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Extra High Voltage Distribution Charging Methodology: Impact Assessment

Consultation - supplementary annex

Publication date: 20 May 2011

Response deadline: 4 July 2011

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Overview:

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

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

This Impact Assessment provides a detailed overview of the impacts on consumers, competition and sustainable development. It also discusses options around the Authority's approval of the EDCM.

Context

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

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

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

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

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Key issues and objectives

1.1. The existing regulatory charging regime for higher voltage customers in GB comprises seven different methodologies. These calculate charges in a variety of ways and we do not think they produce charges that encourage the most efficient use of the network. In some cases, the methodologies have not been substantially updated for a number of years. The lack of commonality also makes it costly for suppliers and Licensed Distribution Network Operators (LDNOs) to operate across the fourteen distribution network areas.

1.2. With an estimated £2.2 billion in network reinforcement costs (of which £1.6 billion is at the Extra High Voltage (EHV) level) over the DPCR5 period[1] and developments such as the increasing prevalence of distributed generation, it is important that charging methodologies reflect developments in the distribution business and promote efficient behaviour.

1.3. The proposed EHV Distribution Charging Methodology (EDCM) aims to address these issues by introducing a common methodology across all Distribution Network Operator (DNO) areas. Specifically, the aims of the EDCM are to:

- drive efficient investment and use of existing network assets by setting prices that encourage customers to locate where there is spare capacity
- encourage competition from LDNOs and competition between suppliers (as we expect the introduction of a common method GB-wide to reduce barriers to entry)
- support sustainable development through the connection of more distributed generation in areas of high demand

1.4. The DNOs have submitted the methodology under Standard Licence Condition (SLC) 50A. This condition outlined four relevant objectives that the EDCM must comply with. These conditions are in line with the Authority's principal objectives and duties of protecting the interests of current and future consumers through regulating the electricity networks and promoting competition where appropriate. It is also relevant to our security of supply objective in terms of ensuring adequate investment in the network and contributing to the drive to curb climate change and encourage sustainable development.

[1] The fifth Distribution Price Control Review period runs from 1 April 2010 to 31 March 2015.

Options

1.5. Following the implementation of the licence requirement on DNOs to submit a common methodology at higher voltage levels by 1 April 2011, the licence specifies that the Authority must now decide whether to approve the DNOs' proposals for implementation, approve them subject to conditions or not approve them. These represent the three options that we describe below.

1.6. Options to mitigate the impact from the change in charges are described in this Impact Assessment as discussed in Chapter 2. We note that phasing in the change in charges or delaying implementation could require a change to the licence.

Option 1 – approve the methodology as submitted by the DNOs

1.7. This option would involve us approving the EDCM that the DNOs submitted on 1 April 2011, in the same form that it was submitted without any changes.

Option 2 – approve the methodology with conditions

1.8. Under this option, we would approve the methodology as it was submitted by the DNOs, subject to a number of conditions on the DNOs. SLC 50A.21-22 sets out the process by which we can place conditions on the DNOs.

1.9. The potential conditions we have outlined in the main consultation document are:

1. Consideration of spare capacity in the calculation of network use factors (NUFs) (to further consider the issue and either provide evidence to us that this is not material or come up with a better method). (paragraph 2.25)
2. Credits to intermittent generation (to give them credits). (paragraph 2.27) in main document)
3. Generation revenue target (to correct the incomplete use of the sole use scaling factor). (paragraph 2.29)
4. Application of a discount on capacity-based charges to LDNOs (demand charge related to 20 per cent of the residual and generation charge related to scaling). (paragraph 2.31)
5. LRIC branch capping (to correct the calculation). (paragraph 2.33)

1.10. The impact of each of these against Option 1, ie approving without conditions, is assessed in the *Impact on EDCM demand customers* and *Impact on EDCM generators* below from paragraphs 1.47 and 1.66 respectively.

1.11. Option 2 also extends to other conditions that we might make, following feedback through the current consultation process. Accordingly, we welcome stakeholder suggestions about any conditions they think we should place on the DNOs. Under SLC 50A.22, we are required to give the DNOs 28 days notice of any conditions we intend to make.

Option 3 – non-approval of methodology

1.12. This option would involve rejecting the DNOs' proposed EDCM 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.

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

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

1.15. This Impact Assessment uses Option 3 as the baseline to assess the impact of EDCM charges, ie a continuation of the DNOs' current individual charging methodologies.

Impact on consumers

1.16. Ofgem generally considers consumers as domestic customers. These customers are covered by the CDCM which calculates charges for customers connected at the lower voltage levels. The EDCM produces charges for large business and industrial users connected to higher voltage levels. Therefore, for the purposes of this IA consumers also include large businesses and industrial users.

Impact on charges

1.17. Despite not being subject to EDCM charges, the introduction of the EDCM will have an impact on charges for domestic consumers. This is because the total revenue to be recovered from lower voltage customers (through the CDCM) is the DNO's allowed revenue minus the revenue recovered from higher voltage customers. For each DNO the revenue recovered from higher voltage customers through the EDCM is different from the revenue recovered from the same customers through existing methodologies. This difference will affect charges for lower voltage customers.

1.18. The EDCM determines the share of allowed revenue to be recovered from EDCM customers, with the remainder recovered from CDCM customers.

1.19. Across DNOs, the total transfer from EDCM to CDCM customers would be £32 million for the 2011-12 charging year. This equates to £0.37 per domestic customer per year. DNO specific changes in charges for domestic customers can be seen in the following table.

Table 1.1 Impact of the EDCM on CDCM domestic customers

DNO	Impact on DUoS charge (£)	Impact on DUoS charge (%)	Impact on final bill (%)
WPD W Midlands	0.00	0.00%	0.00%
WPD E Midlands	-0.02	-0.03%	-0.01%
ENWL	0.33	0.38%	0.06%
CE NEDL	-0.41	-0.47%	-0.08%
CE YEDL	0.49	0.60%	0.10%
WPD S Wales	1.58	1.48%	0.25%
WPD S West	0.04	0.03%	0.01%
UKPN LPN	0.34	0.45%	0.08%
UKPN SEPN	1.25	1.62%	0.28%
UKPN EPN	0.13	0.18%	0.03%
SP Distribution	0.90	0.97%	0.17%
SP Manweb	0.63	0.57%	0.10%
SSE Hydro	0.32	0.21%	0.04%
SSE Southern	0.00	0.00%	0.00%
Average	**0.37**	**0.40%**	**0.07%**

Nb DUoS charges are assumed to represent 17 per cent of the final bill

Benefits from the EDCM

1.20. In the longer run, domestic customers are expected to share the benefits of a cost reflective EDCM.

1.21. The CDCM, implemented on 1 April 2010, aims to provide consumers with a number of benefits such as short and long term cost savings arising from a common, transparent and cost reflective methodology. The CDCM also helps to facilitate connection of distributed generation which typically use low carbon technologies. These benefits are discussed in Ofgem's September 2009 consultation document on the DNOs' CDCM proposals.[2]

1.22. The EDCM helps to further deliver these benefits by exposing higher voltage customers to a cost reflective charging methodology, with appropriate arrangements for generation and LDNOs.

1.23. These benefits are expected to deliver lower overall network costs resulting from a more efficient use of the network which, in the longer term is expected to feed into lower distribution charges for all customers.

1.24. Consumers also benefit from the stronger competition the EDCM enables and its support for sustainable development. A common and cost reflective methodology

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[2] DNO's proposals for a common methodology at lower voltages, available at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=502&refer=Networks/ElecDist/Policy/DistChrgs

lowers barriers to entry for LDNOs (who may be connected at higher voltages, but serve lower voltage customers) and suppliers. Sustainable development is supported by providing cost reflective prices for more distributed generation (which is often renewable) in areas of high demand and through more efficient use of the network resulting in lower losses.

Impact on competition

1.25. We expect the EDCM to encourage competition in the retail electricity market, as well as amongst generators and DNOs.

1.26. A common methodology aids competition in the electricity industry as it allows for greater certainty and understanding of the way in which charges are calculated. This particularly helps suppliers and LDNOs by reducing barriers to entry, as they are only required to deal with one, rather than seven separate methodologies.

1.27. The EDCM 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.

1.28. A common and cost reflective methodology should also facilitate competition between generators. This ensures that generators across all DNOs are charged on the same basis and therefore receive equivalent pricing signals.

