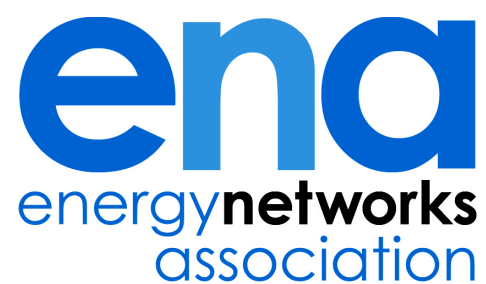


EHV Distribution Charging Methodology (EDCM)
April 2011



EHV distribution charging methodology (EDCM)

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Introduction

1. The electricity Distribution Network Operators (DNOs), through the Energy Networks Association (ENA), have jointly developed proposals for a new use of system charging methodology for higher voltage network users (the EDCM). From 1 April 2012, the EDCM will apply to customers connected at extra high voltage (EHV), or connected at high voltage (HV) and metered at a primary substation.
2. CE Electric, Central Networks, UK Power Networks, Electricity North West, SP Energy Networks, SSE Power Distribution and Western Power Distribution jointly prepared these proposals on behalf of the 14 entities licensed as Distribution Services Providers pursuant to condition 50A of the standard distribution licence conditions.
3. The EDCM will result in improved cost-reflective charges using a common methodology. Final charges will be locational, reflecting the degree to which the local and higher network has capacity to serve more demand or generation without needing reinforcement. Locational charges are intended to help limit the need for network investment, and hence put downward pressure on future charges.
4. Documents relating to the EDCM, including those relating to prior consultations, are available to download from the website of the ENA.¹
5. This report is accompanied by the following appendices:
 - a) Appendix 1, attached as two Microsoft Excel workbooks, gives, for each of the 14 DNO licence areas in Great Britain, illustrative tariffs that might have resulted from the application of the EDCM in 2011/2012. One contains results for end-users and the other for LDNOs;
 - b) Appendix 2 contains the long run incremental cost (LRIC) and forward cost pricing (FCP) methodology statements;
 - c) Appendix 3 sets out the main areas of risk in the implementation of the EDCM, both at a generic level and at the level of individual DNOs;
 - d) Appendix 4 provides the super-red (peak) time bands applicable in each DNO area;
 - e) Appendix 5 provides an analysis of the potential volatility of charges under the EDCM;
 - f) Appendix 6, attached as four Microsoft Excel workbooks, gives fully functional blank EDCM models for both methodologies (FCP and LRIC), and blank ;
 - g) Appendix 7 contains a common LC14 charging statement to include the application of EDCM charges
 - h) Appendix 8 sets out commentary from individual DNOs on the justification of charges in their areas.

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

- i) Appendix 9 sets out a discussion of the areas of the proposed methodology that the DNOs consider represent significant deviations from Ofgem's original specifications for the EDCM.²
6. This report contains the following annexes:
- a) Annex 1 contains the text of Condition 50A of the standard distribution licence.
 - b) Annex 2 describes the method used to calculate site specific shared asset values.
 - c) Annex 3 describes the method used to calculate the EDCM demand revenue target.
 - d) Annex 4 explains the rationale for our choice of demand scaling approach.
 - e) Annex 5 describes the rationale for the split between the capacity-based and asset-based elements of demand scaling.
 - f) Annex 6 describes the methodology used for demand scaling.
 - g) Annex 7 describes the method used for generation scaling.
 - h) Annex 8 describes the method for calculating portfolio tariffs for Licensed Distribution Network Operators (LDNOs).

Objectives of the EDCM

7. The objective of the EDCM is to produce cost reflective Use of System charges to encourage existing and new users of the electricity distribution networks in Great Britain to:
- a) Use existing network capacity more efficiently; and
 - b) Avoid prompting inefficient network reinforcement.
8. We expect this to be achieved by the locational EDCM which could lead to higher prices in areas where network capacity is scarce but lower prices in areas where network capacity is plentiful. The EDCM also includes credits for distributed generation that are deemed to offset the need for demand-led network investments.
9. Where the EDCM leads to lower investment in the distribution network, this will result in lower use of system charges for all customers over time.
10. Condition 50A of the standard distribution licence applicable to the DNOs set out the relevant objectives of the EDCM. Condition 50A also sets out principles and assumptions that the DNOs must adhere to in developing the EDCM.
11. The relevant text from Condition 50A is set out in Annex 1 of this report.

² Ofgem (2009) Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements, ref 90/09

The EDCM applies to Designated EHV properties

12. The EDCM will apply to all Designated EHV properties, as defined by Ofgem in Condition 50A.11 of the standard distribution licence.
13. On 25 August 2010, Ofgem modified the distribution licence to change the definition of a Designated EHV property to include certain HV connected properties, and thereby changed the boundary between the EDCM and the CDCM. The common distribution charging methodology (CDCM) is the average charging model used to set charges for HV and LV end users and was implemented on 1 April 2010.
14. The full text of Condition 50A.11 is set out in Annex 1.

Context

15. On 1 October 2008, Ofgem published proposals for a common distribution charging methodology based on LRIC for extra high voltage (EHV) users and a distribution reinforcement model (DRM) for high voltage (HV) and low voltage (LV) users.³
16. Scottish Power Energy Networks and Scottish & Southern Energy Power Distribution raised statutory objections to the licence conditions mandating the LRIC method in these proposals. The Common Methodology Group (CMG) focused its work on the HV/LV part of Ofgem's proposals.
17. The DNOs established the CMG under the auspices of the ENA to take forward work on Ofgem's proposals.
18. On 28 August 2009, DNOs published proposals for the CDCM.⁴ Ofgem accepted these proposals after relevant conditions had been met by DNOs in December 2009. The CDCM came into force on 1 April 2010.
19. On 1 October 2009, licence conditions creating obligations on DNOs to develop and implement the EHV distribution charging methodologies (EDCM), based on FCP or LRIC, came into force. These conditions required DNOs to come forward with proposals for the EDCM by 1 September 2010 for implementation by 1 April 2011.
20. The CMG established three workstreams to develop the EDCM:
 - a) Workstream A steered the development of the power flow modelling;
 - b) Workstream B developed the tariff model and its underlying principles; and
 - c) Workstream C who are looking at reducing volatility, increasing transparency and are investigating the development of long-term fixed products.
21. The following table details the significant milestones since October 2008.

³ Ofgem (2008) Delivering the electricity distribution structure of charges project, ref 135/08

⁴ Energy Networks Association (2009) Report on the draft common distribution charging methodology

Date	Action
1 October 2008	Ofgem published proposals for a common distribution charging methodology based on LRIC for extra high voltage (EHV) users and a distribution reinforcement model (DRM) for high voltage (HV) and low voltage (LV) users. ⁵
20 March 2009	Ofgem announced that it would publish new proposals involving a choice between the LRIC and FCP methods for EHV users. ⁶
1 July 2009	Licence conditions creating obligations on DNOs to develop and implement the common distribution charging methodology (CDCM), based on the HV/LV part of the October 2008 proposals, came into force.
31 July 2009	Ofgem proposed principles for charging EHV users using the FCP/LRIC approaches and a set of licence conditions to mandate their development and implementation. There was no objection from DNOs to these proposals. ⁷
28 August 2009	DNOs published proposals for the CDCM. ⁸ Ofgem accepted these proposals after relevant conditions had been met by DNOs in December 2009. The CDCM came into force on 1 April 2010.
1 October 2009	Licence conditions creating obligations on DNOs to develop and implement the EHV distribution charging methodologies (EDCM), based on FCP or LRIC as specified in the 31 July 2009 document, came into force. These conditions required DNOs to come forward with proposals for the EDCM by 1 September 2010 for implementation by 1 April 2011.
23 April 2010	DNOs published a consultation on options for the allocation of customers between the EDCM and CDCM methodologies (the EDCM/CDCM boundary). Responses were received from all DNOs and from three other stakeholders. We published a summary of responses on 26 May 2010, available from http://2010.energynetworks.org/structure-of-charges-edcm/ .
15 June 2010	Ofgem issued a consultation document on the boundary between the EDCM/CDCM which seeks industry views on the options for defining the boundary to be used to determine whether customers should be subject to the EDCM or the CDCM. ⁹
18 June 2010	DNOs published their first consultation on the proposed EDCM methodology.

⁵ Ofgem (2008) Delivering the electricity distribution structure of charges project, ref 135/08

⁶ Ofgem (2009) Next steps in delivering the electricity distribution structure of charges project, ref 24/09

⁷ Ofgem (2009) Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements, ref 90/09

⁸ Energy Networks Association (2009) Report on the draft common distribution charging methodology

⁹ Ofgem – Modifications of the standard conditions of the electricity distribution licence granted or treated as granted under Section 6 (1) (c) of the Electricity Act 1989, dated 25 August 2010.

