

**EHV Distribution Charging Methodology (EDCM)**

**Appendix 1: Report on conditions 1 and 2**

**November 2011**

**enda**  
energy**networks**  
association



## **EDCM Condition 1 and 2 report**

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## Introduction

1. The electricity Distribution Network Operators (DNOs), through the Energy Networks Association (ENA), jointly developed proposals for a new use of system charging methodology for higher voltage network users (the EDCM).
2. These DNOs' proposals for the EDCM were submitted by the ENA to Ofgem on 1 April 2011. This submission relates to the calculation of import and export charges for eligible customers. Documents relating to the submission and previous consultations are available to download from the website of the ENA.<sup>1</sup>
3. On 6 September 2011, Ofgem published its decision to approve these proposals for import charges only, subject to several conditions.<sup>2</sup>
4. This report is submitted by the Energy Networks Association on behalf of the 14 regional electricity distribution licensees (DNOs) in Great Britain to accompany revised proposals for the EDCM. These revisions have been made, in part, to satisfy the two conditions that need to be met before 30 November 2011.<sup>3</sup>
5. Subject to approval by Ofgem, EDCM import charges calculated using the LRIC and FCP methodologies set out in these revised proposals will apply to customers connected at extra high voltage (EHV), or connected at high voltage (HV) and metered at a primary substation from 1 April 2012.
6. The revisions that have been made to the EDCM methodology that was submitted on 1 April 2011 reflect:
  - a) Changes made by the DNOs to comply with conditions 1 and 2 of Ofgem's approval of the EDCM for demand only.
  - b) Changes necessitated by Ofgem's decision to delay the implementation of the EDCM for export charges.
  - c) Changes made to remove ambiguities or improve clarity in the original submission.
7. This report focuses on (a) above.
8. A separate document that focuses on (b) and (c) is submitted alongside this report as Appendix 2.

### Condition 1 – LDNO categories

9. Condition 1 of Ofgem's approval of the demand-only EDCM relates to the methodology for calculating portfolio charges for LDNOs serving customers who would have qualified for the CDCM had they been connected directly to the DNO.
10. Annex 1 of the Ofgem decision document says:

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<sup>1</sup> <http://2010.energynetworks.org/structure-of-charges-edcm/>

<sup>2</sup> Ofgem (2011) Electricity distribution charging: decision on the methodology for higher voltage import charges, ref 116/11

<sup>3</sup> Conditions 1 and 2 of Ofgem's decision, see Ofgem (2011) Electricity distribution charging: decision on the methodology for higher voltage import charges, ref 116/11.

“In our consultation document we stated that “We do not think that it is consistent to vary the discount with the assets provided by the DNO because the charge to the end customer (the “all the way charge”) is the same for CDCM customers regardless of the assets provided by the DNO. We think that doing so has the potential to distort competition and does not appropriately reflect differences in the relevant costs.

We have decided to place a condition on the DNOs to reduce the number of customer categories for LDNO discounts so that discounts do not vary with the network levels the DNO provides above the point of connection. This means that in England and Wales the number of customer categories for LDNO discount would reduce from 15 to five and in Scotland it would reduce to three.

This condition must be met by 30 November 2011.”

11. This text requires the DNOs to reduce the number of LDNO categories from 15 to 5 in England and Wales and 3 in Scotland “so that discounts do not vary with the network levels the DNO provides above the point of connection”.
12. The document did not suggest alternatives to the proposed methodology to meet this condition. There are potentially a number of methods that would give 5 or 3 discount categories such that discounts do not vary with the network levels above the level of connection.
13. In developing an alternative set of LDNO categories, we have relied on two sources of information:
  - a) Explanatory text from Ofgem’s decision document (in particular, paragraphs 2.7 and 2.10).
  - b) Feedback received from Ofgem and LDNOs following publication of Ofgem’s decision.
14. Paragraph 2.7 of Ofgem’s decision document says:

“2.7. We think that varying Method M discounts based on the network levels provided by the DNO undermines the validity of the model to generate appropriate discounts as the EDCM charges are fixed within a DNO’s region. The margins that are calculated under network configurations that include all network levels reflect the average cost of the DNO’s actual network. This means that the various network configurations are already taken into account on average. We do not think that a further discount on top of this is consistent with the Method M approach.”
15. Paragraph 2.10 says:

“2.10. We think that giving LDNOs a further discount where upstream network levels do not exist is not appropriate. The LDNO is not providing any more assets or service than it does when those network levels are present: the additional discount may represent a windfall gain for the LDNO at the expense of the DNO’s other customers. This additional margin is effectively transferred from other customers who must meet the shortfall in allowed revenue that is not recovered from the LDNO. We do not consider it necessary or desirable to provide a margin to LDNOs that would be in excess of the costs of an as efficient competitor.”