Impact on sustainable development

1.29. The proposed EDCM helps to facilitate sustainable development and the move to a low carbon economy. It does this by incentivising customers to modify their behaviour to use assets more efficiently, which in turn helps to reduce losses. Reducing overall network investment also helps to minimise the environmental and landscape impact of the distribution network itself. The EDCM also helps by providing clear pricing signals for the connection of distributed generation (DG). We also recognise that introducing charging for DG that has not to date paid distribution use of system (DUoS) charges (some of which uses renewable sources) could have a negative impact on these goals.

Reducing losses

1.30. 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.

1.31. The EDCM provides pricing signals that encourage users to reduce consumption at times of peak demand (particularly for those customers located in congested parts of the network). This helps to reduce variable losses as they are highest when assets are being used at maximum capacity. 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.

1.32. Pricing signals are also given to customers to encourage them to connect where there is spare capacity and to avoid connecting in congested areas of the network. For those already operating in congested areas, signals are given to reduce peak consumption (as outlined in the above paragraph). These signals incentivise more even use of the network which also helps to reduce losses. This is because, for example, two identical assets operating at 50 per cent capacity will produce fewer losses than if one asset operates at 90 per cent and the other at 10 per cent.

1.33. These signals provide a further benefit when they defer additional reinforcement of the network. In addition to variable losses, fixed losses are also incurred when an asset (such as a transformer) is energised. These occur regardless of the amount of electricity passing through it. Thus, by avoiding the installation of new assets, additional fixed losses are also avoided.

1.34. We do recognise that the provision of new assets (ie additional capacity) can reduce variable losses (such that, in the above scenario each asset operates at 33 per cent of its capacity), but that the EDCM discourages this. This is to some extent mitigated by the fact that each new asset will produce additional fixed losses as described above. The locational element of the charge that encourages customers to connect in areas of spare capacity, is complemented by the element of the charge that apportions costs based on the assets used by the customer. Accordingly, where the locational charge is identical, it would be cheaper for a customer to connect where 1km of line is used to service that customer rather than 10km. This helps to reduce losses as they are broadly proportional to the distance that the electricity is transported.

Impacts from distributed generation charging

1.35. There are potential benefits to the environment from the connection of additional DG, 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.

1.36. For non-intermittent generation, the EDCM provides 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 DG 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.

1.37. We note that some intermittent generation (which typically uses renewable sources) will be charged for use of system for the first time. Should this cause existing renewable generation to shut down, or discourage new intermittent renewable generation, there may be a negative environmental impact. We have not been presented with evidence that the EDCM will have a material effect on their viability. We also recognise that there may be possibilities for these generators to reduce their charges by sizing their capacity closer to the average level of output for their generation source. We discuss this issue further in the section "Impact on generators".

1.38. We also note, as discussed in Issue 11 of Chapter 4 of the main document, that while intermittent generators will be charged, they will not receive credits. The DNOs do not propose that credits be given on the basis that their output does not offset reinforcement. In and of itself, there is no differential impact as a result of the EDCM, as DG does not currently receive credits for its output.

1.39. We believe that intermittent generators' output can be (and in some cases is) taken into account in network planning. We are therefore considering placing a condition on the DNOs to amend their EDCM to provide credits subject to the usual assumptions about the load factor of the generation. We believe that this will encourage the connection of more intermittent generation. In these circumstances, there would be a net benefit for sustainable development and this may go some way to offsetting the charges that intermittent generation will now pay. Further analysis on this can be found from paragraph 1.80 below.

Impacts on health and safety

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

Risks and unintended consequences

1.41. A key risk considered by both DNOs and Ofgem in the development of the EDCM was the possibility of breaching competition law. DNOs are monopolies and therefore have special requirements under competition law not to abuse this position. The boundaries of competition law may be tested where the model produces charges – whether intentional or not – in excess of the reasonable cost of serving a customer. Conversely, prices might be too low such that it may prevent the entry of a competitor.

1.42. With this in mind, a significant amount of work was put into making sure that the methodology is cost reflective, in order to ensure that the likelihood of such an outcome is minimised to the greatest extent. A key part of this was the choice of the method for allocating some costs and scaling charges to match revenue. As the DNOs report in Annex 4 of their submission, they chose a site-specific method which allocates direct costs, network rates and 80 per cent of the residual revenue based on an estimate of the shared assets a customer uses. They noted that they consider it produces charges that are more cost reflective than other methods. The DNOs also applied caps and collars in the calculation of the assets a customer uses to minimise the risk of anomalies from the power flow modelling used to identify the assets used by individual customers.

1.43. The complexity of the EDCM and number of inputs mean that any errors in the operation of the model or the input data may produce charges that are different from those intended. Subject to our approval of the EDCM, we expect DNOs to thoroughly check both the operation of the model and all input data to ensure it produces accurate charges for all customers.

1.44. The complexity of the EDCM, some of which results from the drive to be as cost reflective as practicable, may potentially result in unintended consequences. More broadly, external changes, such as developments in the distribution network may mean that the EDCM no longer continues to meet all of the Relevant Objectives over time and will need to be reviewed.

1.45. 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.

Other impacts, costs and benefits

1.46. Table 1.2 on the following page sets out the number of demand and generation customers per DNO area.

Table 1.2 Customer numbers by DNO area

DNO	Demand	Generation	Total
WPD W Midlands	30	15	45
WPD E Midlands	69	33	102
ENWL	80	33	113
CE NEDL	38	14	52
CE YEDL	102	28	130
WPD S Wales	61	36	97
WPD S West	51	32	83
UKPN LPN	30	7	37
UKPN SEPN	47	16	63
UKPN EPN	104	49	153
SP Distribution	69	41	110
SP Manweb	204	52	256
SSE Hydro	134	133	267
SSE Southern	84	28	112
All DNOs	1,103	517	1,620

Impact on EDCM demand customers

1.47. Changes in the level of tariffs vary widely across DNOs and between different customers. This section undertakes a more detailed analysis of the changes in charges. When looking at the analysis of how customers' charges change under the EDCM, a number of points should be taken into account.

1.48. The first is that the analysis we present here focuses on the change in the DUoS charge itself, not the DUoS charge as a proportion of the final electricity bill. DUoS charging represents a portion of a customer's electricity bill. For CDCM customers, this portion is on average 17 per cent and tends to be fairly stable, particularly for domestic customers.

1.49. For EDCM customers, we understand that the percentage varies significantly between customers. Accordingly, the final impact of a large change in charge depends on the proportion of the final bill that the DUoS charge accounts for. The change becomes less significant the smaller the proportion of the customer's final bill that the DUoS charge makes up. By contrast, what might otherwise be considered a relatively small rise may significantly impact a customer where the proportion is high. An example of this is a customer that requires a very high capacity connection that they use only a couple of times per year.

1.50. The second is that the tariffs presented by the DNOs assume no change in the customers' behaviour. It is important to note that the EDCM provides customers with a fair degree of scope to influence their charges by changing their behaviour. This is the natural result of the EDCM's objective in making charges more cost reflective and giving pricing signals.

1.51. The third point (closely related to the second) is that in the short term, changes in behaviour by customers that reduce individual charges will result in the saving to that customer being met by other customers. This is because allowed revenue is largely fixed and must be recovered through DUoS charges. In the longer term however, overall charges should reduce as a result of customers changing their behaviour as the options listed above will eventually result in lower overall investment required on the distribution network and therefore lower costs to customers.

1.52. The fourth point is that customers' charges are moving from seven different methodologies to a common methodology. There will be many different reasons why customers' charges are changing. Noting that there are around 1,100 demand tariffs, we do not consider the specific reasons why individual charges are changing. Rather we analyse the data of current and final charges at an aggregate level. The DNOs provide their explanation of significant changes in charges in Appendix 8 of their submission. We also recommend customers speak with their DNO to help them better understand the reasons why their tariff is changing.

1.53. The final point is that some customers may be on fixed price contracts, or other arrangements which mean the full change in charge may not be passed onto them, at least in the short term.

Analysis of changes in charges

1.54. Tariff changes vary widely across DNOs and between different customers. On average across DNOs, charges are decreasing. This decrease is experienced at all network connection levels except those customers connected to 132kV circuits. Similarly, demand customers in all DNO areas except CE's North East England region experience an average reduction in their charge. Table 1.3 below shows the average change in charge by level of network connection and DNO area.