Date	Action
25 August 2010	Ofgem modified the distribution licence to change the EDCM/CDCM boundary.
27 August 2010	Ofgem published a letter to the DNOs derogating the DNOs from the requirement to submit the EDCM methodology and illustrative tariffs on 1 September 2010. The letter also set out several requirements for the DNOs to satisfy before submitting the EDCM. ¹⁰
1 September 2010	DNOs published an EDCM information pack containing the results of the development work undertaken as on 1 September 2010.
30 September 2010	Ofgem published a letter to DNOs setting out their decision to revise the date by which DNOs are required to submit the EDCM methodology to 1 April 2011, for implementation by 1 April 2012.
21 December 2010	DNOs publish their second consultation on the proposed EDCM methodology.
11 February 2011	DNOs publish a mini-consultation on LDNO charging under the EDCM.

Arrangements for pre-2005 connected distributed generators

22. The EDCM will apply to all designated EHV properties, including qualifying generators connected before April 2005.
23. Ofgem has decided that the issue of compensation for deep connection charges paid by generators connected before April 2005 is to be unbundled from the calculation of use of system charges, and therefore outside the scope of the EDCM.¹¹
24. Ofgem is currently considering the issue of compensation for pre-2005 connected distributed generators.

Stakeholder involvement

25. The development of the EDCM has been an open process, led by the DNOs through the CMG, which is open to Ofgem and all interested parties. Discussions with Ofgem and with stakeholders have taken place throughout the project.
26. The support and feedback from suppliers, generators, Ofgem, end-users and independent Licensed Distribution Networks Operators (LDNOs) through, in particular, participation in the distribution charging methodologies forum (DCMF) and the CMG's workstream B, is gratefully acknowledged.

¹⁰ Ofgem letter to DNOs, dated 27 August 2010.

¹¹ Ofgem letter – Charges for pre-2005 Distributed Generators' use of DNOs' distribution system – decision on unbundling, dated 23 August 2010.

27. Ofgem representatives have regularly attended CMG and workstream B meetings, and have contributed to the development of the EDCM.
28. The DNOs have consulted stakeholders on a number of specific issues, including through formal consultations, and presentations to the distribution charging methodology forum (DCMF).
29. All consultations and other materials produced by the project are published at <http://2010.energynetworks.org/structure-of-charges-edcm/>.
30. There have been four formal consultations by the DNOs:
 - a) A consultation on the EDCM/CDCM boundary in April 2010; and
 - b) A consultation on the EDCM charging methodology in June 2010.
 - c) A second consultation on the EDCM charging methodology in December 2010.
 - d) A mini-consultation on charging arrangements for LDNOs under the EDCM in February 2011.
31. In addition to these written consultations the DNOs held national workshops for stakeholders and customers on 28 June 2010, 18 November 2010 and 13 January 2011.
32. All DNOs have held regional workshop throughout the project.

Development chronology

33. The June 2010 consultation document contained an initial draft of our proposed methodology for the calculation of EDCM tariffs. We made improvements to the methodology after that, reflecting both consultation responses and further work by the DNOs. Changes made between June 2010 and the September 2010 information paper included:
 - a) Changes in the calculation of marginal charges calculated using the FCP and LRIC methodologies, including splitting these charges into a local and remote element, and the introduction of a cap on such charges;
 - b) The approach to calculating charges for users subject to demand side and generation side management agreements has been further specified;
 - c) Introduction of generation scaling;
 - d) Changes to the method for demand scaling;
 - e) Changes to the way in which transmission exit charges are allocated; and
 - f) Development of the charging method for DNO-to-DNO interconnections, LDNO portfolio tariffs, offshore networks and unlicensed networks.
34. Following the publication of the information report in September 2010, we made further changes to the methodology:

- a) The application of part of the marginal charges calculated using the FCP and LRIC methodologies to in-year consumption units;
 - b) Changes to the method for demand scaling; and
 - c) Sole use assets to be allocated between the import and export tariffs proportionally to import and export capacities respectively (they were previously allocated entirely to the import tariff).
35. We then consulted on the methodology in December 2010. Following the consultation, we have made further changes:
- a) We have removed excess reactive power charges for reactive power flows outside the 1 – 0.95 power factor range;
 - b) Further development of the method to calculate charges for sites subject to demand side management (DSM) or generation side management (GSM) agreements;
 - c) An increase in the number of asset-based allocation categories for demand customers;
 - d) Including a cap and collar for network use factors used in asset based allocations for demand customers; and
 - e) A change in the payment of credits to generators, from all-year units to units generated in the super-red time band only.

Illustrative charges under the EDCM

36. Appendix 1A contains illustrative tariffs for customers, both demand and generation, under the proposed EDCM methodology. These tariffs are illustrative, and are based on data relating to the charging year 2011/2012. If the EDCM is approved, tariffs that will apply in the charging year 2012/13 would be based on input data relating to that charging year.
37. For confidentiality reasons, customer names are not published. Customers interested in finding out more information about their illustrative tariffs should contact their DNO.¹²
38. Appendix 1B contains illustrative LDNO portfolio tariffs that would apply to CDCM customers.
39. Please note that the tariffs in Appendix 1A and 1B are different from the tariffs that will apply during the charging year 2011/12, which are based on the DNOs' current methodology. They are also different from the EDCM tariffs that will eventually apply from April 2012 onwards.
40. The tariffs in Appendix 1A and 1B are for illustrative purposes only and they must not be relied upon for any purpose.

¹² DNO contact details are available from the ENA website at <http://2010.energynetworks.org/edcm-file-storage/2-dno-contact-details/>

Future governance

41. The EDCM will be subject to a governance regime under the distribution connection and use of system agreement (DCUSA). It will be open to all DCUSA parties, and others materially affected (with permission from the Authority) to make proposals to modify and improve the methodology.
42. All DNOs have licence obligations to have in place at all times charging statements in relation to Use of System (UoS) and Connection:
 - a) The Statement of UoS Charging Methodology;
 - b) The Statement of UoS Charges; and
 - c) The Statement of Connection Charging Methodology and Charges.
43. All DNOs also have a requirement to keep the methodologies under review and bring forward proposals to modify those methodologies that they consider better achieve the relevant objectives.
44. This obligation is achieved under the common charging methodology by using a combination of the distribution charging methodology forum (DCMF), the Methodology Issues Group (MIG) which is a DCMF sub-group and the distribution connection and use of system agreement (DCUSA).
45. Broadly speaking, the DCMF is a forum to identify issues and concerns, and the DCUSA is the governance body of the methodology. This process discharges the following licence conditions for (DNOs):
 - a) 50.25 - to meet periodically with others (as defined) to discuss developments in the CDCM;
 - b) 50.27 – to provide timely and efficient process for modifications to the authority (also discharged with DCUSA);
 - c) 50.28 – to provide a review and future modification of the modification arrangements (also discharged with DCUSA); and
 - d) 13A.4(a) – Hold an annual review of the charging methodology (DCMF)
46. Further details about the open governance process are available on the DCMF section of the website of the Energy Networks Association at <http://2010.energynetworks.org/distribution-charging-methodol/>