16. In paragraph 2.7, Ofgem says that margins that are calculated under network configurations that *include all network levels* reflects the average cost of the DNO’s actual network. In paragraph 2.10, Ofgem says that giving LDNOs a further discount where upstream network levels do not exist [compared to a hypothetical LDNO boundary where all upstream network levels do exist] is not appropriate.
17. The DNOs have now changed the methodology for calculating LDNO discounts. LDNO discounts would now be based on 5 discount categories (in England and Wales) and 3 discount categories (in Scotland) based solely on the network level of the boundary between the host DNO and the LDNO. The new list of categories would be as follows:
  - a) Discount category 0000 – This applies to original LDNO category 0000.
  - b) Discount category 132kV (in England and Wales only) – This applies to original LDNO category 1000.
  - c) Discount category 132kV/EHV (in England and Wales only) - This applies to original LDNO categories 1100 and 0100.
  - d) Discount category EHV - This applies to original LDNO categories 1110, 0110 and 0010.
  - e) Discount category HVplus - This applies to original LDNO categories 1111, 0001, 1001, 0002, 0011, 0111, 1101, 0101.
18. For each combination of an end user network level and a boundary network level, the relevant discount for demand end users would now be calculated as follows:

**For discount categories 0000, 132kV/EHV and HVplus**

$$\text{Discount percentage} = P / (S + U)$$

**For discount category 132kV**

$$\text{Discount percentage} = (P + ([\text{percentage for 132kV}] * (1 - ([\text{network length split for 132kV}] * [\text{direct cost proportion}])))) / (S + U)$$

**For discount category EHV**

$$\text{Discount percentage} = (P + ([\text{percentage for EHV}] * (1 - ([\text{network length split for EHV}] * [\text{direct cost proportion}])))) / (S + U)$$

Where:

Discount percentage is the discount applicable for each combination of discount and end user type.

P is the sum of the percentages for all network levels below the network level of the LDNO-DNO boundary up to and including the network level of the end user.

S the sum of the percentages for all network levels in the distribution network above and including the network level of the end user

U is the ratio of the sum of the DNO's total incentive revenue and the transmission exit charge, and the DNO's total allowed revenue including any incentive revenue and transmission exit charge.

Network length split is equal to 1 minus the ratio of the average length of circuits on relevant network level (EHV or 132kV) that is deemed to be provided by the LDNO to that provided by the host DNO. The values for the "network length split" for 132kV and EHV are currently set to 100 per cent.

Direct cost proportion is the percentage share of direct costs in the sum of direct costs and indirect costs (excluding IT and telecoms and property management costs) at EHV. Negative costs will be excluded from the calculation.

19. In addition to changes necessitated by the proposal to meet Condition 1, the formulas for discount categories 132kV and EHV have been changed to incorporate an additional component. This change is being made following Ofgem's approval of the DCUSA change proposal DCP071A, and is explained in the accompanying "other changes" report (Appendix 2).
20. This change does not affect the calculation of charges to LDNOs in respect of end users connected to their network who would have qualified as an "EHV designated property" had they been connected directly to a DNO's network.
21. Table 1 sets out, by DNO area, the number of DNO-LDNO interconnections that are likely to be affected by this proposal. This data is correct as of 11 October 2011
22. Appendix 4 sets out illustrative discounts that would apply if the new proposed LDNO categorisation were to be used.