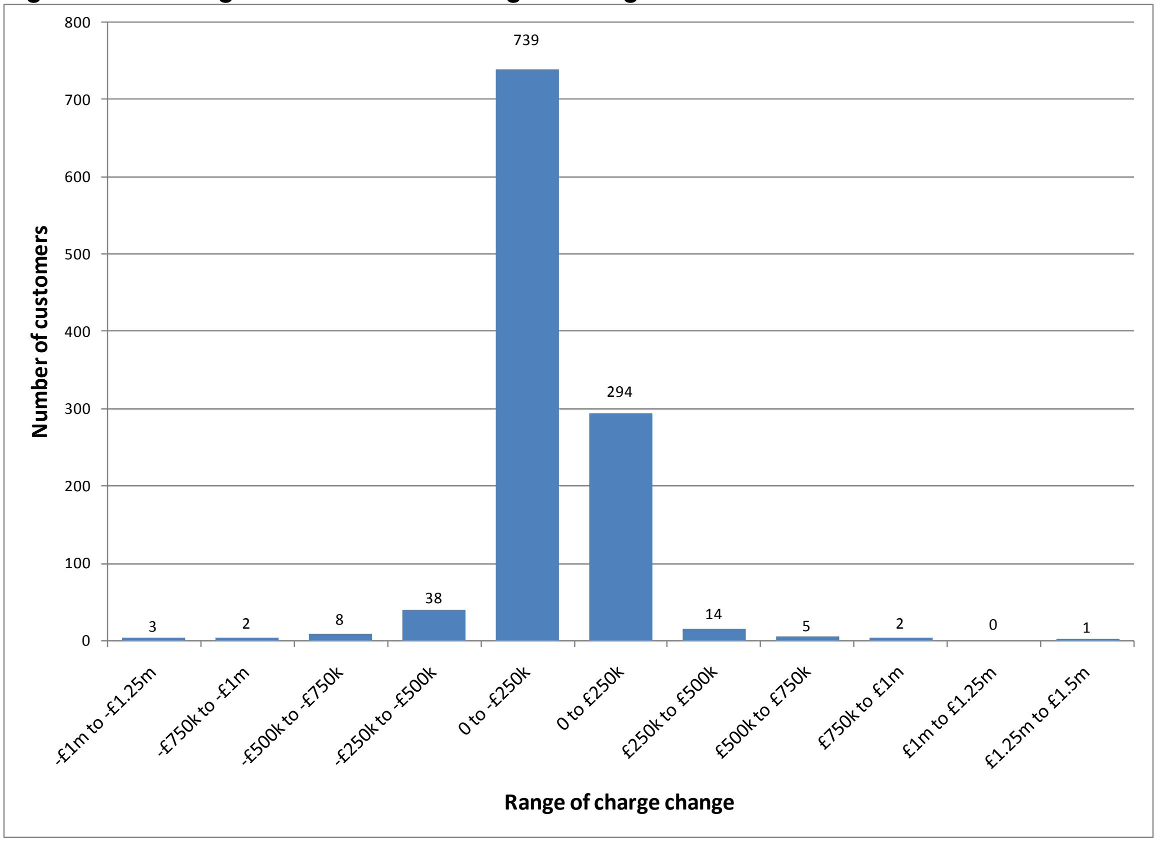
Table 1.3 Average change in charge (£) for demand customers by DNO and level of connection

DNO/Level	GSP	132kv	132/33kV	33kv	33/11kv	All network levels
WPD W Midlands	-88,335	67,359	-110,789	-25,689	-42,145	**-24,286**
WPD E Midlands	317	79,601	2,516	-42,696	-24,081	**-453**
ENWL	-48,415	-68,552	-39,080	-85,741	-25,360	**-48,048**
CE NEDL	-160,433	-16,908	-31,629	25,912	75,135	**13,631**
CE YEDL	-98,426	27,935	-82,655	-98,968	-14,958	**-61,693**
WPD S Wales	-216,936	-65,380	-3,123	-40,974	-47,229	**-50,142**
WPD S West		-2,892	6,212	-50,674	5,615	**-2,436**
UKPN LPN	-45,821	-242,684	-20,309	88,256		**-73,246**
UKPN SEPN	-242,965	-75,597	-108,411	-124,873	-10,228	**-121,444**
UKPN EPN	-35,585	60,108	-76,962	-74,215	-22,064	**-23,893**
SP Distribution	-143,921		-111,055		-67,631	**-113,251**
SP Manweb	-264,072	122,239	-52,270	2,462	33,021	**-24,188**
SSE Hydro	-96,466		-41,974		-3,061	**-26,179**
SSE Southern	-52,966	50,263	-47,796	22,596	-42,002	**-11,109**
All DNOs	**-110,424**	**6,961**	**-52,281**	**-47,249**	**-10,743**	**-37,228**

Nb blanks cells indicate that the DNO has no customers connected at that network level

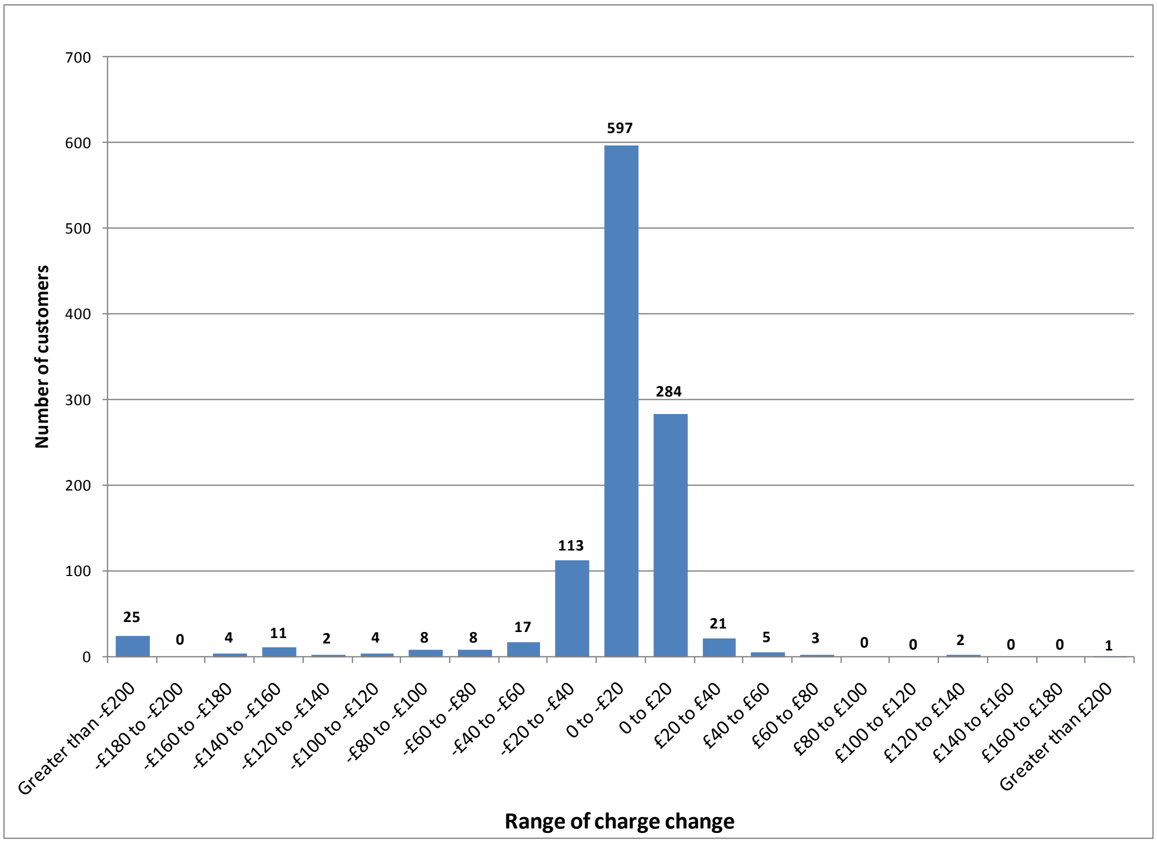
1.55. We recognise that the above table represents the average change in charges and that some customers will see very different changes to the averages presented. Figure 1.1 shows that the majority of customers (93% - the two tall bars), experience a change in their charge of less than £250k. The absolute highest charge increase for an individual customer is £1.37m (this represents an increase of 245%) and the largest reduction is £1.12m (this represents a decrease of 66%).