Project timeline and next steps

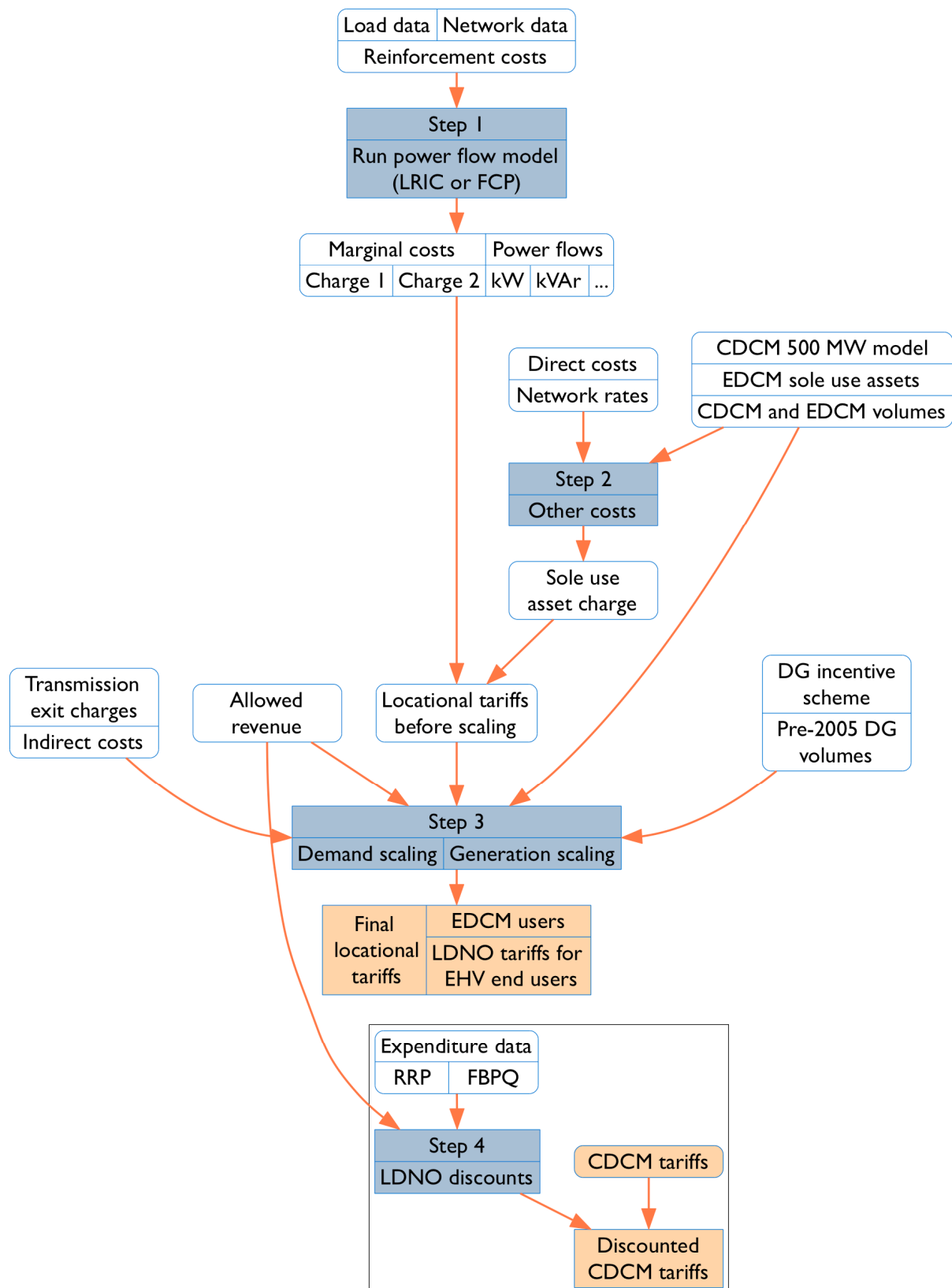
47. The DNOs have scheduled a national workshop on 12 May 2011 to support this submission.
48. Subject to Ofgem approval, the EDCM would come into force on 1 April 2012.

Overview of the EDCM

49. The EDCM method involves four main steps.

50. Step 1 is the application of load flow techniques and the LRIC or FCP methodologies to determine two EDCM tariff elements, known as charge 1 and charge 2:
 - a) Charge 1 represents costs associated with demand-led reinforcement, estimated by reference to power flows in the maximum demand scenario; and
 - b) Charge 2 represents costs associated with generation-led reinforcement, estimated by reference to power flows in the minimum demand scenario.
51. Step 2 involves the allocation of identifiable DNO costs to customers using appropriate cost drivers.
52. Step 3 adds a scaling element to tariffs which is related to the DNOs' allowed revenue.
53. Step 4 uses CDCM tariffs to determine the element of portfolio tariffs to be applied in the case of LDNOs who are supplied from the DNO's network at voltages higher than the scope of CDCM tariffs.
54. Figure 1 provides a diagrammatic overview of the steps involved.

Figure 1 Diagrammatic overview of the EDCM



EDCM tariff components for end users

55. This section sets out the different tariff components that will apply to customers (end users) under the EDCM. Tariff components are the outputs of the EDCM and make up the distribution use of system charges applied to customers.
56. Under the EDCM, a customer is defined as a site as determined in the bilateral connection agreement. However, where a site is a group of connection points that relate to a single bilateral connection agreement, these connection points would be treated as a single customer for charging purposes.
57. The unit of application of EDCM charges is a “tariff”. Each tariff represents an entry in the EDCM model input data sheet, and therefore would have a full set of outputs, i.e. EDCM tariff components.
58. The EDCM recognises two categories of tariffs; import (demand) tariffs and export (generation) tariffs.
59. Each customer may have one tariff associated with it, unless the customer has registered its meters to allow for data about power flows in both directions to be recorded in settlements, in which case separate import and export tariffs will apply.
60. The use of separate tariffs is consistent with the allocation of separate MPANs or MSIDs for import and export, and with the CDCM tariff structure.
61. Tariffs under the EDCM comprise the following individual components:
 - a) Fixed charges (both demand and generation);
 - b) Capacity charges (both demand and generation);
 - c) Exceeded capacity charges (both demand and generation)
 - d) Unit rate charges for consumption at the time of DNO peak (super-red time band) (for demand only); and
 - e) Unit rate credits for generation export at the time of DNO peak (super-red time band).
62. The EDCM tariff components for demand are listed in table 1.

Table 1 Tariff components for import tariffs

Tariff component	Unit	Comments
Fixed charge	p/day	Sole use asset charges for direct operating costs and network rates.
Import capacity charge	p/kVA/day	Reflects the local element of the FCP/LRIC charge 1, pre-allocation of direct operating costs, indirect costs, network rates, transmission exit charges and the demand scaling charge.
Exceeded import capacity charge	p/kVA/day	Charged at the same rate as the import capacity charge (except for sites with demand side management agreements)
Super-red unit charge	p/kWh	Reflects the remote element of the FCP/LRIC charge 1.

63. The EDCM tariff components for generation are listed in table 2.

Table 2 Tariff components for export tariffs

Tariff component	Unit	Comments
Fixed charge	p/day	Reflects sole use asset charge for direct operating costs and network rates.
Export capacity charge	p/kVA/day	Reflects both local and remote elements of the FCP/LRIC charge 2, the generation scaling fixed adder and transmission exit credits for qualifying generators.
Exceeded export capacity charge	p/kVA/day	Charged at the same rate as the export capacity charge (except for sites with generation side management agreements)
Super-red unit credit	p/kWh (negative)	Reflect both local and remote elements of the FCP/LRIC charge 1.

64. The next section details the calculation of the EDCM tariff elements that determine the tariff components described above.

Calculation of EDCM tariff components

65. EDCM tariff components are derived from tariff elements that are calculated within the model.
66. Tariff elements for demand within the EDCM include:
 - a) Marginal charges calculated using the FCP or LRIC methodologies;
 - b) Transmission connection (exit) charges;
 - c) An element relating to the direct operating costs of the DNO;
 - d) An element relating to the indirect operating costs of the DNO;
 - e) An element relating to the business rates (network rates) payable by the DNO; and
 - f) An element relating to scaling, the part of the DNO's allowed revenue that has not been charged using the cost-based charges above.
67. Tariff elements for generation within the EDCM include:
 - a) Marginal charges calculated using the FCP or LRIC methodologies;
 - b) Credits based on FCP or LRIC methodologies;
 - c) Transmission connection (exit) credits;
 - d) An element relating to the direct operating costs of the DNO (for sole use assets only);
 - e) An element relating to the business rates (network rates) payable by the DNO (for sole use assets only); and
 - f) An element relating to generation scaling (this may be positive or negative).
68. The rest of this section describes the method for calculating each of these tariff elements.

Marginal charges from the FCP and LRIC methodologies

69. This section provides an overview of the marginal charges produced using the FCP and LRIC methodologies. See appendix 2 for a detailed description of these methodologies.
70. Both FCP and LRIC methods separate the distribution network into a number of locations.
71. In the case of LRIC, a location is a node on the EHV network, typically a primary substation or an EHV customer (which might be a demand customer or generator).
72. In the case of FCP, a location is a network group at one of three possible levels on the network:

- a) A level 1 network group contains 132 kV and similar circuits;
 - b) A level 2 network group contains 132kV/33kV and similar substations and 33kV and similar circuits; and
 - c) A level 3 network group contains primary substations, e.g. 132kV/11kV or 33kV/11kV.
73. Each tariff in the EDCM model is associated with a LRIC or FCP location.
74. There is some commonality in the nature and interpretation of the outputs from the LRIC and FCP methodologies.
75. Both methods provide the following information for each location:
- a) Charge 1 (£/kVA/year). In the case of LRIC, the charge 1 is broken down into two components, one related to the voltage level of connection (Charge 1 Local) and the other related to all other levels (Charge 1 Remote).
 - b) Charge 2 (£/kVA/year). In the case of LRIC, the charge 2 is broken down into two components, one related to the voltage level of connection (Charge 2 Local) and the other related to all other levels (Charge 2 Remote).
 - c) Active (kW) and reactive (kVAr) flows from generators and to demand in the maximum and minimum demand scenarios. In FCP there can be both generation and demand on the same network group, whereas LRIC requires that either generation or demand be modelled at any single node. The method for deciding whether a node is to be modelled as demand or generation is set out in the LRIC methodology statement in Appendix 2. Thus, the FCP dataset has four kW and four kVAr values for each location (demand and generation, two scenarios), whereas the LRIC dataset has two kW and two kVAr values for each location.
76. Charge 1, if positive, relates to future demand-led reinforcement costs associated with demand at the relevant location. It is therefore expected to drive charges to demand and corresponding credits to generation, where generation can be considered to avoid or defer the need for future demand-led reinforcement.
77. Charge 2, if positive, relates to future generation-led reinforcement costs associated with generation at the relevant location. It is therefore expected to drive charges to generation, where generation can be considered to cause or bring forward the need for future generation-led reinforcement, by offsetting any credits to generation paid on the basis of charge 1.
78. FCP includes, for each location (network group), a link to the “parent location”, if any, i.e. the higher-level network group to which the network group in question is connected. This establishes a hierarchy of network groups with up to three levels. For each tariff, all charge 1 and charge 2 throughout the hierarchy are applied.
79. Some entries in the FCP dataset can be notional hybrid network groups constructed to handle cases where a customer or lower-level network group is supplied out of two different network groups.