**Table 1 Number of LDNO-DNO interconnections likely to be affected (as of 21 November 2011)**

<b>DNO area</b>	<b>Number of inter-connections</b>	<b>Nature of change</b>
CE NEDL	1	1100 to 132kV/EHV (no change in discounts)
	1	0010 to EHV (reduction in discounts)
CE YEDL	None	
ENW	3	1100 to 132kV/EHV (no change in discounts)
SPEN SPD	2	0000 to 0000 (no change in discounts)
SPEN SPM	None	
SSEPD SEPD	None	
SSEPD SHEPD	None	
UKPN EPN	None	
UKPN LPN	2	1000 to 132kV (no change in discounts)
	2	0010 to EHV (reduction in discounts)
	1	1001 to HVplus (reduction in discounts)
UKPN SPN	None	
WPD East Midlands	1	1100 to 132kV/EHV (no change in discounts)
WPD West Midlands	None	
WPD Wales	1	1100 to 132kV/EHV (no change in discounts)
	1	1001 to HVplus (reduction in discounts)
WPD West	None	

**Condition 2 – To modify the method of sense-checking of LRIC branch incremental costs**

23. Annex 1 of Appendix 2 of the Ofgem decision document says:

In our consultation document we stated that in relation to the application of caps on the amount that can be recovered from LRIC charges applicable to each branch, “we think that overall cost recovery should consider positive recovery and negative recovery separately”. We think it would more accurately reflect the costs of future reinforcement to ensure that total charges paid in respect of bringing forward the expected time of reinforcement of a branch do not exceed the (annuitised) reinforcement cost of the asset. Similarly, we think that total credits paid for deferring the expected time of reinforcement of an asset should not exceed the (annuitised) reinforcement cost of the asset.

We have decided to place a condition on the DNOs to amend the sense checking mechanism such that positive cost recovery and negative recovery are separately assessed against the reinforcement cost of the branch.

This condition must be met **by 30 November 2011**.

24. The calculation of marginal charges and credits with the Long Run Incremental Costing methodology is based on the changes in power flow through branches and their utilisation due to the application of increments of load at nodes on a network and the corresponding changes in the expected time to reinforcement for those branches. The methodology contains a mechanism for the identification and exclusion of some branches from contribution to marginal charges (and credits) in the cases for which the changes in branch utilisation are deemed to be excessive or non-credible.
25. The sense-checking mechanism now involves separate comparisons of positive or negative cost recoveries associated with a branch against the annuitised cost of that branch (the product of the annuity rate and the cost of the reinforcement solution of that branch). Two ‘recovery factors’ - *PositiveCostRecoveryFactor* and *NegativeCostRecoveryFactor* are calculated which are then employed in the derivation of marginal charges and credits respectively. This four-step process is equally applicable to positive and negative cost recoveries and consists of the following stages:
  - a) calculation of the total cost recovery (either positive or negative) associated with a branch for each node on the network,
  - b) comparison of the total branch cost recovery (positive and negative in turn) against the annuitised cost of the branch,
  - c) calculation of the ‘cost recovery factor’ (either positive or negative) and
  - d) calculation of marginal charges with the use of both the ‘recovery factors’.

*Step 1 - Calculation of the total cost recovery (either positive or negative) associated with a branch:*

26. The incremental cost of a branch due to the application of an increment of load at each node on the network is calculated as described in the methodology. The branch cost recovery associated with that node is calculated by multiplying the incremental rate (incremental cost divided by the increment) by the modelled load at that node. Algebraic sign of the branch cost recovery for that node is then checked and the branch cost recovery is put into either positive or negative ‘pot’. The total positive recovery associated with a branch is calculated by the aggregation of the positive

branch cost recoveries associated with each node on the network across all nodes with respect to that branch. Similarly, the total negative recovery associated with a branch is calculated by the aggregation of the negative branch cost recoveries associated with each node on the network across all nodes with respect to that branch.

*Step 2 - Comparison of the total branch cost recovery (positive and negative in turn) against the annuitised cost of the branch:*

27. The absolute value of the total positive and negative branch cost recovery calculated above are then compared to the annuitised cost of the branch. Both positive and negative branch cost recoveries are deemed excessive if the former is greater than the latter.

*Step 3 - Calculation of the cost recovery factors:*

28. If the total cost recovery associated with a branch (either positive or negative) is deemed to be excessive, a corresponding 'cost recovery factor' is calculated which is then employed in the subsequent marginal charge (or credit) calculation. This factor is calculated by dividing the annuitised cost of a branch by the total recovery associated with that branch (either positive or negative)

*Step 4 - Calculation of marginal charges (and credits) with the use of the 'cost recovery factors':*

29. Marginal charges (and credits) are calculated as set out in the methodology but the cost recovery factors are applied to the incremental costs for only those branches for which total positive or negative cost recovery was deemed excessive.