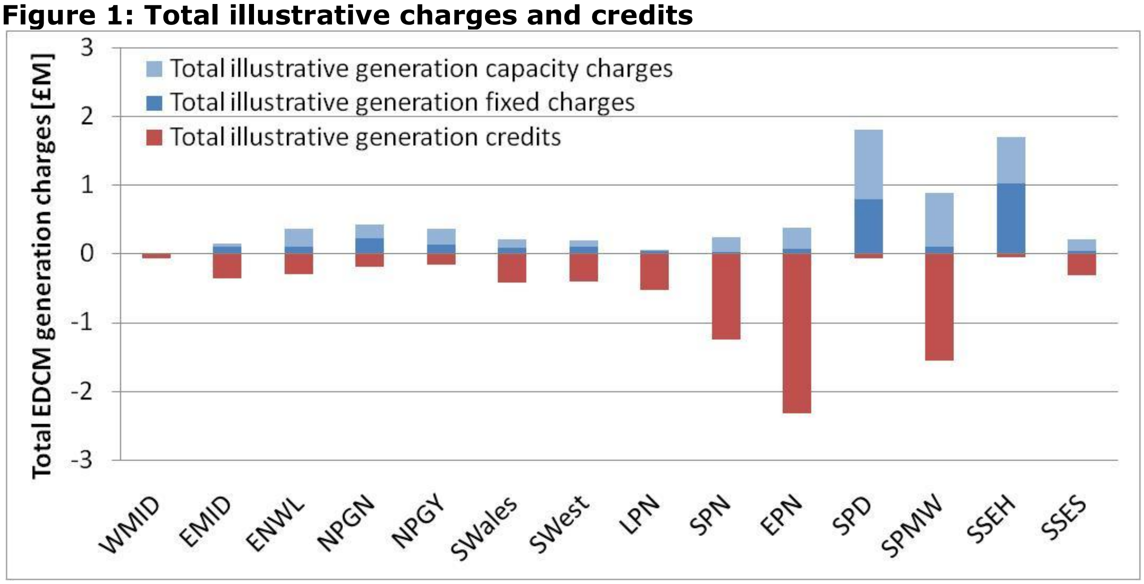
- encourage network users to make the most efficient use of the existing infrastructure across GB (e.g. to locate where there is spare capacity), thereby allowing network companies to limit the amount of new investment that customers have to pay for;
- support sustainable development through the connection of more DG in areas of high demand; and
- encourage competition between LDNOs, between suppliers, and between generators.

Impact on charges

1.18. The benefits listed above would be seen over the years after any introduction of the EDCM for export. However, if the EDCM for export was introduced, it would have an immediate impact upon the DUoS charges of consumers. The data below illustrates that this impact would be very small. It is helpful to start by looking at the details of the illustrative EDCM export charges and credits.

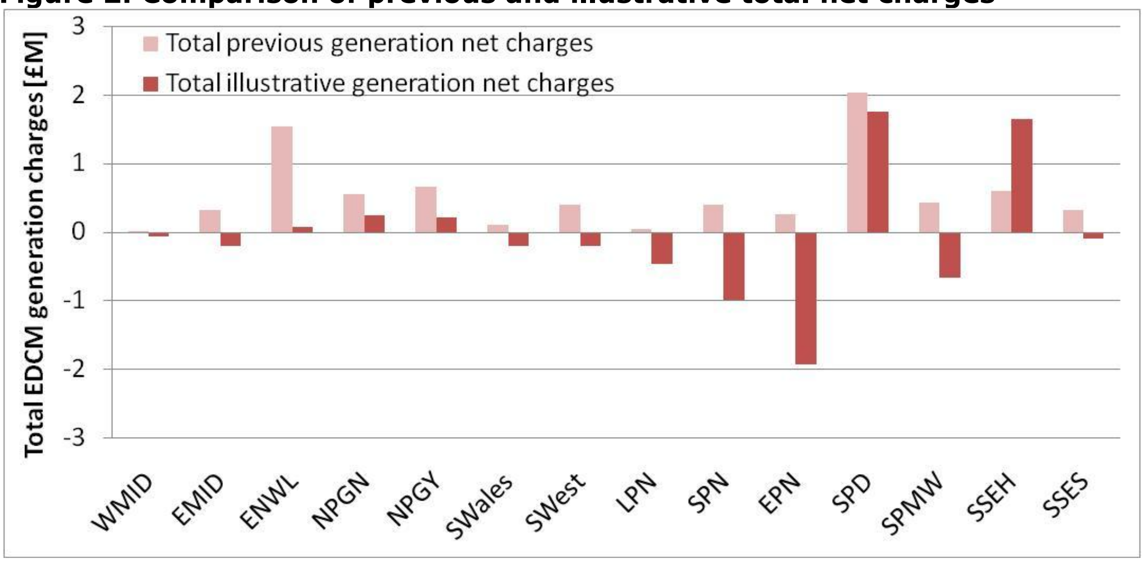
1.19. Figure 1 shows the illustrative charges and credits under the DNOs' proposed EDCM for export (scenario 3). The total fixed charges would be £2.8M, the total capacity charges would be £4.2M, and the total credits paid to generators would be £7.9M. Across the 14 DNOs, the net total would be a £0.9M credit. For five DNOs, there would be net total payments by EDCM generators, and for nine DNOs, there would be net total payments to EDCM generators. Although for each DNO there are ranges of charges and credits for different customers, as discussed later.

Figure 1: Total illustrative charges and credits



1.20. We can compare the net values with charges previously paid by generators. Figure 2 shows the total charges for higher voltage generation customers for each DNO, both under the existing methodologies and under the proposed EDCM for export (under scenario 3). At present, some DNOs do pay credits to some of these generators, but the totals for each DNO tend to be net charges. Across all of the DNOs, the total net charges would change from a £7.6M net charge to a £0.9M net credit.

Figure 2: Comparison of previous and illustrative total net charges

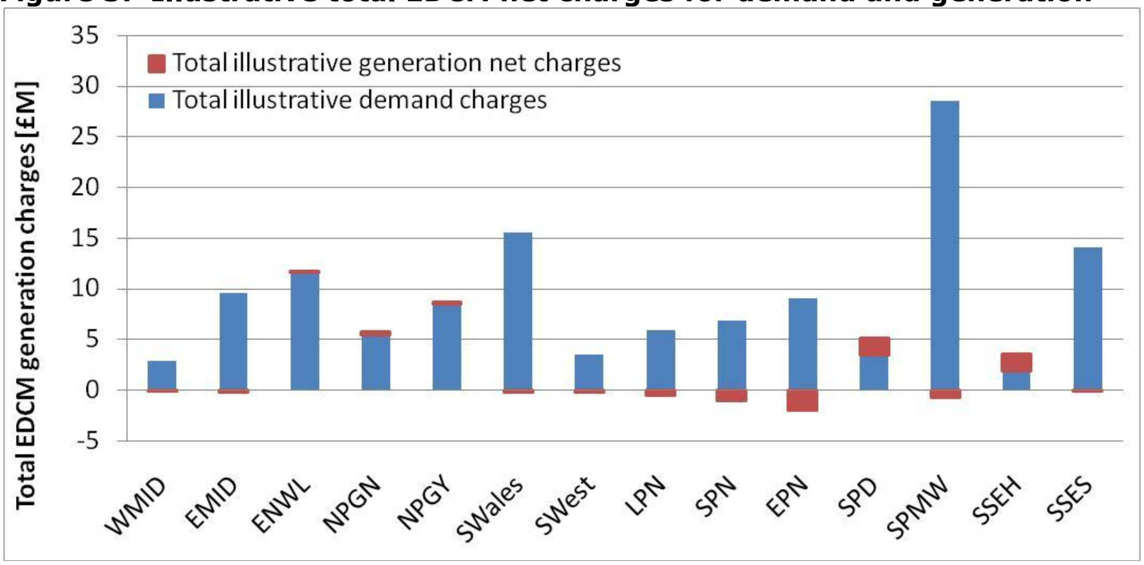


1.21. This comparison is for the total net charges for each DNO, but the figures are for different numbers of connections; i.e. fewer are charged now than would be under the EDCM. At present, 180 post-2005 connections are charged under a methodology, i.e. have a "previous charge". Due to incomplete data, we have the previous charges for only 157 of these connections. Under scenario 3, the following would connections be charged; these are discussed in more detail later on.