Figure 1.1 Range of absolute charge changes for EDCM demand customers



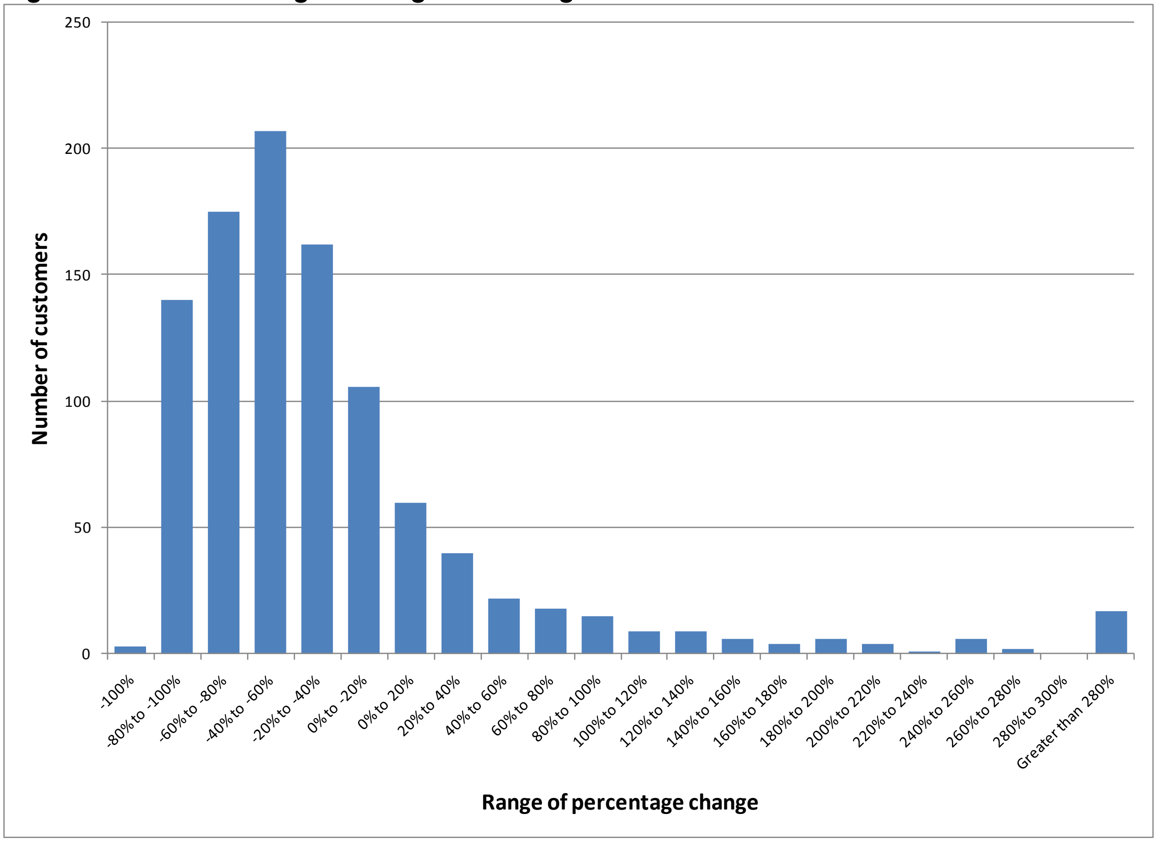
1.56. The change in pounds shows the change in absolute terms. However, the size of EDCM demand customers varies widely. In order to put these changes in charges into perspective, we have divided the change in charge for each customer by their agreed capacity (kVA). Capacity provides a proxy of the size of the customer, and is an appropriate measure as much of the EDCM charge is directly or indirectly driven by the customer’s capacity. Figure 1.2 shows that the majority of customers (80%) experience a change in their charge per unit of capacity of less than £20.

Figure 1.2 Range of charge changes for EDCM demand customers, per unit of capacity (kVA)



1.57. We also present the change in charge in percentage terms. It is important to note that presenting changes in percentage terms can mean some very high percentage changes where the current charge is relatively low. Figure 1.3 shows the distribution of percentage changes.

Figure 1.3 Percentage change in charge for EDCM demand customers



Impact of new charges

1.58. The above analysis focuses on the change in charge. This change will be a one off in the first year of the EDCM being implemented. The new charge is the cost that customers will face on an ongoing basis. Figures 1.4 and 1.5 present the new charges by absolute charge and charge divided by unit of capacity. The following charts shows that a great majority of customers (89%) will pay an annual charge of between £0 and £250,000, this equates to around half of customers paying between £0 and £10 per unit of capacity.

Figure 1.4 Range of charges for demand customers

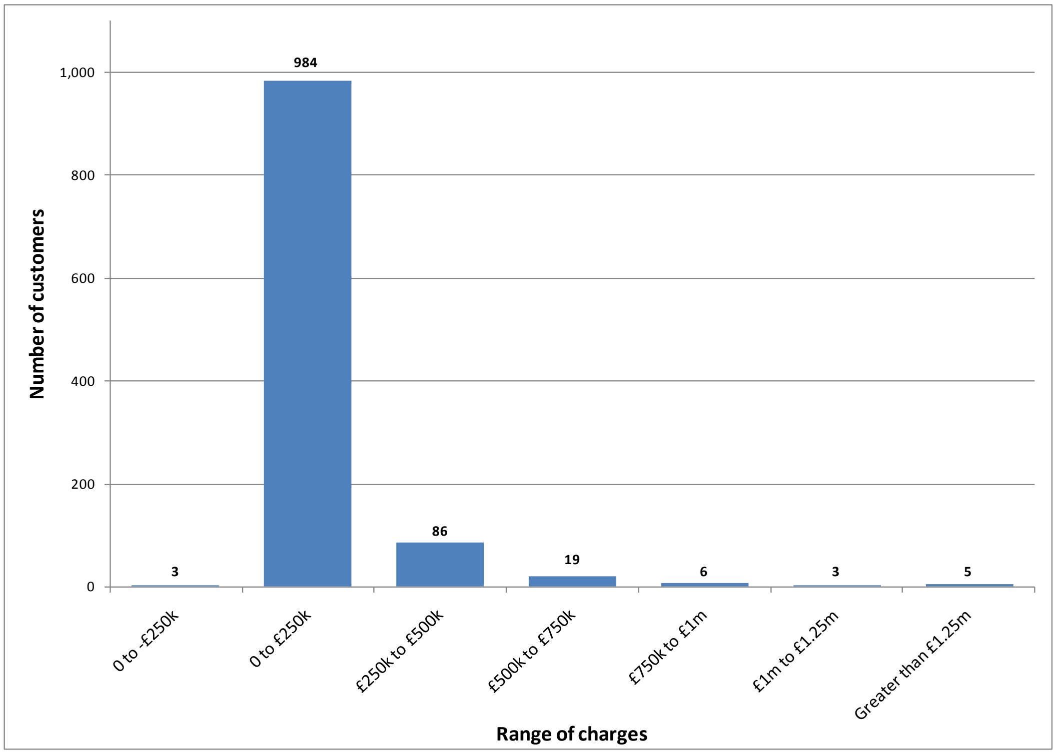
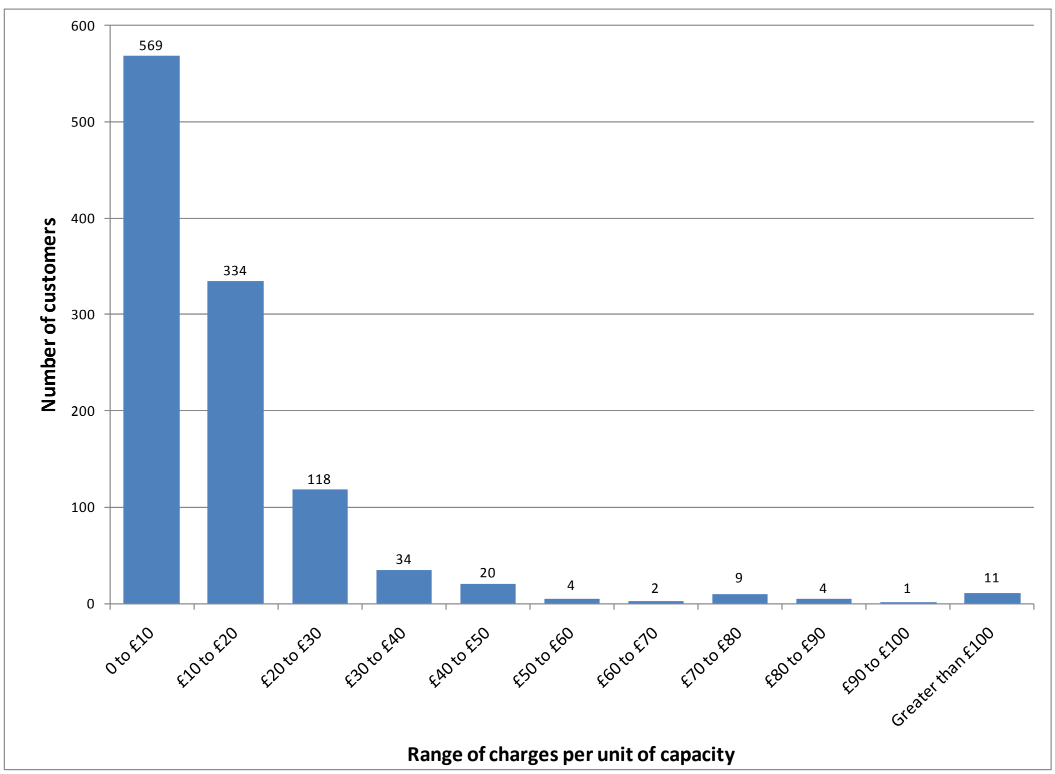