80. LRIC includes, for each node, a link to other nodes (if any) supplying the same customer. If any charge 1 or charge 2 is negative, we replace it with zero.

Application of FCP/LRIC charge 1 to demand tariffs

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

For LRIC

$$[\text{p/kWh super-red rate}] = [\text{remote charge 1 } \text{£/kVA/year}] / \text{PF} / [\text{number of hours in the super-red time band in a year}] * 100$$

$$[\text{p/kVA/day capacity charge}] = [\text{local charge 1 } \text{£/kVA/year}] / [\text{days in charging year}] * 100$$

Where:

PF is the power factor of the flow at the point at which the customer is attached in the maximum demand scenario. If the flow at the relevant point in the maximum demand scenario is zero or is generation-dominated, then PF is replaced with 1. This ensures that power factors recorded or assumed for generation flows do not distort the calculation of import charges.

For FCP

$$[\text{p/kWh super-red rate}] = [\text{parent and grandparent network group charge 1 } \text{£/kVA/year}] * (\text{PF} + [\text{average kVAr divided by kVA}] * \text{SQRT}(1 - \text{PF}^2)) / [\text{average kW divided by kVA}] / [\text{number of hours in the super-red time band in a year}] * 100$$

$$[\text{p/kVA/day capacity charge}] = [\text{network group charge 1 } \text{£/kVA/year}] / [\text{days in charging year}] * 100$$

Where:

PF is the power factor of the flow modelled through the relevant network group in the maximum demand scenario.

The average kW divided by kVA and average kVAr divided by kVA figures are forecasts for the charging year, based on data from the most recent regulatory year for which data were available in time for setting charges for the charging year. Specifically, active and reactive power consumptions are averaged over a super-red time band, which is a seasonal time of day period determined by the DNO to reflect the time of peak, and then divided by import capacity (averaged over the same financial year). If the DNO considers that the reactive consumption data relates to export rather than import (e.g. the average kVAr figure exceeds half of the import capacity) then the import capacity in the denominator should be replaced by the export capacity of the same customer. See appendix 4 for details of the super-red time band for each DNO area. The average kVAr divided by kVA is restricted to be such that the combined active and reactive power flows cannot exceed the maximum import capacity. Should the estimated coincidence factor derived from the above equation be negative, then it is set to zero.

Application of FCP/LRIC charge 1 to generation

83. Both elements of charge 1 will apply to generation as a credit, based on the estimated extent to which generation contributes to network security and thereby reduces or defers the need for the type of reinforcement which underpins the calculation of charge 1.
84. We take account of intermittency of generation in providing support to the network, through a parameter which we term “network support factor”. The network support factor, which applies to an export tariff, represents the likelihood that export at that location is providing useful security of supply support for demand in the network group.
85. The network support factor is set to zero if the F factor that is assigned to the generator in the LRIC or FCP methodologies is equal to zero, and set to 1 otherwise. In the FCP and LRIC methodologies described in Appendix 2, the F factor is used to determine the proportion of the generator’s capacity that was taken into account in assessing network security.
86. The credit is calculated on the basis of actual active power export during the relevant DNO’s super-red time period. Export during other times would not qualify for these credits. This is because the benefit provided by generation is felt most when the network is most loaded. This is also consistent with the basis for the calculation of FCP and LRIC charge 1.
87. The generation credit rate is calculated using the formula:

$$[\text{p/kWh generation credit}] = 100 * [\text{network support factor}] * [\text{charge 1 } \text{£/kVA/year}] / [\text{number of hours in the super-red time band}]$$

Where:

Charge 1 £/kVA/year is the sum of both local and remote elements in the case of LRIC and the sum of the local and parent/grandparent charge 1 in the case of FCP.

Application of FCP/LRIC charge 2 to demand

88. We do not apply charge 2 to pay credits to demand.
89. This is based on the assumption that all demand is intermittent, and therefore does not defer or offset the need for generation-led reinforcement.

Application of FCP/LRIC charge 2 to generation

90. We apply all elements of charge 2 to export capacity.
91. The generation charge rate is:

$$[\text{p/kVA/day capacity charge}] = [\text{charge 2 } \text{£/kVA/year}] / [\text{days in charging year}] * 100$$

Where:

Charge 2 £/kVA/year is the sum of both local and remote elements of charge 2 in the case of LRIC and the sum of the local and parent/grandparent charge 2 in the case of FCP.

No application of negative charges

92. Under FCP, charge 1 and charge 2 are either zero or positive.
93. Under LRIC, charge 1 and charge 2 can be negative at some locations. This implies that reinforcement might be avoided by increasing consumption in the maximum demand scenario, or by increasing generation in the minimum demand scenario.
94. Negative charge 1 or charge 2 values are not applied in any demand or generation tariffs.

Demand side management (DSM) and generation side management (GSM)

95. Some EDCM users are subject to demand side management (DSM) or generation side management (GSM) agreements. Users subject to such agreements have interruptible connections and agree to stop or reduce consumption (or production) at the request of the DNO. Such agreements may remove the need for network reinforcement that might have been unavoidable otherwise.
96. For customers with DSM or GSM agreements, we define a concept called “chargeable capacity”, which is equal to the maximum import or export capacity minus the capacity that is subject to restrictions under a DSM or GSM agreement. These restrictions would take into account any seasonal variations built into these agreements.
97. For demand customers with DSM agreements, DSM-adjusted local and remote (or parent and grandparent) elements of the FCP/LRIC charge would be calculated as the product of the ratio of “chargeable capacity” to maximum import capacity and the unadjusted elements of the FCP/LRIC charge. The DSM-adjusted local element of the FCP/LRIC charge 1 would be applied to the maximum import capacity, and the DSM-adjusted remote (or parent and grandparent) element of the LRIC/FCP charge 1 would be applied to units consumed during the super-red time band.

98. For generation customers with GSM agreements, GSM-adjusted FCP/LRIC charges would be calculated as the product of the ratio of chargeable capacity to maximum export capacity and the unadjusted FCP/LRIC charge. The GSM-adjusted FCP/LRIC charge 2 would be applied to the maximum export capacity.

Transmission connection (exit) charges for demand tariffs

99. We will include a separate transmission exit charge for demand tariffs only.

100. A single charging rate, in p/kW/day is calculated as follows:

Transmission exit charging rate p/kW/day = $100 / DC * NGET \text{ charge} / (\text{CDCM system maximum load} + \text{total EDCM peak time consumption}) *$

Where:

DC is the number of days in the charging year.

NGET charge is the forecast annual DNO expenditure on transmission connection point charges in £.

CDCM system maximum load is the forecast system simultaneous maximum load from CDCM users (in kW) from CDCM table 2506.

Total EDCM peak time consumption (in kW) calculated by multiplying the maximum capacity of each user by the forecast peak-time kW divided by forecast maximum kVA of that user (based on available historical data) and aggregating across all EDCM demand.

101. The single p/kW/day charging rate is converted into a p/kVA/day import capacity based charge for each EDCM demand user by multiplying by forecast peak-time kW divided by maximum kVA of that user.

Reactive power charges

102. The EDCM does not include a separate tariff component for any reactive power flows for either demand or generation tariffs.
103. This is because the method used to calculate the LRIC and FCP unit rate charges, applied to active units consumed during the super-red time band, take account of the effect on the network of the customer's power factor (using historical data). Therefore the active power unit rate includes an implicit charge for reactive flows.

Transmission connection (exit) credits for generators

104. We will include in tariffs for generators a capacity-based credit related to transmission exit.
105. Transmission exit credits would be paid to generators that have an agreement with the DNO, the terms of which require the generator, for the purposes of P2/6 compliance, to export power during supergrid transformer (SGT) outage conditions.
106. Such generators are deemed to help avoid asset reinforcements at the GSP, and therefore should be paid a credit in respect of transmission exit charges.

107. The credit would be determined as a uniform £/kVA/year by dividing forecast annual expenditure on transmission connection point charges by the DNO's estimate of overall system maximum load.
108. This £/kVA/year transmission exit credit would be applied only to the capacity that is made available by the generator under the agreement.