- 365 connections would be charged
    - 227 post-2005 connections
        - 180 with previous charges (we can make comparisons for 157)
        - 47 new connections without previous charges
    - 138 pre-2005 connections
        - 81 with expired exemptions
        - 57 opted in
    - 185 would be charged DUoS charges for the first time
    - 157 have previous charges and that data is available to us
    - 23 have previous charges and that data is not available to us

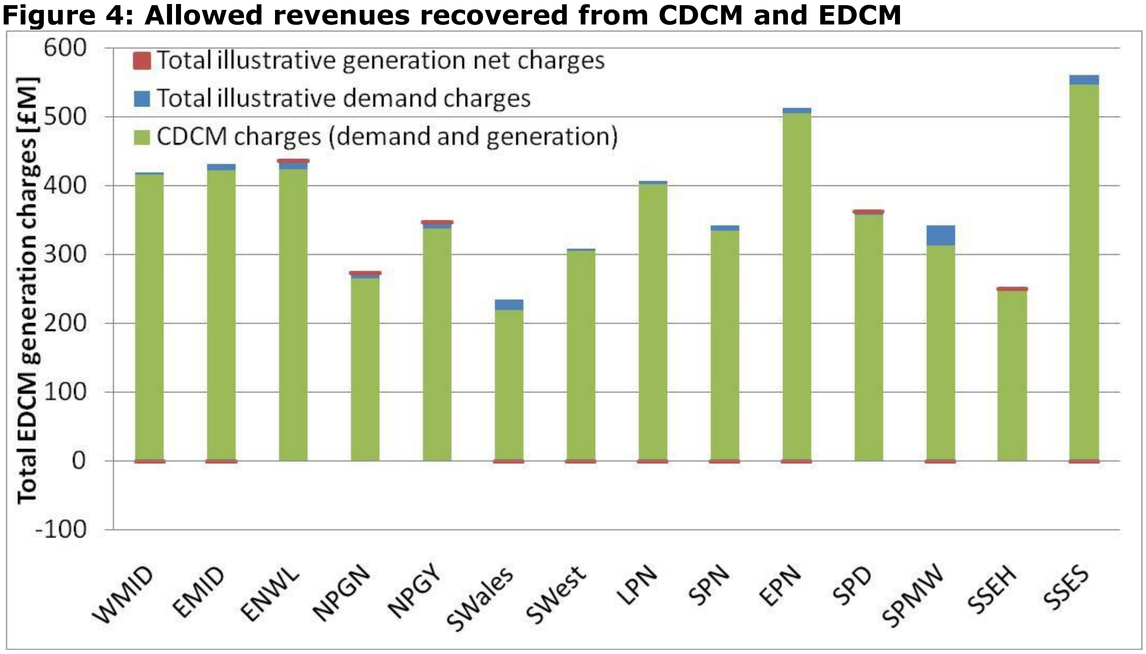
1.22. We can compare the illustrative net charges for EDCM generators with the illustrative charges for EDCM demand customers; data is shown in Figure 3. The total EDCM demand charges would be £127.1M, compared to which the net £0.9M credit for EDCM generators is very small (0.7 per cent), but there is variation between the DNOs.

Figure 3: Illustrative total EDCM net charges for demand and generation



1.23. We can also compare the EDCM export and import charges with the total CDCM charges; data is shown in Figure 4. EDCM charges (import and export) form a very small part of the DNOs' allowed revenues; the illustrative values would give an average of 2.4 per cent across all of the DNOs, with a maximum of 8.2 per cent for one DNO. The illustrative EDCM export charges would give an average value of 0.02 per cent across all of the DNOs, with a maximum of 0.5 per cent for one DNO.

Figure 4: Allowed revenues recovered from CDCM and EDCM



Impact on sustainable development

1.24. The proposed EDCM for export helps to facilitate sustainable development and the move to a low carbon economy. It does this by incentivising generation customers to modify their behaviour to use assets more efficiently, which in turn helps to reduce losses. Reducing overall network investment also helps to minimise the environmental and landscape impact of the distribution network itself. The EDCM for export also helps by providing clear pricing signals for the connection of distributed generation. We believe that the sustainable development objectives can be achieved in the longer term more effectively if we have in place a methodology that provides consistent, cost-reflective signals to all generators.

Reducing losses

1.25. While the distribution network does not generally produce carbon emissions in and of itself, electrical losses involved in the distribution of electricity must still be replaced with additional generation. Carbon emissions increase where that generation is produced using non-renewable sources. Accordingly, measures to reduce losses will also help to reduce carbon emissions.

1.26. There are two types of losses, variable and fixed. Variable losses are those that relate to the electrical current flowing through the asset. These losses increase as current flow increases but in a non-linear relationship: the losses increase with the square of the current flowing through the asset. Fixed losses are those that are incurred when an asset (such as a transformer) is energised; these occur regardless of the amount of electricity passing through the asset.

1.27. The EDCM for export would encourage generators to locate in areas with high demand. This would reduce the distance over which power must be transported, which would reduce losses; and it would reduce the loading on assets, which would reduce the variable losses. Also, the EDCM for export would discourage generators from locating in areas where there is little capacity; this would reduce the fixed losses.

1.28. These signals provide a further benefit when they defer additional reinforcement of the network. By avoiding the installation of new assets, additional fixed losses are also avoided. We do recognise that the provision of new assets (i.e. additional capacity) can reduce variable losses, but that the EDCM for export would discourage this. This is to some extent mitigated by the fact that each new asset will produce additional fixed losses.

Impacts from distributed generation charging

1.29. There are potential benefits to the environment from the connection of additional generators onto the distribution network, particularly where it uses renewable sources. Broadly speaking, the shorter and simpler the electrical path is between an electricity generator and a customer, the lower the losses are, both fixed and variable. Where that generation is renewable, there is an additional benefit to the reduction of carbon emissions.

1.30. For non-intermittent generation, the EDCM for export would provide credits where generation is most likely to offset demand in that area and reduce the need for reinforcement. For all generators, charges are levied when the level of generation will not offset demand but instead trigger reinforcement of the network. These pricing signals thus help to reduce losses by incentivising generators to connect and/or increase output in the former areas and avoid the latter. This helps to reduce the overall distance that electricity has to travel between generation and demand and therefore the amount of distribution losses.

1.31. We note that some intermittent generation (which typically uses renewable sources) would be charged for use of system for the first time. Some of them would receive a net credit, but some would receive a net charge. However, the magnitude of the charges is relatively small, and we have not been presented with evidence that the EDCM for export will have a material effect on the viability of renewable generators (either existing or new generators).

1.32. We also note, as discussed in Issue 1 of Chapter 2, that, while intermittent generators will be charged, it might not be appropriate for them to receive credits until the approach in the proposed EDCM for export can be reconciled with that in Engineering Recommendation P 2/6. If they can be reconciled, then we believe that this will encourage the connection of more intermittent generation. In these circumstances, there would be a further benefit for sustainable development. Further analysis on this can be found below.