Figure 1.5 Range of charges for demand customers, per unit of capacity (kVA)



Impact from potential conditions (Option 2)

LRIC branch capping

1.59. There are two elements to this potential condition (the rationale for which is discussed in paragraph 2.33 in the main document). The first is to apply the cap to the LRIC charges and credits separately. This would result in more charges being capped as they would not be offset by the credits on that branch. This would reduce the LRIC component of demand customers' charges, where they are connected to that branch of the network.

1.60. The second element of this potential condition is to apply the caps separately to generation and demand. This would result in fewer customers' charges being capped as generation and demand would no longer be considered cumulatively.

1.61. Due to the complexity of running the LRIC model, assuming we apply this condition, the DNOs would need to undertake analysis to determine how many branches would be capped and hence the impact on customers' charges. Based on the evidence we have received, we understand that only a few branches are capped and where capping is applied the adjustment to charges is not large. We therefore expect the amendments to branch capping to have a minor impact on charges.

Spare capacity issue

1.62. The potential condition (paragraph 2.25 in the main document) to change the approach to calculating the network use factors (NUFs) and therefore the notional shared asset value attributable to each customer may have an impact on customers' charges. A significant impact would most likely occur at locations where two EDCM demand customers use only a small proportion of a large asset, with the rest of it being spare capacity.

1.63. If the 'cost'[3] of the spare capacity were to instead be spread across all other users, then the individual customers' charges would likely decrease, while all other customers' charges would increase by a small amount (as the cost would be spread across many customers).

1.64. We note that we discussed this issue with the DNOs prior to submission. Significant impacts such as in the example above may have been mitigated by the cap and collar on NUFs that were partly introduced for this reason. We are not aware of any customers that are materially affected by this issue, but expect the DNOs to identify any such customers.

[3] Actually the proportion of costs that is allocated on the basis of network use factors.

Ability to reduce charge

1.65. As mentioned in the introduction to this section, the tariffs presented by DNOs are illustrative and based on current customer profiles. There are a number of options that may be open to customers to reduce their charges:

- enter into a demand side management agreement to stop or reduce consumption at the request of the DNO
- reduce consumption during super-red hours
- reduce their agreed import capacity
- use on-site generation (recognising that this may be offset to some extent by any DUoS charge levied on the generation side)
- relocate at a place in the network where there is more spare capacity (recognising that this is more applicable to new rather than existing customers).

Impact on generators

1.66. A number of points should be borne in mind when considering the impact on generators.

1.67. The first is that the tariffs presented by the DNOs assume no change in the generators' behaviour. It is important to note that the EDCM provides customers with a fair degree of scope to reduce their charges by changing their behaviour. This is the natural result of the EDCM, that is, to make charges more cost reflective and give price signals. (As noted above, reductions in charges will affect other customers' charges.)

1.68. The second point is that for the generators who are currently being charged, their charges are moving from seven different methodologies to a common methodology. Accordingly, there will be many different reasons why generators' charges are changing. Noting that there are around 500 generation tariffs, we do not consider the specific reasons why individual charges are changing. Rather we instead analyse the data of current and final charges at an aggregate level. The DNOs provide their explanation for significant changes in charges in Appendix 8 of their submission. We also recommend generators speak with their DNO to help them better understand the reasons why their tariff is changing.

1.69. The third point is that the analysis of charges does not take into account the specific arrangements that may be made for generators who connected pre-2005 – in some cases there may need to be contractual changes before charges under the EDCM can be introduced. This issue is unbundled from the EDCM and we are currently consulting[4] on our guidance to the DNOs on what refunds can be recovered through their next price control. This Impact Assessment assumes that pre-2005 generators will be charged (or credited) from 1 April 2012.

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

1.70. The final point is that generators who have fixed price contracts with a supplier may not see the new charge or the change in charge (for those customers already subject to a charge) passed on straight away.

Analysis of charges for those generators previously charged

1.71. As mentioned in the paragraph above, around 100 of the 500 generators already pay DUoS charges (these generators would have signed connection agreements after 1 April 2005). For these generators the average charge will reduce under the proposed EDCM. Some of these generators, that were previously charged, would now receive a net credit under the proposed EDCM.

1.72. The following charts show the change in absolute terms (£) and per unit of capacity (£/kVa) for these customers as well as the percentage change in charge. We note that the range of changes is narrower than for demand customers.

Figure 1.6 Range of absolute changes for generators previously charged

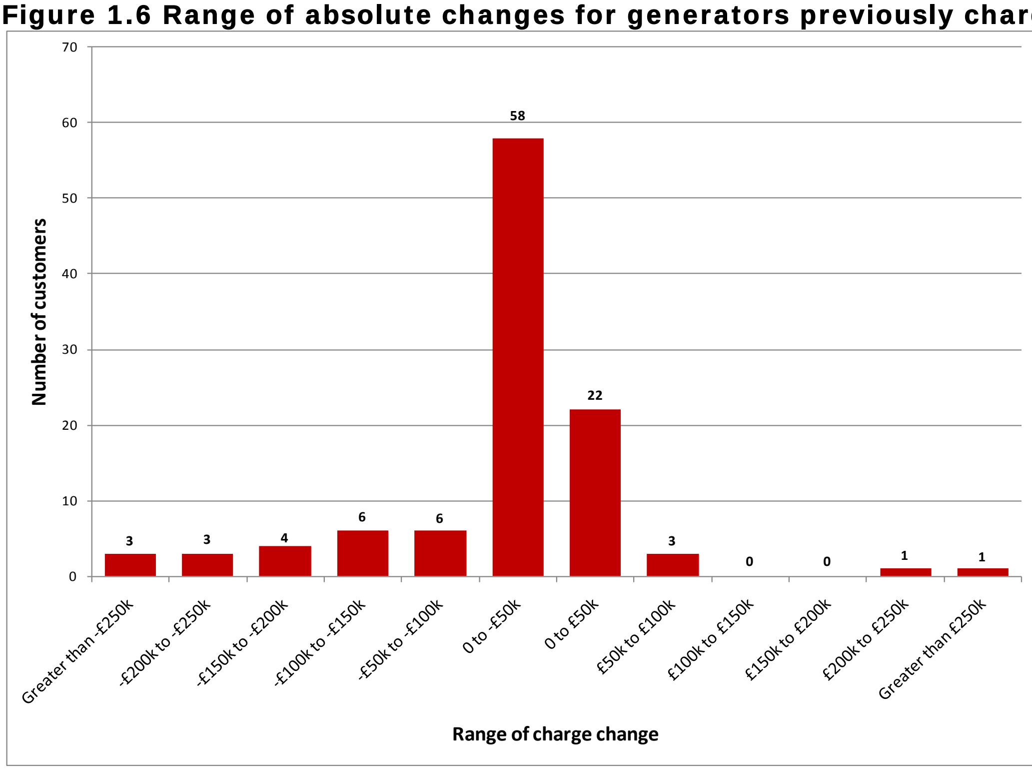


Figure 1.7 Range of absolute charge changes for generators previously charged, per unit of capacity (kVA)