Allocation drivers for other tariff elements in the EDCM

109. In addition to charges calculated using the FCP and LRIC methodologies and transmission connection (exit) charges or credits, the EDCM includes tariff elements relating to:
- a) DNO direct operating costs (this includes inspection and maintenance costs, operating expenditure relating to fault repairs and the cost of tree cutting);
 - b) DNO indirect costs. (these are costs that are not directly related to network assets, such as business support costs);
 - c) DNO network rates (these are business rates paid by DNOs); and
 - d) DNO residual revenue.
110. Allowed revenue is the amount of income the DNO agrees with the regulator that it is allowed to recover from its customers to cover its costs over the price control period; in any given year if the charges to customers do not recover the allowed amount then the shortfall or excess is carried forward into the next year. The residual revenue is that part of the DNO's allowed revenue that has not been pre-allocated to demand tariffs using cost-based tariff elements. Residual revenue includes depreciation, return on capital, the cost of incentive schemes etc.
111. EDCM tariff elements are determined using allocation drivers. We use the following allocation drivers in the EDCM:
- a) The value of assets that are for the sole use of a customer (sole use assets). This is relevant to both demand and generation tariffs;
 - b) The value of site-specific shared network assets used by the customer. This is relevant to demand tariffs only;
 - c) The sum of historical consumption at the time of system peak and 50 per cent of maximum import capacity. This is relevant to demand tariffs only; and
 - d) The maximum export capacity. This is relevant to generation tariffs only.
112. Allocation drivers for demand tariffs are used for three purposes:
- a) To split the DNO's total allowed revenue into two parts, one part to be recovered from HV/LV users (through the CDCM) and the other from demand users at higher voltages (the EDCM demand revenue target);
 - b) To allocate cost-based elements to demand and generation customers; and

- c) To allocate the residual revenue in the EDCM demand revenue target to individual demand customers.
- 113. The allocation to individual customers that are driven by the value of sole use assets are charged to demand and generation customers as a fixed charge (in p/day).
- 114. All other allocations are charged to demand customers as a capacity charge (in p/kVA/day).
- 115. The methods used to determine the value of sole use assets and shared site-specific shared network assets are described below.

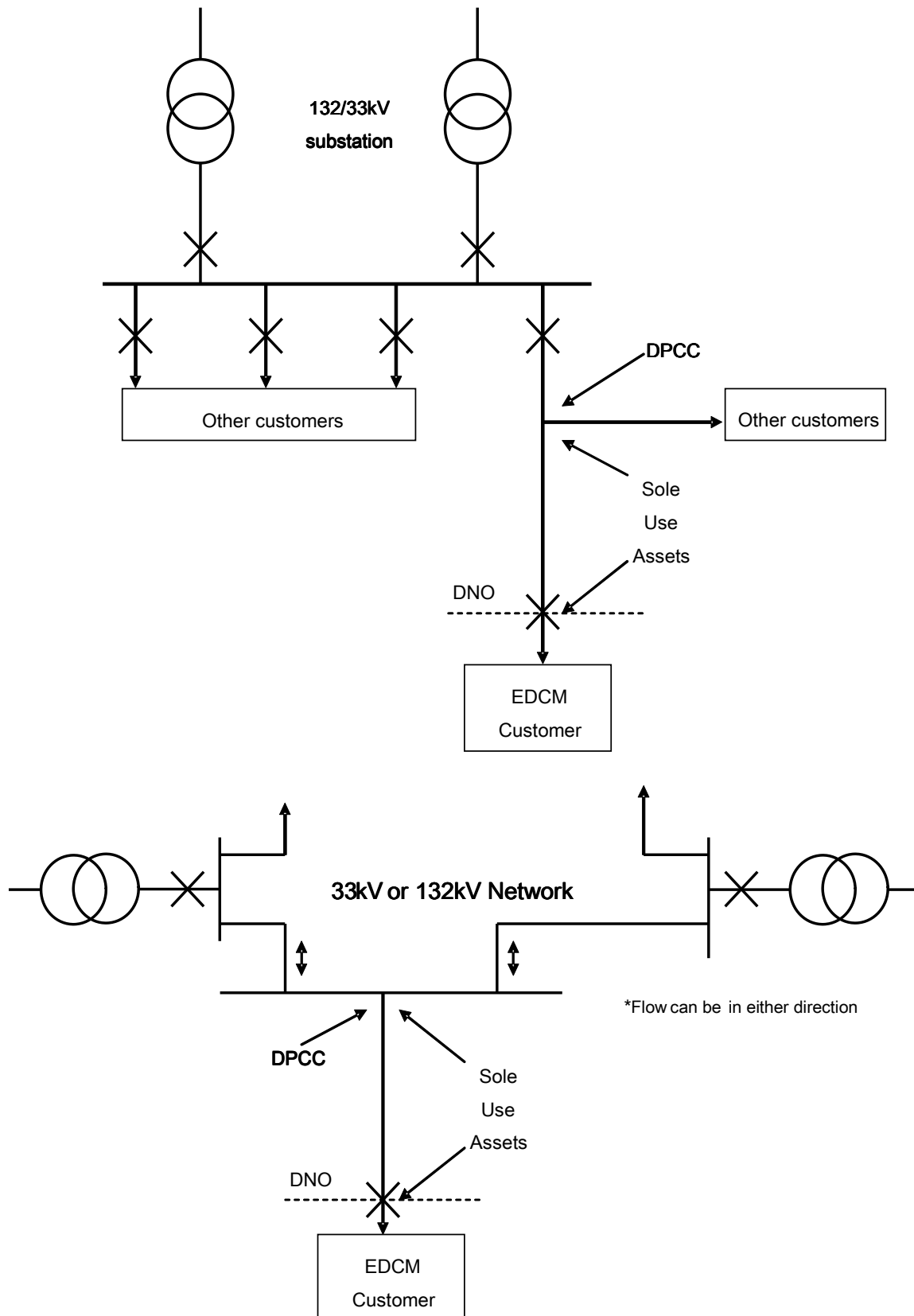
Sole use assets

- 116. The value of a customer's sole use assets used is expressed in the form of a modern equivalent asset value (MEAV) in £.
- 117. Sole use assets are assets in which only the consumption or output associated with a single customer can directly alter the power flow in the asset, taking into consideration all possible credible running arrangements, i.e. all assets between the customer's Entry/Exit Point(s) and the Distribution Point(s) of Common Coupling (DPCC) with the general network are considered as sole use assets.
- 118. The DPCC for a particular single customer is the point on the network where the power flow associated with the single customer under consideration, may under some (or all) possible arrangements interact with the power flows associated with other customers, taking into account all possible credible running arrangements.
- 119. Where a single site has two EDCM tariffs, associated with import and export meter registrations, the sole use assets are allocated between the import and export tariffs proportionally to maximum import and export capacities respectively.
- 120. Where an EDCM site was originally connected as a single customer, and has subsequently split into multiple sites, these sites will continue to be considered as one site for the purposes of determining sole use assets. The sole use asset MEAV will be allocated between these sites in proportion to their maximum import or export capacities.
- 121. Sole use assets for any customer might change when existing customers leave the network, new customers connect to the network or other changes are made to the network.
- 122. One of the issues identified during the development of the methodology is the definition of sole use assets in particular where these were installed for connections and would have been fully paid for under the previous connections policy. If new customers connect to these assets their classification changes from sole use to shared use and no account is taken of the original contribution to the cost of these assets.
- 123. The definition for sole-use assets in the EDCM is based on a technical assessment rather than the commercial boundary of connection. Sole use assets are assets in which only the consumption or output associated with a single customer can directly alter the power flow in the asset, taking into consideration all possible credible running arrangements, i.e. all assets between the customer's Entry/Exit Point(s) and

the Distribution Point(s) of Common Coupling (DPCC) with the general network are considered as sole use assets.

124. Once the Ofgem policy on the application of compensation is clear we will review the proposals (consistent with the Ofgem decision) to accommodate the charge of shared and sole-use assets which are currently excluded from the methodology.
125. Figure 2 contains a stylised network diagram showing the concept of sole use assets.

Figure 2 Sole use assets



Site-specific shared network assets

126. A customer's notional site-specific shared network asset value is the value of network assets that are deemed to be used by that customer, other than sole use assets as defined earlier.
127. The value of notional site-specific shared assets used by each customer is expressed in the form of a modern equivalent asset value (MEAV) in £.
128. First, a voltage level average shared asset value is determined for each EDCM demand customer based on asset values in the DNO's 500 MW model. The voltage level shared asset value is then combined with a site-specific "network use factor" from load flow analysis to determine notional site-specific shared assets.
129. A description of the load flow analysis used in the calculation of the site-specific network use factors is set out in Appendix 2.
130. A detailed description of the method to calculate the notional shared network asset MEAVs using is set out in Annex 2.