Impact on competition

1.33. A common charging methodology facilitates competition in the electricity supply market. By replacing seven separate methodologies, it means that suppliers have greater certainty and understanding of the way in which charges are calculated. This removes a barrier to entry for suppliers competing across GB, and for new entrants.

1.34. A common and cost reflective charging methodology facilitates competition between generators in the electricity generation market. This ensures that generators across all DNOs are charged on the same basis and therefore receive equivalent pricing signals.

1.35. A common charging methodology aids competition between network companies. As for suppliers, it allows for LDNOs to have greater certainty and understanding about the calculation of charges. Also, the proposed methodology includes charging arrangements for LDNOs which aim to ensure a reasonable margin. This is driven both by ensuring cost reflective charges and that the margins given to LDNOs by the DNO are also reflective of the costs that the DNO avoids when an LDNO serves end users.

Impacts on health and safety

1.36. We have not identified any impacts on health and safety from this proposal.

Risks and unintended consequences

1.37. Any errors in the operation of the EDCM model or the input data may produce charges that are different from those intended. Subject to our approval of the EDCM for export, we expect the DNOs to thoroughly check both the operation of the model and all input data to ensure that it produces accurate charges for all customers.

1.38. More broadly, external changes, such as developments in the distribution network may mean that the EDCM for export no longer continues to meet all of the Relevant Objectives over time and will need to be reviewed.

1.39. We note that SLC 13.2 requires the DNOs to review the charging methodology at least once a year to ensure that it continues to meet the Relevant Objectives. It also requires them to make modifications as necessary to better achieve these objectives. These reviews should address the possible risks and unintended consequences outlined above.

Impacts on EDCM import (demand) customers

1.40. Introducing the EDCM for export could have some impact upon the charges for EDCM import customers, but these are expected to be small.

1.41. An increase (or decrease) in net revenue from generators would affect the target revenue to be recovered from EDCM and CDCM demand customers. This affects the revenue to be recovered through demand scaling, which in turn affects EDCM import charges. However, given the small size of the EDCM export revenue pot compared to the overall revenues for each DNO, this effect is expected to be relatively small (usually less than a few percentage points).

1.42. The introduction of the EDCM for export might require the DNOs to make slight alterations to the input data in the EDCM for import. For example, the way in which DNOs split sole use assets of mixed sites between import and export might change, and this can affect import charges, but we expect this to be more of a reallocation across tariffs rather than a change overall.

1.43. Finally, we note that the input data for all of the charging methodologies vary from year to year. Therefore, the EDCM import charges will probably change when the EDCM for export is introduced for reasons that are not related to that introduction. We encourage the DNOs to continue to explain to their customers the reasons for any changes to DUoS charges; and customers should contact their DNOs if they require further information.

Impacts on EDCM export (generation) customers

1.44. As noted above, there are 608 higher voltage generation customers, with 614 generation connections between them. Figure 5 shows the breakdown by DNO.

Figure 5: Numbers of higher voltage customers and generation connections

DNO	All customers	Demand customers	Generation connections
WMID	26	26	16
EMID	76	76	38
ENWL	81	81	32
NPGN	46	44	20
NPGY	109	109	35
SWales	69	68	41
SWest	75	72	55
LPN	32	32	4
SPN	48	48	17
EPN	105	105	48
SPD	78	77	50
SPMW	205	203	55
SSEH	195	183	168
SSES	96	95	35
Totals	**1241**	**1219**	**614**

1.45. There are different ways of classifying these customers and connections, depending upon the purpose. We can highlight some key figures that are of use for different parts of this assessment:

- 614 connections on 608 sites
  - 25 connections are "placeholders" with no agreed capacity
  - 362 connections are pre-2005
    - 81 have expired exemptions and so would be charged
    - 281 have non-expired exemption
      - 57 would get a net credit and so might opt-in in
      - 224 would get a net charge and so might opt-out
  - 227 connections are post-2005 and so would be charged
    - 47 new connections with no previous charge
    - 180 have previous charges
      - 157 can be compared against illustrative EDCM charges

- 365 connections would be liable for charges in scenario 3
  - 138 pre-2005 connections
    - 81 with expired exemptions
    - 57 with non-expired exemptions that might opt in
  - 227 post-2005 connections

1.46. The following sections set out analysis of the impacts on various groups of generators. Our analysis was conducted on the basis on export connections. For the six sites that have two export connections, we sought to separate out the impacts.

1.47. Some of the results set out below show large values for parameters such as annual charge or percentage changes. There are examples where further analysis shows that a large value is not as significant as it might seem. What matters is the combination of factors. For example, a generator might face a large charge, but that might be small compared to its export capacity. Or a generator with a previous charge might face a large percentage increase in its charges, but that could be a small increase in absolute terms depending upon the size of its previous charge. For reasons of commercial confidentiality, it is not possible to publish sufficiently detailed data to illustrate the exact overall impact on each individual generation customer. Customers should contact their DNOs in order to discuss their charges in more detail. We would be happy to meet with customers to discuss any issues.

Components of the net charges

1.48. As noted above, it can be expected that 365 generators would be charged under the EDCM for export under scenario 3. Before looking at the illustrative charges and credits, it is instructive to consider the key components: the fixed charges, the capacity charges, and the credits.

1.49. Figure 6 shows the average values for the fixed charges per unit of MEAV for the customers of each of the DNOs. Fixed charges are generally higher in more remote areas where sole-use assets tend to be longer and where the frequency and cost of maintenance are higher. This is illustrated in Figure 6 in which the data has been normalised for the MEAV of the sole-use assets.

1.50. Similarly, Figure 7 shows the export capacity rates used by each DNO. Capacity charges are generally higher in more remote areas where the shared network is larger and where the frequency and cost of maintenance are higher. This is illustrated by the export capacity rates in Figure 7.

1.51. Finally, Figure 8 shows the average values for the credits paid to the customers of each of the DNOs. Credits tend to be lower in areas where there is a relative surplus of generation compared to demand. This is illustrated in Figure 8, in which the data has been normalised for the capacity of the generators.

1.52. We have analysed the data that sits behind these graphs. This shows a correlation between the fixed charge and the MEAV of the sole-use assets, and also between the capacity charge and the capacity of the connection. These correlations are as expected and suggest that the methodology does produce cost-reflective charges. This data cannot be published because it could be interpreted so as to reveal confidential information about specific customers.