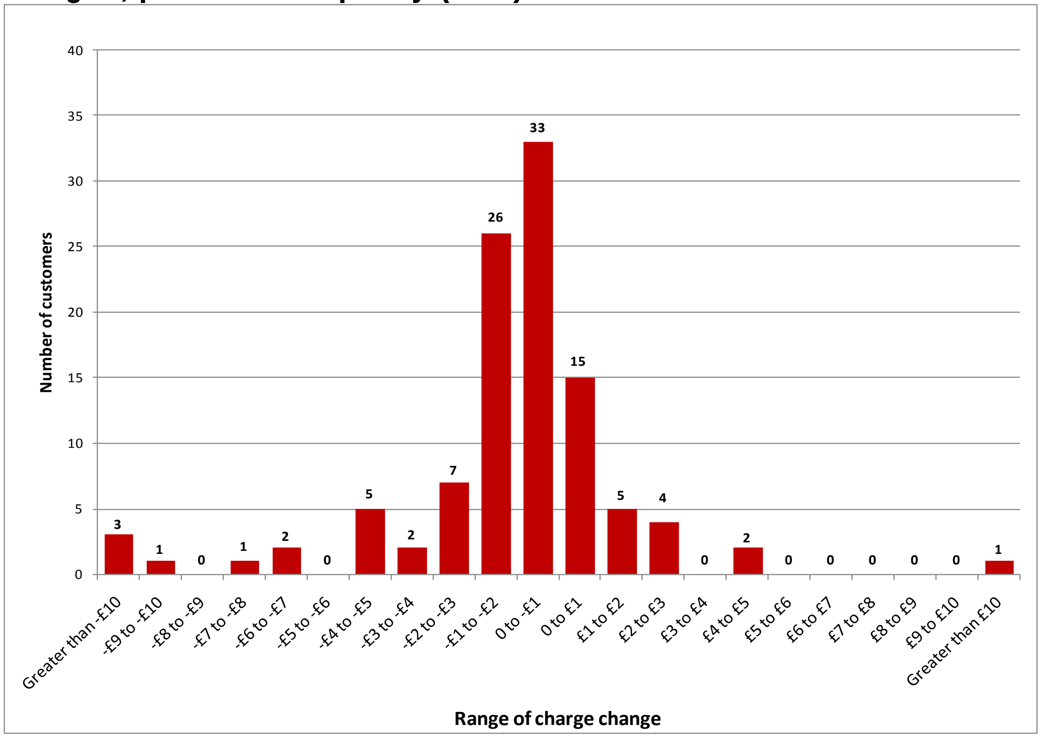
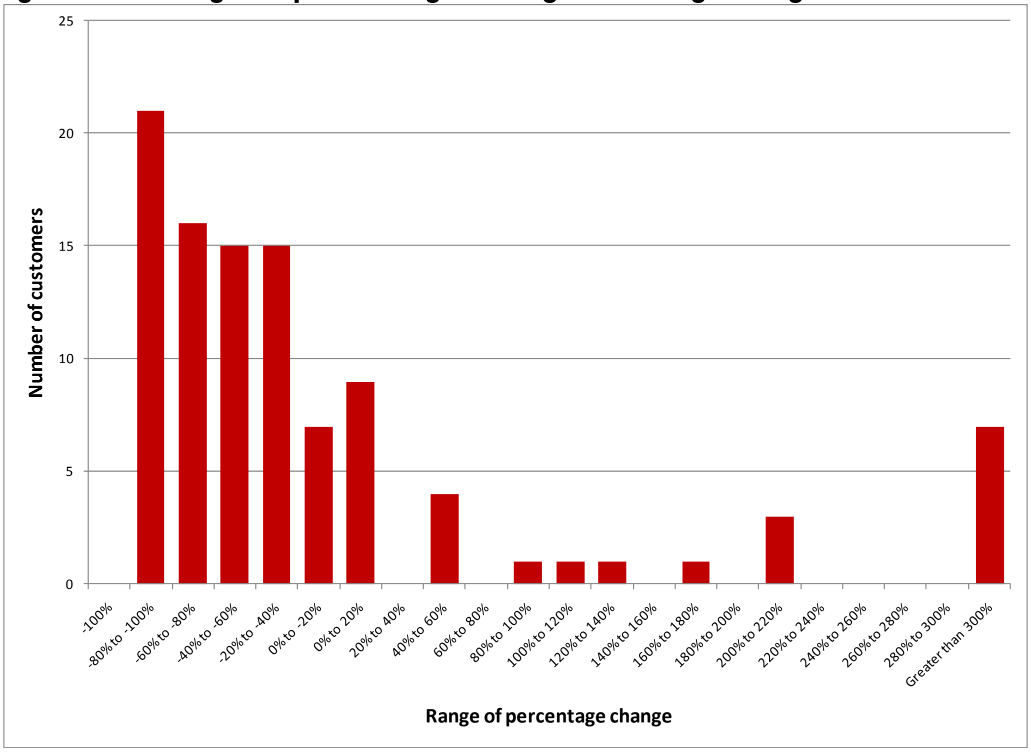


Figure 1.8 Range of percentage change in charge for generators



Nb this excludes six customers whose charge went from positive to negative (a credit).

Analysis of new charges

1.73. The majority of generators will be charged DUoS for the first time. The following analysis presents the impact of all new charges (including those who were previously charged) and those generators that will receive net credits.

1.74. Figure 1.9 shows that 12% of generators will receive credits under the proposed EDCM. The majority (72%) will receive a charge of up to £50,000 per annum. Figure 1.10 shows that the majority of customers see a charge increase, per unit of capacity, of between 0 and £3.

1.75. Under the DNOs' proposal intermittent generators would only be charged for DUoS, ie there would be no credits. Figures 1.11 and 1.12 show that the majority (81%) will face an annual charge of up to £50,000.

Figure 1.9 Range of absolute charges for all generators

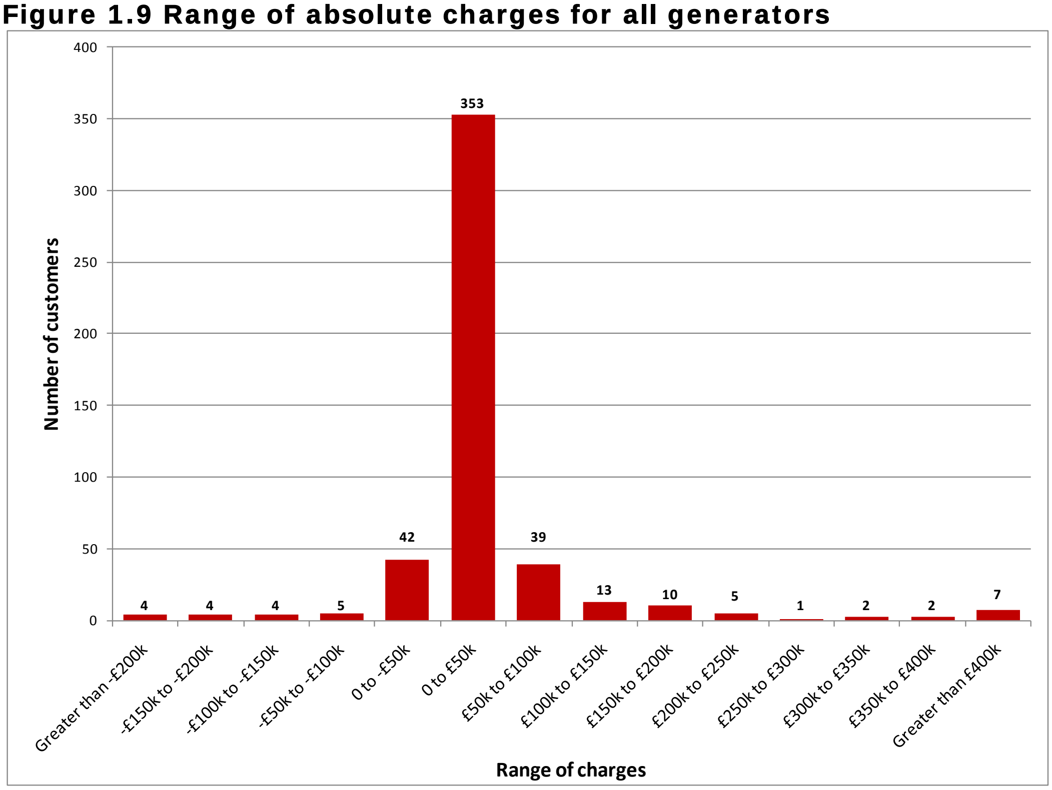


Figure 1.10 Range of absolute charges for all generators, per unit of capacity (kVA)