Calculation of the EDCM demand revenue target

131. The EDCM demand revenue target is the share of the DNO's allowed revenue (excluding transmission exit charges and net revenue from EDCM generation) that will be recovered from EDCM demand customers.
132. The EDCM demand revenue target will include contributions from EDCM demand users relating to:
 - a) DNO network rates;
 - b) DNO direct operating costs;
 - c) DNO indirect costs;
 - d) DNO residual revenue (allowed revenue minus costs); and
133. The value of contributions from each demand user is determined using the value of site-specific shared assets and sole use assets of that user, relative to the total assets in the model.
134. The total assets in the model is the sum of the following:
 - a) The total notional site-specific shares assets of all EDCM demand users;
 - b) The total sole use assets of all EDCM demand and generation users;
 - c) The total EHV network assets used by HV/LV (CDCM) users; and
 - d) The total HV and LV network and service model assets.
135. The value of sole use assets and HV and LV service model assets are excluded when calculating the contributions relating to DNO residual revenue.

136. The detailed methodology for calculating the EDCM demand revenue target is set out in Annex 3.

Demand scaling

137. Demand scaling is the process by which charges to EDCM demand customers are set so that the forecast notional recovery from demand customers matches the EDCM demand revenue target.
138. Our December consultation set out two alternative approaches for demand scaling under the EDCM:
- a) The site-specific approach; and
 - b) The voltage level average approach.
139. Under the site-specific scaling approach, the allocation of direct operating costs, indirect costs and 80 per cent of the residual revenue is driven by notional site-specific assets (using the network use factor from load flow analysis).
140. Under the voltage level scaling approach, the allocation of these elements is driven by average voltage level assets.
141. The DNOs have decided to adopt the site specific approach to demand scaling. Annex 4 explains the reasons for doing so.
142. Demand scaling involves the following steps:
- a) Allocation of the direct operating cost and network rates elements in the EDCM demand revenue target to individual EDCM demand users on the basis of shared network assets and sole use assets.
 - b) Allocation of the indirect cost element in the EDCM demand revenue target to individual EDCM demand customers in the basis of their forecast consumption at the time of DNO peak (based on historical data) and 50 per cent of maximum import capacity as a p/kVA/day charge.
 - c) Forecasting the notional recoveries from the application of LRIC or FCP charges to EDCM demand users.
 - d) Allocation of 80 per cent of the difference between the EDCM demand revenue target and the sum of charges under (a), (b) and (c) above on the basis of shared network assets (not sole use assets).
 - e) Allocation of 20 per cent of the difference between the EDCM demand revenue target and the sum of charges under (a), (b) and (c) above on the basis of forecast consumption at the time of peak and 50 per cent of maximum import capacity as a p/kVA/day fixed adder.
143. The DNOs' direct operating costs and network rates are considered to be closely linked to network assets, and therefore best allocated using assets (shared and sole use) as the driver.

- 144. DNO indirect costs are not considered to be closely linked to assets, but rather to customer size. As a result, indirect costs are allocated to customers on the basis of a composite proxy for customer size, i.e. 50 per cent of maximum capacity and peak-time consumption.
- 145. The rationale for allocating 80 per cent on the basis of shared network assets and 20 per cent on the basis of a fixed adder is set out in Annex 5.
- 146. The detailed methodology for demand scaling and a stylised example are described in Annex 6.

Sense checking of charges and treatment of outliers

- 147. One of the requirements placed by Ofgem on the DNOs in relation to the EDCM is that charges to customers must pass a “sense check” and be fully justifiable.
- 148. The DNOs believe that, although the proposed EDCM results in fair and cost-reflective charges to the vast majority of customers, there are a few customers whose charges could turn out to be different from what might be considered a reasonable allocation of the DNO’s forward looking business costs.
- 149. Although these “outliers” could occur under both scaling approaches presented in the December consultation, our focus in this section is on DNOs’ proposed site-specific approach.
- 150. Under the EDCM, the allocation of identifiable costs and demand scaling to individual customers is largely determined by the value of network assets that each customer is deemed to use. The other determinants are capacity and consumption at the time of DNO peak.
- 151. In the site-specific approach, power flow analysis is used to match customers and the network assets. The power flow analysis, however, might in some cases indicate usage of network assets that may be affected by wider network design considerations unrelated to the needs of that customer.
- 152. To address this, DNOs have decided to adopt a “cap and collar” approach to tackle the issue of outliers. Under this approach, the cap and collar would apply to the network use factors that in turn determine the value of shared network assets that are deemed to be used by each customer.
- 153. The DNOs have decided that, for a network level, a common cap and collar would be used across all DNO areas.
- 154. The cap and collar would only be applied for the purpose of allocating costs and demand scaling to individual customers, not for determining the overall revenue to be recovered from the EDCM demand customer group.
- 155. Further details of the application of these caps and collars are described in Annex 6.

Sole use asset charges for demand and generation

- 156. Under the EDCM, demand and generation tariffs contain a fixed charge component (in p/day) that represents a use of system charge calculated on the basis of the sole use asset values for that tariff.

157. Sole use asset charges are an allocation of the DNOs' direct operating costs and network rates based on asset values. The same formula is used to calculate sole use asset charges for demand and generation tariffs.
158. Unlike shared network assets, sole use assets do not attract a demand scaling charge. The decision to treat sole use assets differently was made taking into account the DNOs' expected propensity to replace these assets and the extent to which these assets might have been funded through customer contributions.
159. The assumption made is that sole use assets are fully contributed, and on the balance of probabilities these assets would not be replaced at the end of their 40-year accounting life, or these assets would no longer be sole use assets at the end of 40 years, or the customer would have terminated their connection in that time.
160. A description of the method used to calculate sole use asset charges are set out in Annex 6 on demand scaling.

Generation scaling

161. For generation tariffs, the EDCM includes a fixed adder based on export capacity (£/kVA). Generation scaling is entirely separate from demand scaling.
162. Our approach to generation scaling involves the matching of forecast recoveries from the application of the LRIC/FCP charge 2 to generation tariffs to a target revenue from generation. Any shortfall or excess will be made up by applying a fixed adder (£/kVA/year) to export capacities of each generation user.
163. In applying the scaling element to generation tariffs, the overall capacity-based FCP/LRIC charge is restricted to be non-negative.
164. Neither the generation revenue target, nor the resulting fixed adder, has any interaction with generation credits.
165. A full description of the methodology for generation scaling is set out in Annex 7.

Differences between demand and generation charging methodologies

166. Demand and generation charges under the EDCM are fundamentally different, in terms of the application of the FCP/LRIC charge, cost allocation and residual revenue allocation (scaling).
167. The proposed method for the application of FCP/LRIC charges reflect the view that:
 - a) Demand users can cause network reinforcement, therefore the LRIC/FCP charge 1 is applied to demand as a charge to be paid to the DNO;
 - b) Generation users can also cause network reinforcement (during minimum demand conditions), therefore the LRIC/FCP charge 2 is applied to generation as a charge to be paid to the DNO;
 - c) Demand users do not help offset the need for network reinforcement, therefore they do not receive any FCP/LRIC credits;

- d) Generation users (non intermittent only), however, do help offset the need for network reinforcement, therefore receive FCP/LRIC credits based on charge 1; and
 - e) Intermittent generators do not help offset the need for network reinforcement, therefore they do not receive any FCP/LRIC credits.
168. Other tariff elements for demand under the EDCM represent an allocation of elements of the DNOs' allowed revenue. These include:
- a) Direct operating expenditure;
 - b) Network rates;
 - c) Indirect costs; and
 - d) Residual revenue.
169. Generation tariffs do not include charges for these costs, except through sole use asset charges. This reflects the view that the distribution network (other than sole use assets) exists primarily to serve demand users, not generation users.
170. Generation tariffs include an element of generation scaling. Generation scaling is the process of matching the recoveries from the LRIC/FCP charge 2 to a generation revenue target.
171. The generation revenue target is calculated as the sum of the actual cost of the distributed generation incentive (DG incentive) scheme applied to post-2005 connected DG and an estimate of the cost if the O&M element of the DG incentive scheme were applied to pre-2005 DG.
172. The forecast notional recovery from the application of capacity-based FCP/LRIC charges to generation tariffs is set to be equal to this generation revenue target.
173. Generation scaling has no direct interaction with demand scaling.

Application of EDCM tariffs for end users

174. The form of the LC14 charging statements will change as part the implementation of the EDCM. The new statements would be based on a template common to all DNOs, as is the case for CDCM tariffs. A draft statement is attached in Appendix 7. This is subject to approval by Ofgem.

General approach to tariff application

175. The tariff application rules for the EDCM are the same as for the CDCM wherever possible.
176. The part of EDCM portfolio tariffs (for LDNOs and exempt networks) that is based on CDCM tariffs will be billed like CDCM tariffs.

Exceeded capacity charges

177. Where a customer uses additional capacity over and above the maximum import or export capacity without authorisation, the excess will be classed as exceeded capacity.