Figure 6: Average fixed charges per unit of MEAV

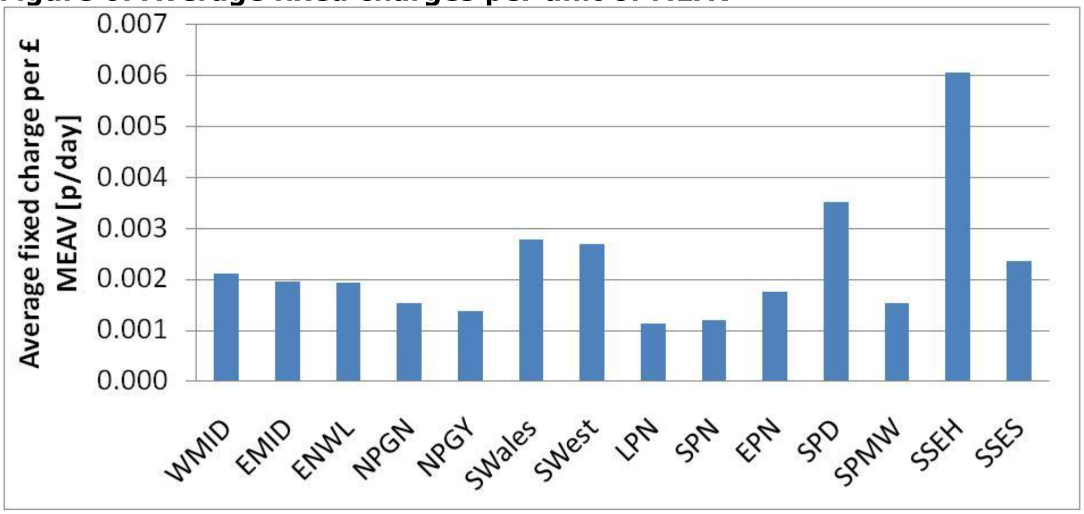


Figure 7: Export capacity rates

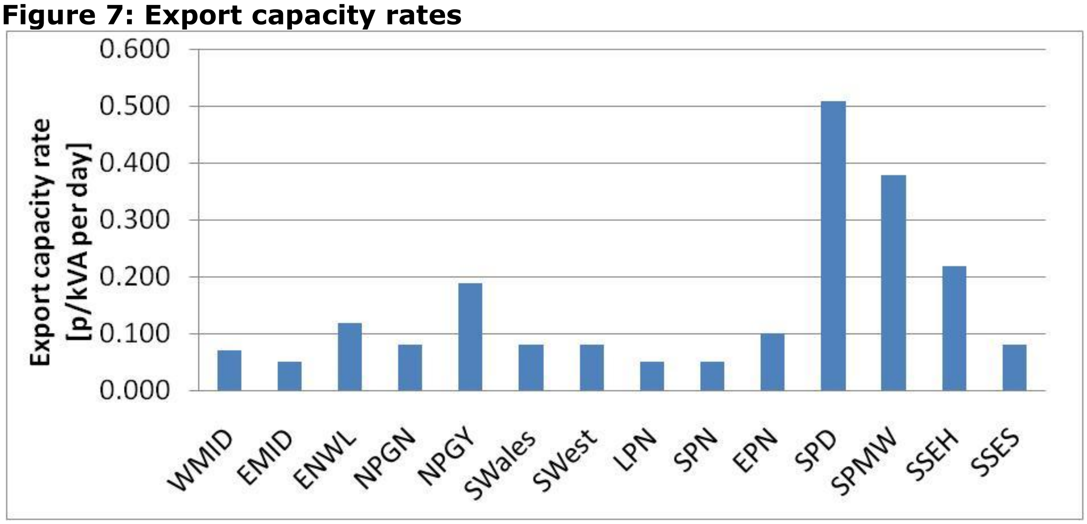
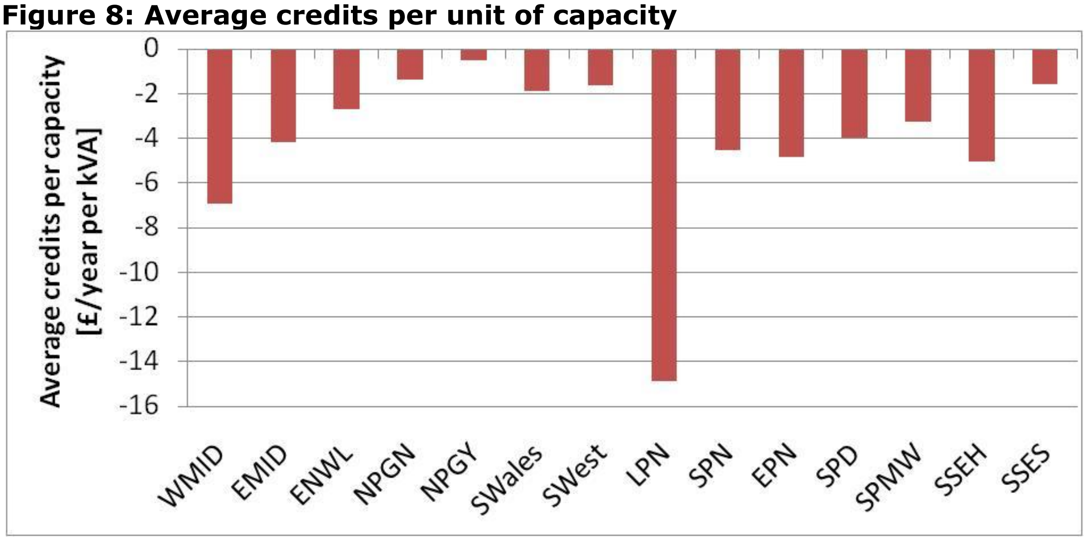


Figure 8: Average credits per unit of capacity



All connections that would be charged under the EDCM for export

1.53. Figures 9 and 10 show the illustrative data for the 365 export connections that would be charged under the EDCM for export in scenario 3. The most useful basis for comparison are the charges for a year, divided by the capacity (£/yr per kVA), as shown in Figure 9; this is not the capacity charge (£/kVA).

Figure 9: Distribution of net charges for a year

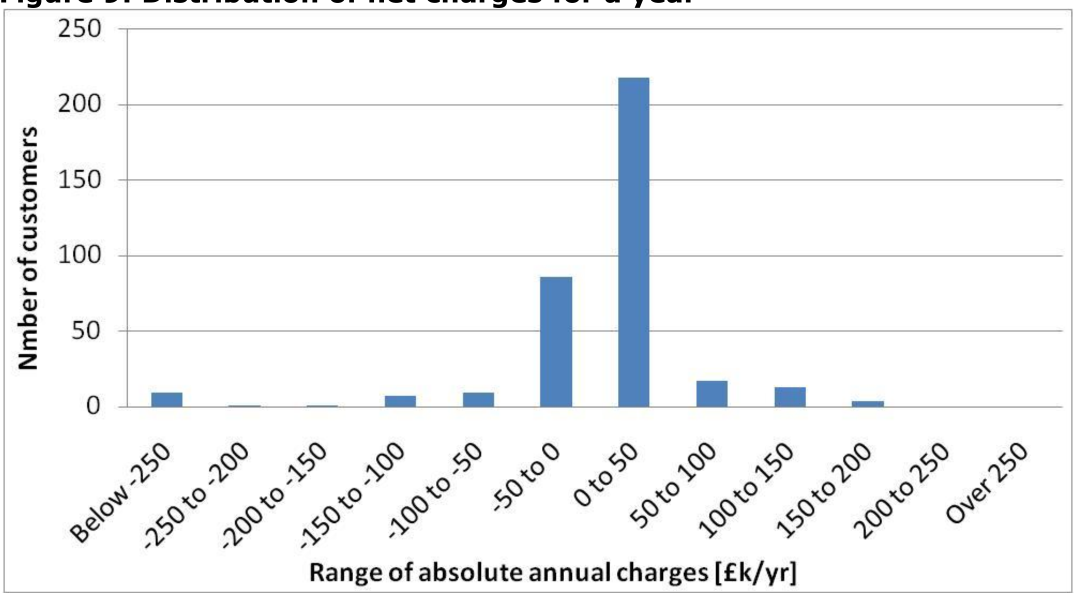
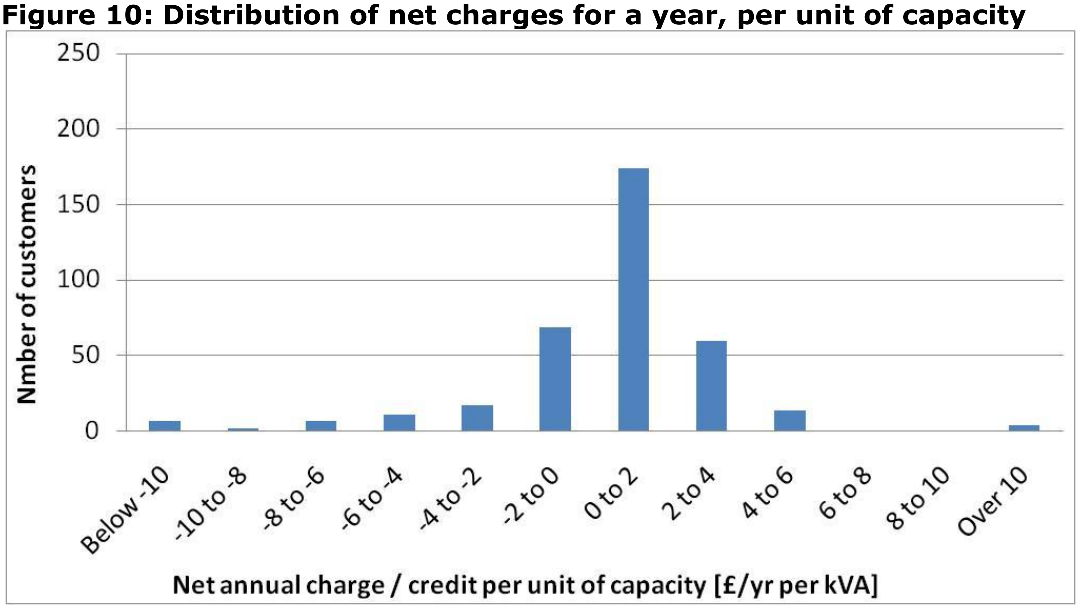