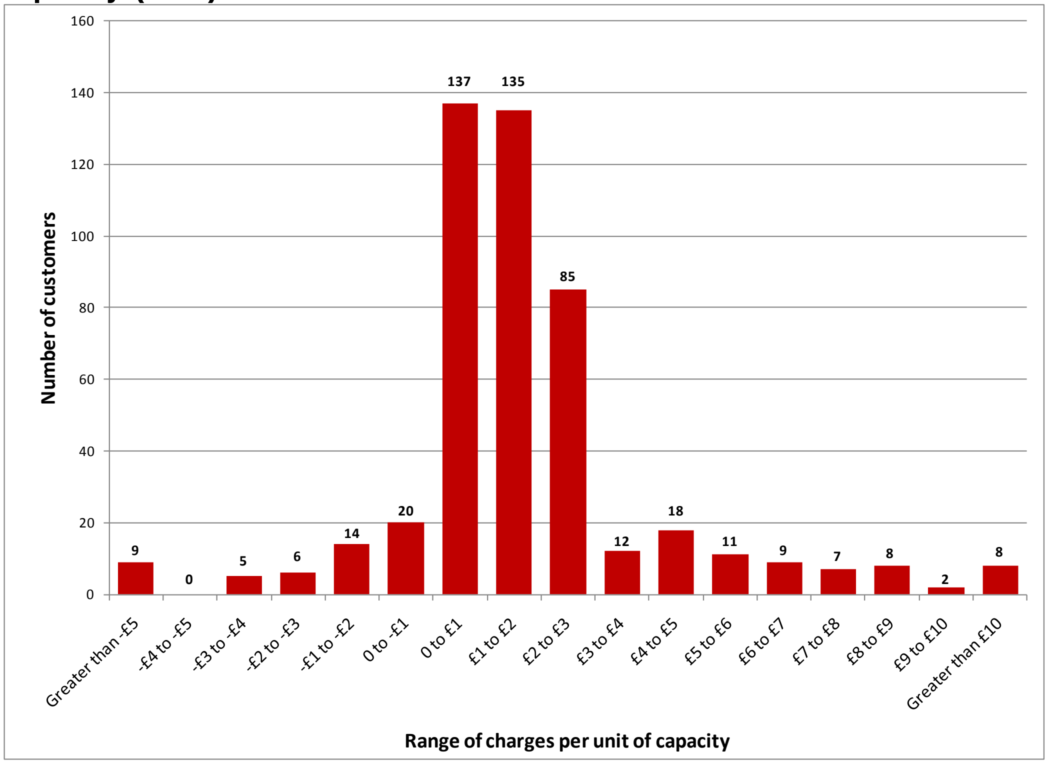


Figure 1.11 Range of absolute charges for intermittent generators

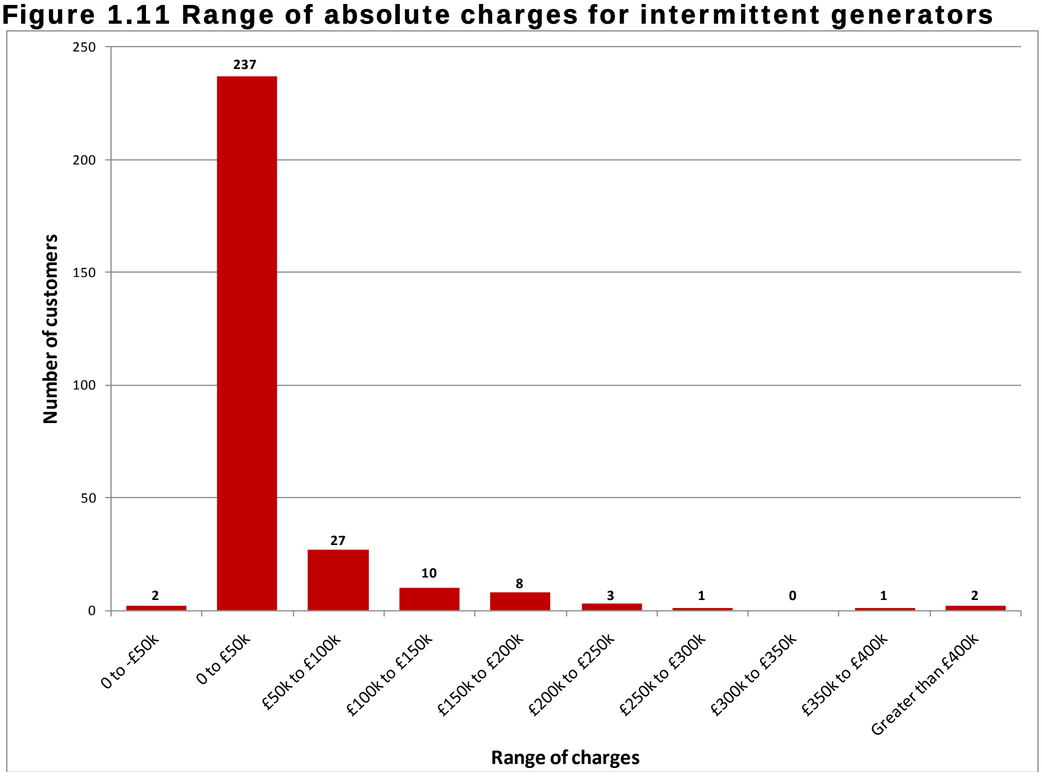
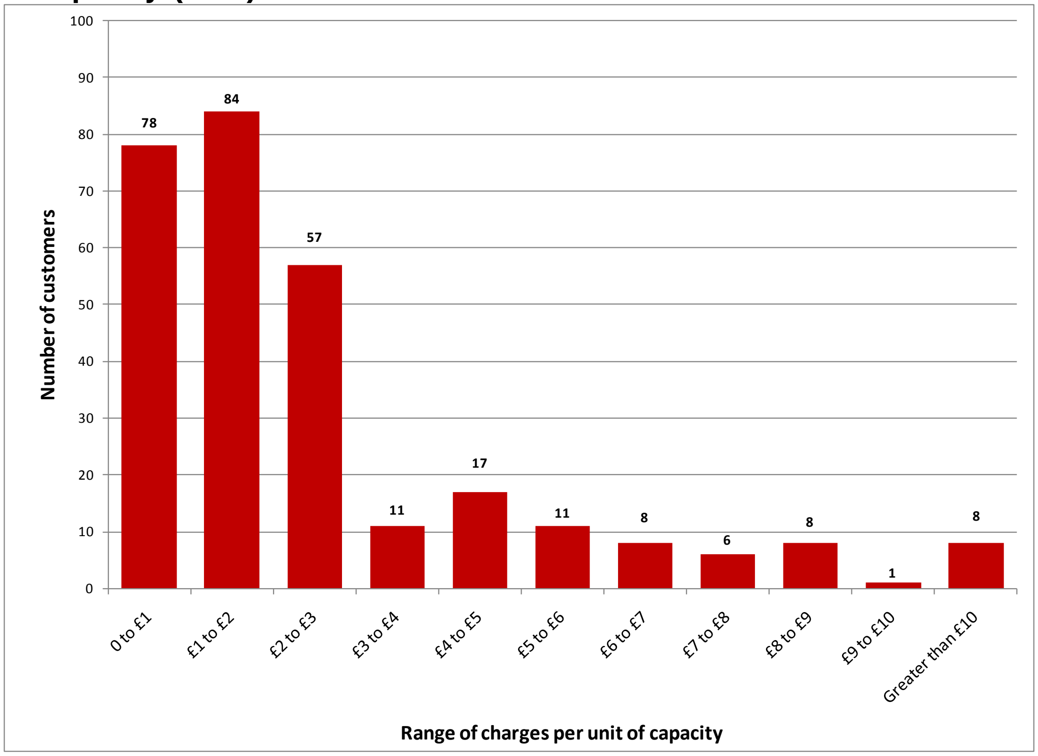


Figure 1.12 Range of absolute charges for intermittent generators, per unit of capacity (kVA)



Charges relative to estimated revenue

1.76. EDCM charges are significantly driven by export capacity. A generator's revenue is driven by units exported, which in turn, reflect the use of this capacity. Therefore the impact, in terms of DUoS charges relative to turnover, will be larger for generators that utilise less of their capacity. Our analysis[5] shows a very large impact for some generators that export a very small amount relative to their capacity.