178. For the purposes of determining capacity used, the following formula would be used for each half hour:

For import tariffs:

$$\text{Import capacity used} = 2 * (\text{SQRT}(\text{AI}^2 + \text{MAX}(\text{RI}, \text{RE})^2))$$

Where:

AI = Import consumption in kWh

RI = Reactive import in kVArh

RE = Reactive export in kVArh

For export tariffs:

$$\text{Export capacity used} = 2 * (\text{SQRT}(\text{AE}^2 + \text{MAX}(\text{RI}, \text{RE})^2))$$

Where:

AE = Import consumption in kWh

RI = Reactive import in kVArh

RE = Reactive export in kVArh

179. For the purposes of calculating exceeded capacity for import tariffs, any reactive flows during half hours when there is no active power import would not be taken into account. Similarly, for export tariffs, any reactive flows during half hours when there is no active power export would not be taken into account.

180. Any reactive flows associated with a site which operates subject to grid code requirements for generation or sites providing voltage control as a requirement of the DNO would not be taken into account when calculating capacity used. This is to reflect the fact that the continuous operation of required voltage control apparatus could lead to reactive power flows that indicate a capacity utilisation that is higher than the maximum import or export capacity associated with that site.

181. For most customers, the exceeded portion of the capacity will be charged at the same rate as the capacity that is within the maximum. This will be charged for the duration of the month in which the breach occurs.

182. Sites subject to DSM or GSM arrangements would normally pay the DSM- or GSM-adjusted capacity charge for capacity usage up to their maximum import or export capacities.

183. If such sites were to exceed their maximum import or export capacities, the exceeded portion of the capacity will be charged at a rate (in p/kVA/day) that would be calculated as though the site had not been subject to DSM or GSM. This will be charged for the duration of the month in which the breach occurs.

Application of tariff components

184. Table 3 summarises the method of application of tariff components for demand.

Table 3 Application of tariff components for import (demand) tariffs

Tariff component	Unit	Application
Fixed charge	p/day	Applied as a fixed charge.
Import capacity charge	p/kVA/day	Applied to the maximum import capacity.
Exceeded import capacity charge	p/kVA/day	Applied to exceeded capacity for the duration of the month in which the breach occurs (except for sites which operates subject to grid code requirements for generation)
Super-red unit rate	p/kWh	Applied to units consumed during the DNO's super-red time band.

185. Table 4 summarises the method of application of tariff components for generation.

Table 4 Application of tariff components for export (generation) tariffs

Tariff component	Unit	Application
Fixed charge	p/day	Applied as a fixed charge.
Export capacity charge	p/kVA/day	Applied to the maximum export capacity.
Exceeded export capacity charge	p/kVA/day	Applied to exceeded capacity for the duration of the month in which the breach occurs.
Generation credit	p/kWh (negative)	Applied to units produced during the DNO's super-red time band.

Network unavailability rebates

186. Network unavailability rebates will be paid for qualifying generators in line with rules defined by Ofgem. We will use the same method as in the CDCM methodology statement.

Tariffs for new customers

187. New customers could connect at any time between the publication of EDCM tariffs for the new charging year and the end of that charging year.
188. If the connection of such customers had been anticipated before the publication of charges, DNOs would have included forecast data relating to the new customer in both the power flow model and the EDCM tariff model. The resulting tariff would be applied to the new customer, on a pro-rata basis if the price is produced during the charging year.
189. If prices need to be produced for new connections that had not been anticipated at the time of calculating EDCM charges for that charging year, we will:
 - a) Seek indicative load profile information from the new customer, failing that, make a reasonable estimate;
 - b) Run the power flow model after including the new customer to produce a full set of charges 1 and 2, including for the new customer;
 - c) Include the new customer's details, including marginal charges from (a) in the EDCM tariff model, to produce a full set of new tariffs;
 - d) Use the tariff relating to the new customer to calculate charges; and
 - e) Charges relating to the current year for existing customers would not change as a result.
190. If a customer were to change their maximum import or export capacity at any time between the publication of EDCM tariffs for the charging year and the end of the charging year, the published tariff rates would continue to apply for the duration of the charging year.

Application of tariffs for interconnected networks

DNO to DNO tariffs

191. In the case of DNO to DNO interconnections, the interconnections would be categorised into four types:
 - a) The interconnector between the DNOs is normally closed (active), and there is an identifiable benefit from the existence of the interconnection to one DNO only. The other DNO does not benefit from the interconnection.
 - b) The interconnector is normally closed (active), and there is either an identifiable benefit to both DNOs, or no clear benefit to either DNO.
 - c) The interconnector is normally open, and the interconnection exists only to provide backup under certain conditions to either DNO.
 - d) All other interconnections between DNOs.
192. In all cases of type (a), the benefitting DNO will be treated as being equivalent to an EDCM user connected to the other DNO's network. The DNO providing the benefit

will calculate and apply an EDCM demand and generation tariff as applicable to the other DNO. Sole use asset charges and generation credits will not apply.

193. In the case of type (b) interconnections, each DNO will treat the other as an EDCM demand customer. Normal EDCM demand user charges, except charges for sole use assets, will apply.
194. Type (c) interconnections are typically covered by special arrangements between DNOs. Use of system charges would be agreed between DNOs and applied outside the EDCM model.
195. In every other case, each DNO charges the other as a normal EDCM demand customer, as with type (b) interconnections.

LDNO charging

196. LDNOs with distribution systems that serve end users that fall within the scope of the CDCM would have their charges based on standard discount percentages applied to the CDCM all-the-way end user tariffs.
 - a) An LDNO with distribution systems that qualifies as a CDCM “Designated Property” according to the definition set out in licence condition 50.10 would be eligible for portfolio discounts calculated using a price control disaggregation model (method M) consistent with the CDCM methodology set out in the distribution connection and use of system agreement (DCUSA).
 - b) An LDNO with distribution systems that qualifies as an EDCM “Designated EHV Property” according to the definition set out in the licence condition 50A.11 would be eligible for discounts calculated using an “extended” price control disaggregation model (extended method M).
197. LDNOs with distribution systems that qualify as an EDCM “Designated EHV Property” could themselves have end users who would fall under the scope of the EDCM. Since the EDCM is a locational charging method, the host DNO would calculate EDCM tariffs at the DNO boundary for each EDCM-like end user on the LDNO’s network. No portfolio discounts would be calculated for such users as the DNO charges would be based only on the specific site’s equivalent use of the DNO network.
198. The criteria for determining whether an LDNO with distribution systems qualifies for discounts calculated using the extended method M model is set out in the distribution licence condition 50A.11(a) and 50A.11(c):

50A.11 For the purposes of this condition, Designated EHV Properties are any of the following:

- (a) Distribution Systems connected to the licensee’s Distribution System at 22 kilovolts or more;
- (b) premises connected to the licensee’s Distribution System at 22 kilovolts or more;

(c) Distribution Systems connected directly to substation assets that form part of the licensee's Distribution System at 1 kilovolt or more and less than 22 kilovolts where the primary voltage of the substation is 22 kilovolts or more and where the Metering Point is located at the same substation; and

(d) premises connected directly to substation assets that form part of the licensee's Distribution System at 1 kilovolt or more and less than 22 kilovolts where the primary voltage of the substation is 22 kilovolts or more and where the Metering Point is located at the same substation.

199. According to the licence condition, whether a LDNO's distribution system qualifies for an extended Method M discount depends on the location of the Metering Point.

200. Condition 1 of the Standard Conditions of the Electricity Distribution Licence states that a Metering Point:

means the point, determined according to the principles and guidance given at Schedule 8 of the Master Registration Agreement, at which a supply of electricity taken into or conveyed from the licensee's Distribution System:

(a) is or is intended to be measured; or

(b) where Metering Equipment has been removed, was or was intended to be measured; or

(c) in the case of an Unmetered Supply, is treated as measured.

201. In practice, it is unlikely that a boundary between a DNO and a LDNO would include a Metering Point as defined in the MRA. The DNOs have asked Ofgem to consider changing the licence condition so that there is clarity in the definition of a Designated EHV Property as far as LDNOs are concerned. Ofgem is currently consulting on options for change.¹³

202. In the interim, and until the licence condition can be changed or clarified by Ofgem, the DNOs propose an alternative practical definition. The following types of LDNO distribution systems would qualify for discounts calculated using the extended method M model:

a) LDNO distribution systems connected to the licensee's Distribution System at 22 kilovolts or more; and

b) LDNO distribution systems connected directly to substation assets that form part of the licensee's Distribution System at 1 kilovolt or more and less than 22 kilovolts where the primary voltage of the substation is 22 kilovolts or more and where the asset ownership boundary is physically located at the same substation

203. Annex 8 describes the methods proposed under the EDCM to calculate the following tariffs for LDNOs with distribution systems that qualify as designated EHV properties:

¹³ Ofgem (2011) Open letter consultation on a proposed modification to the boundary between the Common Distribution Charging Methodology (CDCM) and the EHV Distribution Charging Methodology (EDCM) as set out in the electricity distribution standard licence conditions (SLCs), dated 15 March 2011.

- a) Portfolio discounts for CDCM-like end users using the extended price control disaggregation model; and
- b) EDCM tariffs for EDCM-like end users.