Figure 10: Distribution of net charges for a year, per unit of capacity



1.54. These charts show that 69 per cent of EDCM connections would have a net charge, and 31 per cent would receive a net credit. They also show that there would be a fairly narrow distribution: 48 per cent would pay £0 to 2/yr per kVA; and 19 per cent would receive £0 to -2/yr per kVA.

1.55. Of the remaining 33 per cent, we note that the net annual charges per unit of capacity would be above the narrow range for 21 per cent of EDCM generators. Most of these connections have higher value sole-use assets, which results in higher fixed charges. Almost all are located in more remote areas where the costs of the shared network are higher, so they also have higher capacity charges. In addition, being in more remote areas with a relative surplus of generation, most of them do not receive credits. Of the 1 per cent (4 connections) that would have net annual charges per unit of capacity of above £10/yr per kVA, the maximum would pay just over £11/yr per kVA. All four are small capacity connections located in the area of SHEPD, and their fixed charges make up over 90 per cent of their net charges. The high "unit costs" result from the costs of sole-use assets that serve small generation assets.

Connections with previous charge, but would have no EDCM export charge

1.56. We note that some connections with a previous charge would be likely to use an exemption to opt out of the EDCM for export. These are connections have a previous charge under the CDCM (where they receive credits), but would move to the EDCM for export as a result of the boundary change. They would receive a net charge under the EDCM for export, but are eligible for an exemption. We think that this will affect five generators, with the average removed credit being £38k, and the maximum being £61k.

Connections with previous charge, and would have an EDCM export charge

1.57. Some connections that would fall under the EDCM for export have previous DUoS charges. Some are charged under the CDCM, and would move to the EDCM when the boundary change comes into effect. Some are charged under the DNOs' existing EHV methodologies that the EDCM for export would replace. We are particularly interested in the impacts on those post-2005 connections that have a previous charge and would be charged under the EDCM for export, as they allow us to compare charges under the existing and proposed methodologies.

1.58. Figures 11, 12 and 13 show the illustrative data for the 157 post-2005 connections that have previous charges, that would be charged under the EDCM for export in scenario 3, and for which we can make comparisons with previous charges. These three Figures all show that 89 per cent (140) of connections would have a reduction in charges, and that 11 per cent (17) of connections would have an increase in charges. However, it is important to consider that these changes can occur in one of several different ways, and an increase does not necessarily mean an increase in charges. For example, if a net credit became smaller, the customer would still be benefitting from payments and would not be paying charges, but it would be classed as an increase in net charges.