1.77. However, we note that some generators may intentionally operate in this way as they may only export when the commodity price of export is very high. We also note that the the availability of Renewable Obligation Certificates for renewable generation may also help to mitigate the impact of low output per unit of capacity.

1.78. Our analysis also shows that, subject to the above caveats, if these generators were to generate closer to their potential - as suggested by the application of conservative load factors[6] - then the DUoS charge as a proportion of their estimated revenue from generation is likely to be small. Ninety per cent of generators would pay less than 2.7 per cent of their estimated revenue in DUoS charges. Ninety-nine per cent would pay less than 7.4 per cent of revenue in DUoS charges, with the

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[5] Based on EDCM input data and a set price for intermittent and non-intermittent generation.
[6] We have assumed 20 per cent for intermittent and 60 per cent for non-intermittent.

highest at 15 per cent (primarily because it has a significant future reinforcement cost relative to its capacity).

1.79. We recognise that simply increasing output may not be an option (or as noted, may not reflect the way the generator wishes to operate). We discuss at paragraph 1.86 below the options that may be open to a generator to reduce their charge.

Impact from potential conditions (Option 2)

Credits for intermittent generation

1.80. If the condition described in paragraph 2.27 of the main document were to be applied, then intermittent generation would also be eligible for credits. We anticipate that this would result in a small amount of credits being paid to intermittent generators.

1.81. The credits would also be different for intermittent generation compared to non-intermittent generation. This is because under our proposed condition, these credits would be calculated in a different way, reflecting the different characteristics of intermittent generation. Under our proposal, credits would only be applied to network levels above the level of connection, but would apply to all units exported, rather than just those exported during the DNO's super-red period.

LRIC branch capping

1.82. As mentioned in the section on demand, there are two elements to this potential condition (the rationale for which is discussed at paragraph 2.33 in the main document). The first is to apply the cap on how much the LRIC charge can be to charges and credits separately. This would result in more charges being capped as they would not be offset by the credits on that branch. This would result in a reduction in the LRIC component of generation customers' charges where they are connected to that branch of the network.

1.83. The second element of this potential condition is to apply the caps separately to generation and demand. This would result in fewer generators' charges being capped as generation and demand are no longer considered cumulatively.

1.84. Due to the complexity of running the LRIC model, assuming we apply this condition, the DNOs would need to undertake analysis to determine how many branches would be capped and hence the impact on generators' charges. Based on the evidence we have received, we understand that only a few branches are capped and where capping is applied the adjustment to charges is not too large. Accordingly, we expect the amendments to branch capping to have a minor impact on charges.

The generation revenue target

1.85. This potential condition is described in paragraph 2.29 of the main document. The change would be to extend the application of the 'sole use asset factor' to post-2005 generators' capacity (in addition to pre-2005 capacity as the DNOs propose). This would reduce the size of the generation revenue target and therefore generator's charges.

Ability to reduce charge

1.86. The tariffs presented by the DNOs assume no change in the customers' behaviour. As noted in the section on demand above, generation customers may similarly have an ability to reduce their charge by changing their behaviour. For generators, this could mean:

- entering into a generation side management agreement to stop or reduce export at the request of the DNO
- increase export during super-red hours (or reduce export if in a generation-dominated area)
- reduce their agreed export capacity (as mentioned in the section above).

Impact on suppliers

1.87. As noted in the impact on competition, we expect suppliers to benefit from the fact that the EDCM is a common methodology across all DNO areas.

1.88. In terms of a direct financial impact, we understand that most suppliers' contracts with EDCM customers include 'pass through' arrangements for DUoS charges. This means that any change in DUoS will directly flow through to the customer, thereby minimising the impact on suppliers.

1.89. In the above sections on charges to demand and generation customers we discussed that some suppliers may have fixed price contracts with their demand customers, or another arrangement that do not see DUoS charges, or changes in DUoS charges, passed through to the customer. In these circumstances, the supplier would bear the cost of the change, at least until the contract or prices are next updated (if possible).

Impact on LDNOs and their customers

1.90. As is the case with suppliers, we expect LDNOs to benefit from the commonality of the EDCM as it should enable them to more easily operate across DNO areas.

1.91. The introduction of specific discounts to the LDNOs arguably has a greater impact on future LDNOs and their customers, rather than current LDNOs. This is because only a handful of LDNOs are connected at the higher voltages that are covered by the EDCM and no LDNO has a customer where that customer itself is connected at the higher voltages.

1.92. Specific provisions for the calculation of discounts for LDNOs were introduced in the CDCM. The impact was to aid competition for the distribution of electricity as under the CDCM there is certainty and consistency in respect of the margins that may be earnt. However, the CDCM discounts only applied to LDNOs whose voltage of connection was also covered by the CDCM (ie LV and HV). LDNOs who connected at the higher voltages receive a charge as if they were any other higher voltage customer.

1.93. The EDCM addresses this by providing specific discounts for CDCM customers served by an LDNO who is connected at the higher voltages.[7] The actual variance in the effective discount for the handful of LDNOs connected at the higher voltages is likely to differ depending on where and how they are currently connected. This is in the same way that another higher voltage customer's charge will vary.

1.94. There is no affect on CDCM customers served by LDNOs as their charges remain the same whether they are served directly by a DNO or via an LDNO. As noted, there are currently no customers at the higher voltages that are served by LDNOs.

Impact from potential condition (Option 2)

1.95. In the main document, we consider placing a condition on the DNOs to provide a discount on the 20 per cent of residual revenue that is allocated with reference to the customers capacity (and how much of it they use during system peak). If this condition was implemented, the discounts to LDNOs would improve, as they would no longer have to absorb this 'cost' within the other elements of their charge.

Impact on DNOs

1.96. The impact from changes in customers' charges for DNOs is minimal. The DNOs continue to recover their allowed revenue from their customers; the EDCM simply splits this revenue between the DNOs customers in a different way to their current charging methodologies. There are also small impacts from the implementation of the new methodology itself, for example in running the power flow model each year that produces the notional asset values.

Post-implementation review

1.97. We will monitor the impact of the EDCM through the Distribution Charging Methodology Forum and through our links with suppliers and users. Parties that are materially affected by charges (including users, DNOs and suppliers) will be able to

[7] The discounts can be found in Appendix 1B of the submission.

raise changes to the methodology through the DCUSA-based open governance arrangements which will be managed by its subgroup, the Methodology Issues Group. This will allow for changes, refinements and improvements to the methodology over time.

Conclusion

1.98. As set out in Chapter 2 of the main document, we consider that the proposed EDCM is capable of approval subject to a number of potential conditions. We seek views both on our general assessment of the EDCM and the potential conditions. We also welcome views on the analyses contained in this Impact Assessment and whether there are any other impacts that we have not outlined here.

1.99. The methodology results in some large changes in charges for some customers. However, we note that on average, EDCM customers charges are going down. We also recognise that one off changes in charges is the unavoidable product of moving from numerous disparate charging methodologies to a single common methodology for EHV customers. We believe that the costs of moving to the common methodology are outweighed by the benefits of the EDCM. This includes greater cost reflectivity as well as benefits from lower overall network investment and environmental benefits through encouraging distributed generation to connect to the network.

1.100. Accordingly, we prefer Option 2. That is, to approve the EDCM with conditions. We believe that the potential conditions will rectify a number of remaining issues with the EDCM either prior to implementation or as soon as possible after implementation.