Figure 11: Change in net annual charges

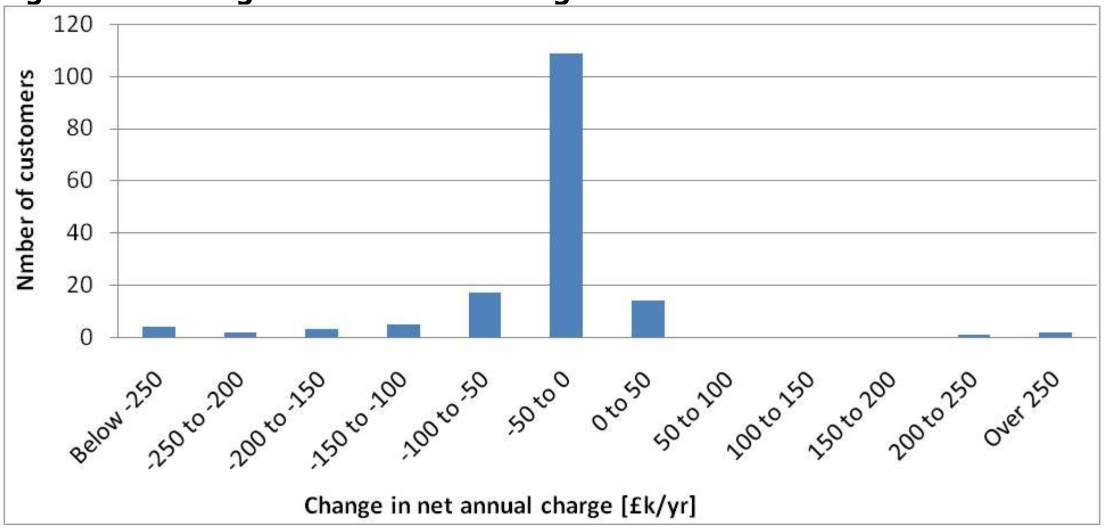


Figure 12: Change in net annual charges per unit of capacity

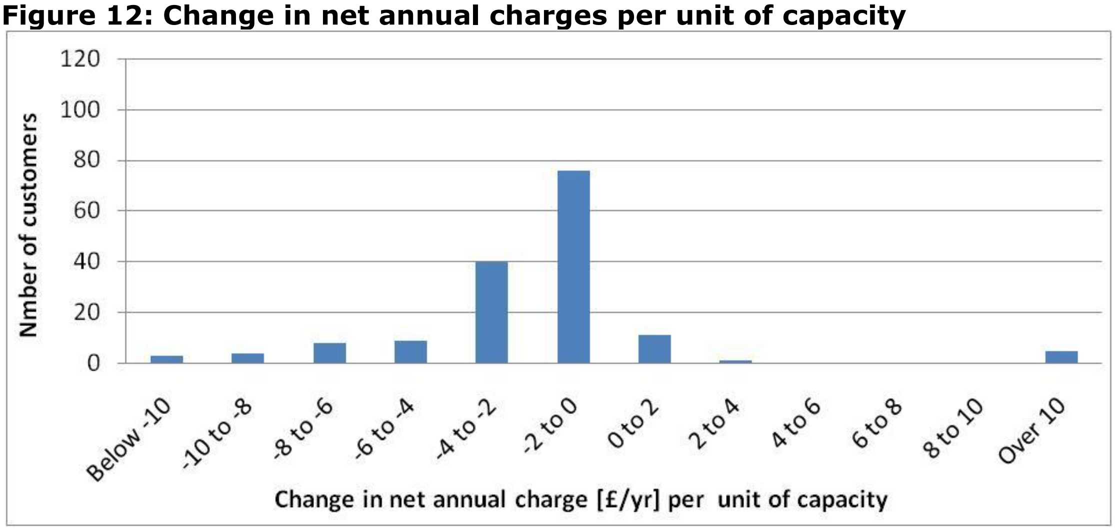
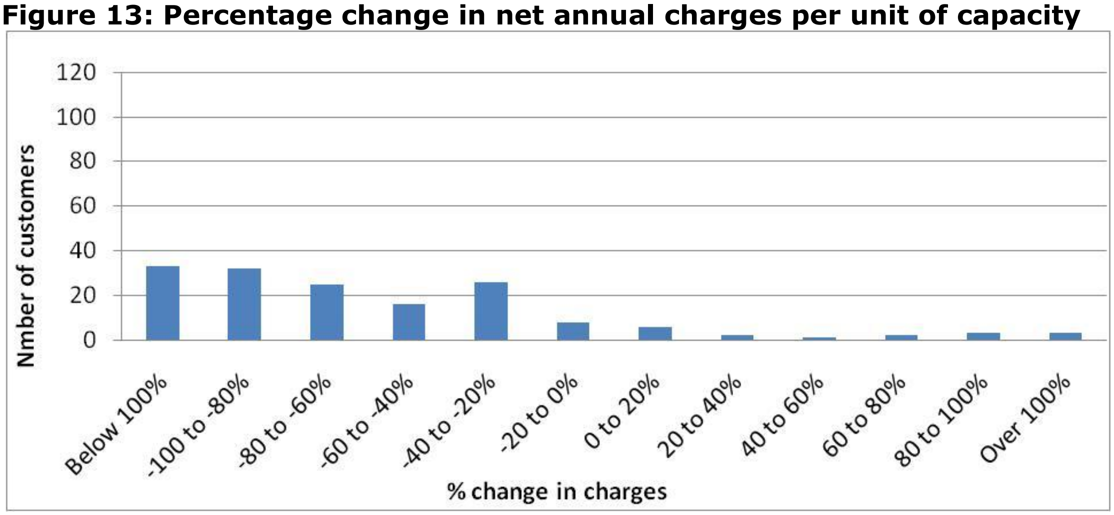


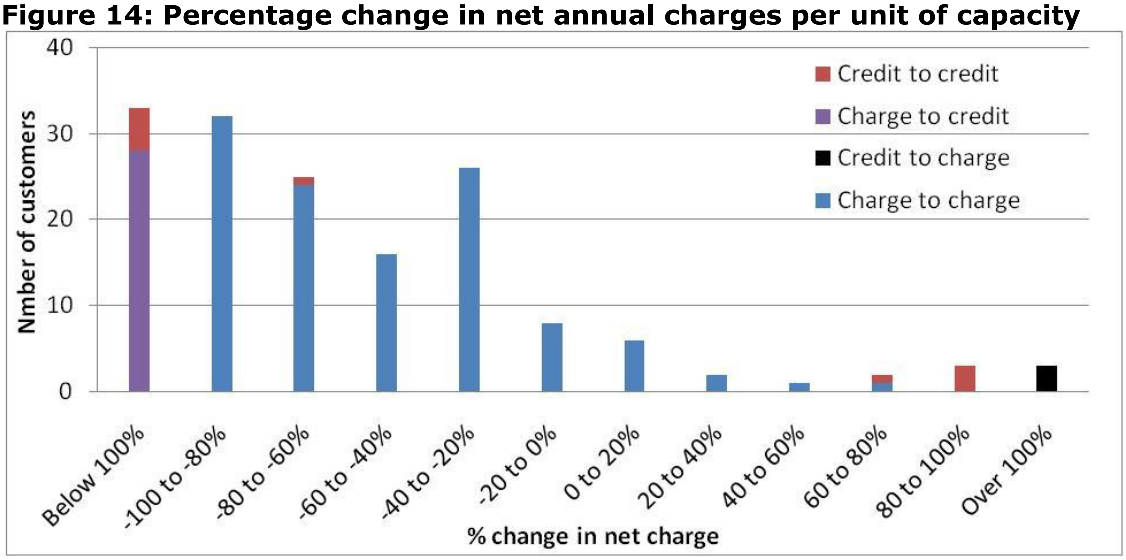
Figure 13: Percentage change in net annual charges per unit of capacity



1.59. Taking these points into account, we can redraw Figure 13 as Figure 14 that breaks down the data into the following four groups. The examples show what would happen if a £1 net charge or net credit changed different amounts.

- Net charge previously becomes a net charge in the EDCM for export
    - +£1 net charge becomes +£1.50 net charge: 50 per cent increase
    - +£1 net charge becomes +£0.50 net charge: 50 per cent decrease
- Net charge previously becomes a net credit in the EDCM for export
    - +£1 net charge becomes -£0.50 net credit: 120 per cent decrease
- Net credit previously becomes a net credit in the EDCM for export
    - -£1 net credit becomes -£0.50 net credit: 50 per cent increase
    - -£1 net credit becomes -£1.50 net credit: 50 per cent decrease
- Net credit previously becomes a charge in the EDCM for export
    - -£1 net credit becomes +£0.10 net charge: 110 per cent increase

Figure 14: Percentage change in net annual charges per unit of capacity



1.60. The financial implications for a generator depend upon whether the value of the change in its net charge is positive or a negative, and also upon which of these four groups it is in. Taking these points into account:

- 106 would get a reduced net charge; 10 would get an increased net charge
- 28 would get a net credit in place of a net charge
- 6 would get an increased net credit; 4 would get a reduced net credit
- 3 would get a net charge in place of a net credit

1.61. So, although Figure 13 suggests that 17 connections would have an increase in charges, this is actually a reduced credit for four of them. 10 connections would see an increase in net charges, and for eight of these it would be less than 20 per cent. Three connections would have a net credit replaced by a net charge: for all of them the net charge is a few thousand pounds per year; for two of them the magnitude of the net charge would be much smaller than the magnitude of the net credit that it replaced.

Connections with no previous charge

1.62. If the EDCM for export is introduced, we think that 185 connections would be charged for the first time, according to the data provided by the DNOs:

- 47 post-2005 connections
- 81 pre-2005 connections whose exemptions will have expired
- 57 pre-2005 exempt connections that would be likely to opt in

1.63. Figures 15 and 16 show the illustrative net charges and the net charges per unit of capacity for these connections under scenario 3: 46 (98 per cent) post-2005 connections would see net charges; and 69 (85 per cent) of pre-2005 connections with expired exemptions would see net charges. The 57 pre-2005 connections with non-expired exemptions are those that would opt in in order to get net credits.

Figure 15: Net charge for a year for customers not previously charged

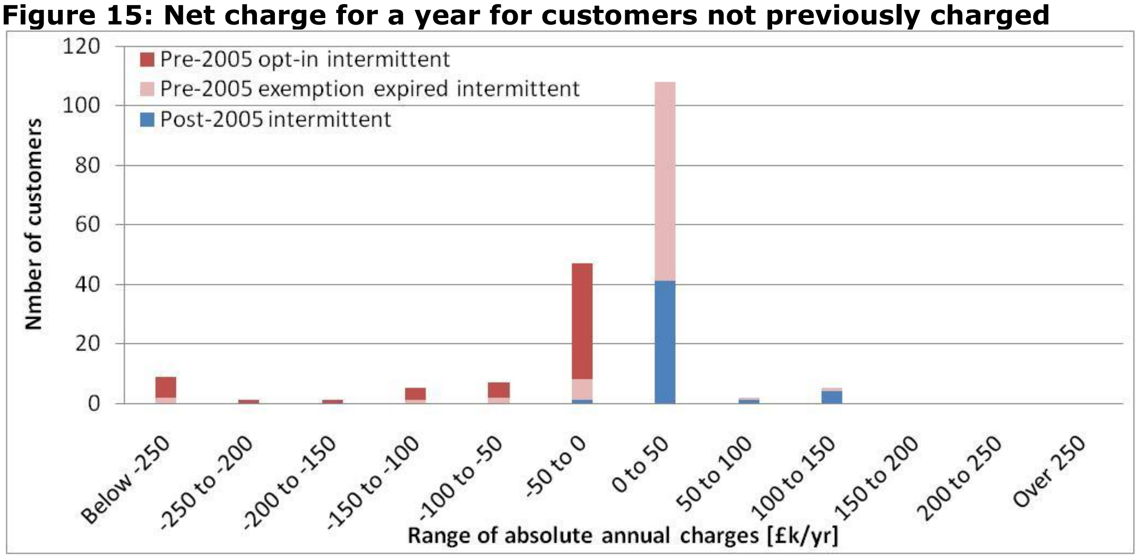
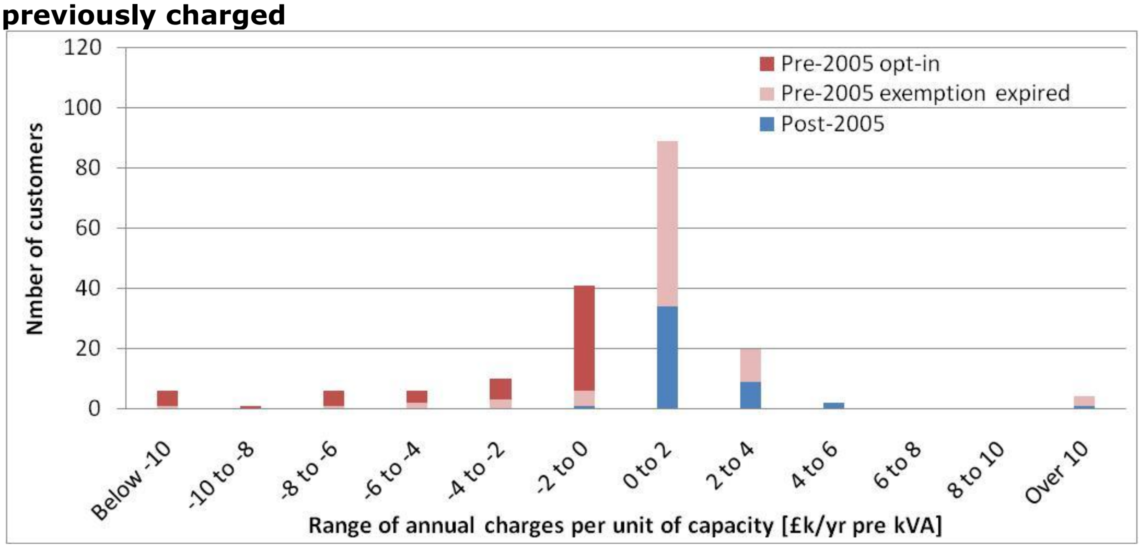


Figure 16: Net charge per unit of capacity for a year for customers not previously charged



1.64. Eventually all exemptions will expire and all pre-2005 higher voltage export connections will be subject to the EDCM for export. The DNOs provided data for this situation as scenario 2. However, by the time that all higher voltage export connections are subject to the EDCM for export, the input data will have changed such that scenario 2 results would not be valid. Therefore, we have not presented analysis of that situation.

Intermittent generators

1.65. In most respects, intermittent generators are treated in the proposed methodology exactly the same as non-intermittent generators. However, under the DNOs proposals, they would receive only partial credits; this is included in the proposed methodology, and features in the results presented above. However, as discussed above, there is the possibility that intermittent generators would not receive these partial credits. This could be the case permanently, or until such time as issues around the EDCM for export and Engineering Recommendation P 2/6 are resolved. We have considered the impact of this upon intermittent generators. We have not created a new scenario, but we have the following observations that indicate the impact.

1.66. As discussed below, the credits that would be paid to intermittent generators total £881k. If this was not paid to them, then demand customers would pay less by that amount; this is a very small saving per customer. The credits do not directly affect the charges within the EDCM for export; the fixed charges and capacity charges for all generation customers (intermittent and non-intermittent) would be unaffected. There could be an indirect effect on capacity charges, as discussed later.

1.67. The only direct effect would be upon the net charge seen by the intermittent generators themselves. It is helpful to consider intermittent generators in groups:

- 376 intermittent generation connections in total:
    - 136 pre-2005 eligible for exemption (could opt in)
    - 52 pre-2005 with exemptions expired (would be charged)
    - 188 post-2005 (would be charged)

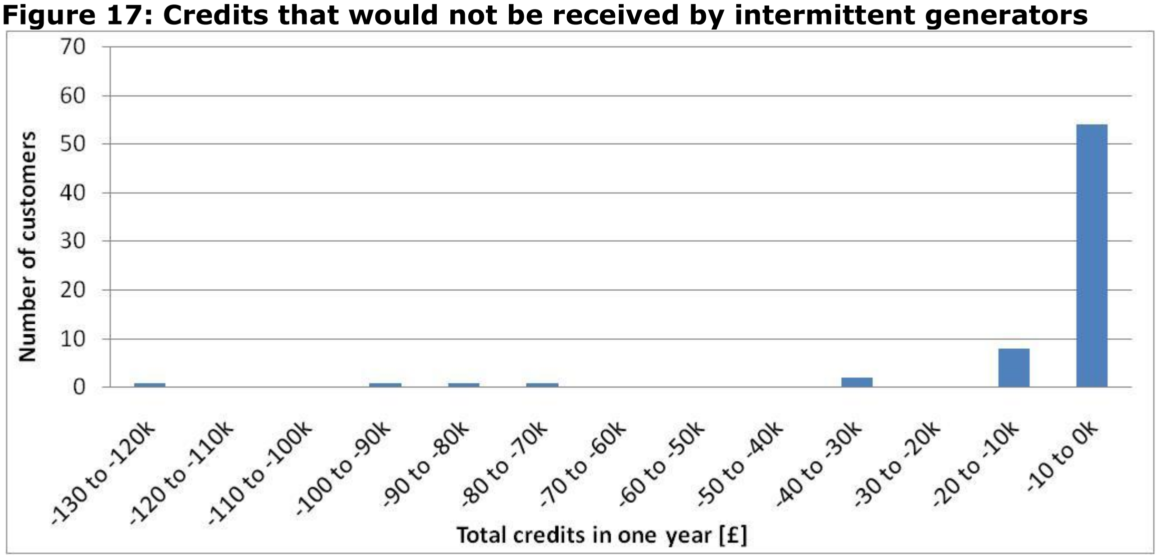
- 80 out of the 376 would receive a credit:
    - 12 out of 136 pre-2005 eligible for exemption (could opt in)
    - 6 out of 52 pre-2005 with exemptions expired (would be charged)
    - 62 out of 188 post-2005 (would be charged)

- 46 out of the 80 would receive a net credit:
    - 12 out of 12 pre-2005 eligible for exemption (could opt in)
    - 3 out of 6 pre-2005 with exemptions expired (would be charged)
    - 30 out of 62 post-2005 (would be charged)

1.68. So, whatever the position with credits, 68 intermittent generators (62 post-2005 and six pre-2005 exemption expired) would definitely be subject to the EDCM for export. If credits were available for intermittent generators, then it would be likely that a further 12 would opt in expecting net credits. These figures are included in the results presented in the previous sections. We estimate that the total credits for intermittent generators would amount to £881k in scenario 3: c.£490k between 62 post-2005 generators; c.£259k between six pre-2005 generators whose exemptions have expired; and c.£132k between 12 pre-2005 generators whose exemptions have not expired and that would receive a net credit.

1.69. If credits were not available for intermittent generators, 68 of them would still be charged under the EDCM for export, without credits to offset their charges (whether fully or partially). We estimate that the total amount of credits that these 68 customers would not receive would be £749k. The maximum payable for any customer would be £126k, and the average per customer would be £11k. The distribution is shown in Figure 17.

Figure 17: Credits that would not be received by intermittent generators



1.70. It is likely that the 12 pre-2005 intermittent generators that were eligible for exemption would opt out; the total credit that they would now not receive would be £132k. The maximum for any customer would be £40k, and the average per customer would be £11k.

1.71. We can summarise these results by looking at the distributions of net charges. Figure 18 shows the distribution of net charges for intermittent generators that would be eligible for credits under the DNOs' proposals. Figure 19 shows the distribution of charges for the same connections if credits were not available for them; it does not include pre-2005 generators that are eligible for an exemption because they would presumably not opt in if they faced a net charge. These charts illustrate how the distribution of net charges for these connections would shift if super-red credits were not available for intermittent generators.

Figure 18: Net charges for intermittent generators that would receive credits under DNOs' proposals

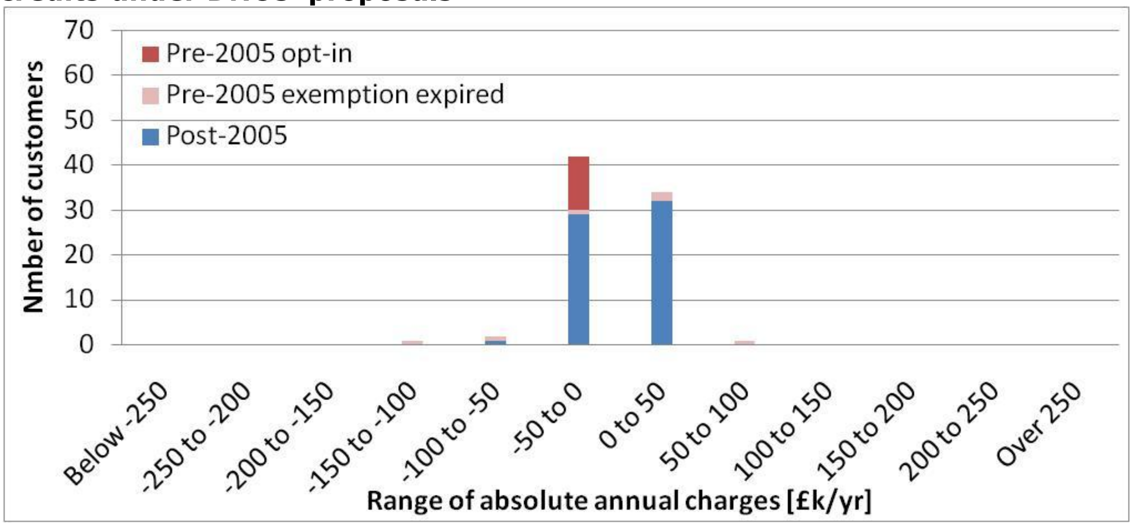
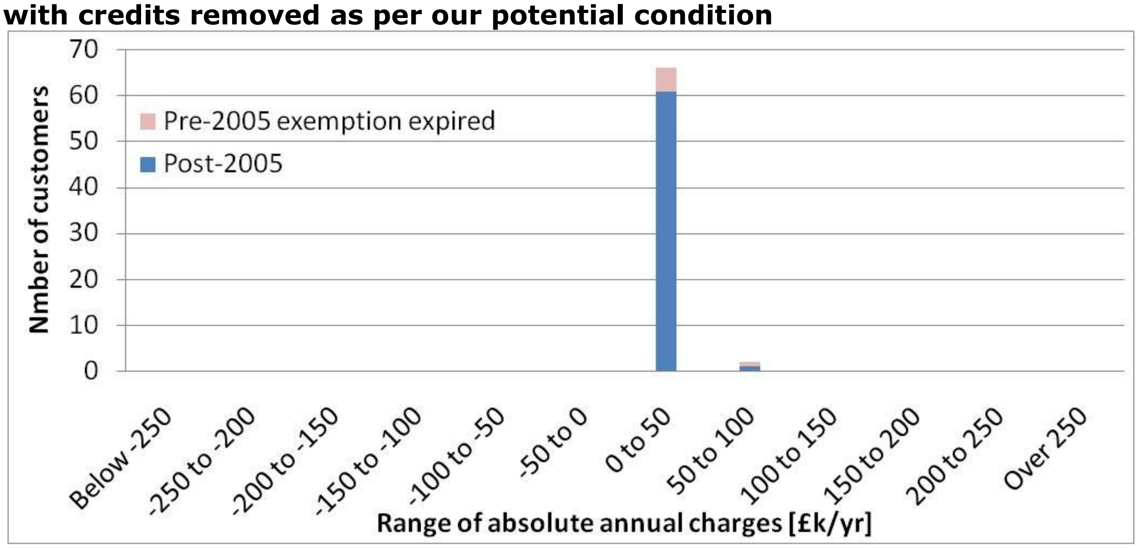


Figure 19: Net charges for intermittent generators shown in Figure 18, but with credits removed as per our potential condition



1.72. Finally, as noted above, preventing intermittent generators from receiving super-red credits could have an indirect effect on the charges of other generators. If the three pre-2005 intermittent generators whose exemptions had not expired and who would otherwise have expected a net credit, decided to opt-out, then the revenue pot would shared amongst fewer customers, and capacity charges would be higher for the generators that remained in the EDCM for export. However, given the small number of generators in that situation, we anticipate that this impact would be minimal.

Appendix 2 - Consultation Response and Questions

2.1 Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

2.2 We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

2.3 Responses should be received by **Tuesday 2 October 2012** and should be sent to:

Simon Cran-McGreehin
Networks Policy
9 Millbank
London
SW1P 4LA

020 7901 7440

Simon.Cran-McGreehin@Ofgem.gov.uk

2.4 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.

2.5 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.

2.6 Next steps: Having considered the responses to this consultation, Ofgem intends to reach a decision on whether to approve the DNOs' proposed EDCM for export, and to publish that decision in October 2012. Any questions on this document should, in the first instance, be directed to Simon Cran-McGreehin (details given above).

CHAPTER: One

Question 1: Have the options available to pre-2005 generators been clearly explained to those generators?

Question 2: What information (or guidance) about the EDCM would be of use to industry participants, and what do DNOs and generation customers think could be provided?

CHAPTER: Two

Question 1: Do you think that the proposed methodology includes the relevant issues, and has not omitted any relevant issues?

Question 2: Do you agree with our understanding that the interactions between super-red credits for intermittent generators and Engineering Recommendation P 2/6 could result in demand customers paying for credits when no network benefit is recognised under the planning standard?

Question 3: Is the treatment of sole-use asset costs appropriate?

Question 4: Is the calculation of the revenue pot appropriate, in particular the approach to the DPCR4 contribution, and proposed figure for the O&M rate?

Question 5: Is the approach to allocation of the revenue pot appropriate?

Question 6: Do you have any views on the calculation of LDNO charges through the extended “Method M” for CDCM-like customers, and through the separate methodology for EDCM-like customers?

Question 7: Do you have any other comments about the issues that we have noted, or about any other points?

Question 8: Is it appropriate for us to approve the methodology?

Question 9: Is it appropriate for us to place the potential condition that we have suggested, and are there any other conditions that respondents feel would help to better meet the Relevant Objectives?

Question 10: Do you think that we have identified the important impacts in our Impact Assessment?

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.

C

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.

D

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.

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

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

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.

H

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 (e.g. 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

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

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-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.

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

4.1 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?

4.2 Please send your comments to:

Andrew MacFaul
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE

Andrew.MacFaul@ofgem.gov.uk