Offshore networks charging

- 204. DNOs will treat offshore networks connected to the DNO as if they were EDCM end users.
- 205. The DNO will apply the EDCM to calculate an import and export charge based on capacity at the boundary and power flow data metered at the boundary.
- 206. Any sole use assets specific to the offshore network would be charged as a p/day sole use asset charge calculated as applicable to a normal EDCM user.
- 207. Both generation and demand scaling will be applied.

DNO to unlicensed networks

- 208. Unlicensed networks have a choice. If they are part of the Total System under the Balancing and Settlement Code with the network open to supply competition, and if they are party to the DCUSA, and have accepted the obligations to provide the necessary data, they can, if they wish, be treated as LDNOs.
- 209. Otherwise, the DNO applies the EDCM to calculate an import and export charge based on capacity and power flow data metered at the boundary. Any sole use assets specific to the unlicensed network would be charged as a p/day sole use asset charge calculated as applicable to a normal EDCM user.

DNO to nested networks

- 210. This refers to a situation where there is more than one level of nesting of licensees (e.g. host DNO→intermediate LDNO→nested LDNO→customer).
- 211. The proposals below are contingent upon the DCUSA being modified to allow a direct charging relationship to be set up between the host DNO and nested LDNO. Potential modifications to do so are being developed by the IDNO/DNO enduring billing group.
- 212. The nested LDNO sets an LLFC for each customer that describes:
 - a) The voltage of connection of the customer's MPAN.
 - b) The voltage of connection of the intermediate LDNO to the host DNO.
- 213. For non-half-hourly data, following aggregation in settlement, the volumes used in the nested network are aggregated (within the P246 report) with volumes on any other networks operated by the nested LDNO which have a boundary voltage to the host DNO equal to the voltage of connection of the intermediate LDNO to the host DNO.
- 214. Consistent with this data aggregation rule, in respect of CDCM-like end users, the host DNO charges (or pays) the nested DNO on the basis of discounted tariffs for the

voltage of connection of the intermediate LDNO to the host DNO, irrespective of the connection of the nested LDNO to the intermediate LDNO. Additional financial flows might exist between the nested LDNO and the intermediate LDNO, which are not governed by the EDCM.

215. For EDCM-like users on the nested LDNO network, the nested LDNO provides adequate data to the intermediate LDNO so that the intermediate LDNO is able to compute appropriate boundary equivalent data at its boundary with the host DNO.
216. The intermediate LDNO provides boundary equivalent data to the host DNO in respect of each of its EDCM users, including the ones connected to the nested LDNO.

Super-red time bands

217. A super-red time band is a seasonal time of day period determined by each DNO to reflect the time of system peak. Appendix 4 provides details on the super-red time band applicable in each DNO area.

Areas of risk

218. Appendix 3 provides details of the generic risks identified and a commentary from each DNO (where appropriate) on any specific areas of risk relating to the implementation of the EDCM.

Portfolio billing for embedded networks

219. Arrangements for portfolio billing are in place, and changes are being developed for new data flows, new data management systems and governance for these systems. These issues will need to be addressed prior to implementation.

How our proposals meet the objectives of the EDCM

220. This section highlights how our proposals meet the objectives and requirements specified in condition 50 of the standard distribution licence conditions.

First relevant objective

50A.7 The first Relevant Objective is that compliance with the EDCM facilitates the discharge by the licensee of the obligations imposed on it under the Act and by this licence.

221. The proposed methodology enables each licensee to levy charges that are consistent with its allowed revenue under the price control, enabling it to finance its activities. The methodology is designed to reflect costs incurred in operating the network, thereby encouraging appropriate customer behaviour and facilitating the discharge by the licensee of its duties to plan and operate an efficient network.

Second relevant objective

50A.8 The second Relevant Objective is that 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.

- 222. The methodology facilitates new entry into supply by introducing a common charging methodology across all 14 licensees, and by standardising tariff application.
- 223. The methodology facilitates new entry into distributed generation (and the associated energy trading or aggregation services) by providing for the payment of credits to reflect the benefits to distribution networks of distributed generation, and by ensuring simplicity and commonality in the application of these credits.
- 224. The methodology addresses a potential risk of distortion to competition in the distribution of electricity by introducing portfolio tariffs for LDNOs.

Third relevant objective

50A.9 The third Relevant Objective is that compliance with the EDCM results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the licensee in its Distribution Business.

- 225. The methodology is designed to allocate costs incurred, or reasonably expected to be incurred, by the licensee in its Distribution Business, in a way that is consistent with the allowed revenue and Ofgem's guidance on these issues.

Fourth relevant objective

50A.10 The fourth Relevant Objective is that, 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.

- 226. The methodology is designed to take into account any changes to the licensee's network and changes in customer characteristics.
- 227. Whilst the introduction of a common methodology inevitably introduces a degree of rigidity, our proposals for governance ensure that, where appropriate, developments in the distribution businesses will be able to be reflected in modification proposals submitted to Ofgem for decision.

Paragraphs 50A.15 to 50A.19

- 228. Condition 50A also specifies five requirements for the development of the EDCM

50A.15 The first requirement is that the EDCM must be developed by the licensee in conjunction with every Associated Licensee.

- 229. The seven DNO groups worked closely together in developing these proposals, through the CMG and its workgroups.

50A.16 The second requirement is that the EDCM must be able to be given effect by the licensee by not later than the Implementation Date.

230. In parallel with developing the methodology, each DNO has been assessing the potential impact on its business and systems. A few areas of risk are identified in appendix 3, and in some cases a derogation from Ofgem might be necessary to achieve full compliance. Subject to that, the DNOs are confident that they can implement the proposals by 1 April 2012.

50A.17 The third requirement is that the EDCM must be submitted by not later than 1 April 2011 for approval by the Authority in accordance with the direction issued by the Authority pursuant to Part J of this condition on 30 September 2010.

231. This submission fulfils this requirement. The contents of this report details the steps we have taken to meet the requirement.

50A.18 The fourth requirement is that a full set of illustrative Use of System Charges for the Regulatory Year 2011/12 which would have resulted from the licensee's compliance with the EDCM if it had been in force under this licence at 1 April 2010 must be submitted to the Authority by not later than 1 April 2011 in accordance with the direction issued by the Authority pursuant to Part J of this condition on 30 September 2010.

232. See appendix 1.

50A.19 The fifth requirement is that during the development of the EDCM and before submitting it to the Authority in accordance with the third requirement, the licensee must have taken all reasonable steps (including, where appropriate, approaching the Authority to discuss how the licensee proposes to address any unforeseen charging implications of the EDCM) to ensure that the EDCM in the form in which it is being developed will be capable of being approved by the Authority in accordance with the requirements of Part B of this condition.

233. This requirement was satisfied through continuous engagement with Ofgem throughout the process, using both Ofgem staff's participation in CMG, workgroups and the Ofgem-facilitated IDNO/DNO working group, as well as ad hoc meetings and correspondence where required.

Justification of EDCM charges

234. Charges to EDCM customers are set with reference to the total revenue that a DNO's price control allows it to collect from its customers.
235. Ofgem regulates the DNOs to protect the interests of present and future consumers. Ofgem sets price controls that prescribe the revenues that each DNO can collect from customers during the period of the control (currently five years).
236. Ofgem determines individual Charge Restriction Conditions (CRC), which are set out in the DNOs' licences, which detail the calculations used to establish levels of revenue that can be collected each year. Once the annual level of revenue is established, DNOs then set charges in accordance with a methodology that has

been approved by the Authority as meeting the Relevant Objectives set out in the appropriate Licence Condition (13, 13A or 13B).

- 237. As CDCM and EDCM charges are calculated independently in separate models, it is necessary to split the total revenue between the two models. Annex 3 on the calculation of the EDCM demand revenue target details how this split is achieved.
- 238. Once the total amount of revenue to be collected from EDCM customers is established, this is divided between the EDCM customers using the approach documented in the section on demand scaling.
- 239. In summary, incremental charges are first established for each customer using LRIC or FCP; other costs which can be directly attributed using an appropriate driver are then added; and, finally, any residual 'scaling' required to balance the charges to the EDCM share of allowed revenue is allocated on the basis of site-specific assets and customer capacity and peak-time consumption.
- 240. This is consistent with the DNOs' intention of allocating as much of the total costs as possible using appropriate cost drivers, and, where no suitable driver exists, adopting a simple, transparent and non-distorting method of scaling.
- 241. DNOs are content that their method of establishing the charges that are required to be collected from EDCM users is justifiable on the basis that it meets the policy aim of encouraging efficient network development through forward looking cost signals.
- 242. Throughout the development process the DNOs have made reasonable endeavours to ensure that the EDCM complies with competition law.
- 243. Annex 4 describes the rationale for our choice of demand scaling approach. The section on sense checking of charges and treatment of outliers describes the steps that we have taken to address outliers, i.e. specific instances where charges are deemed to be either excessive or too low.
- 244. Appendix 8 sets out commentary from individual DNOs on the justification of charges in their areas.

Significant deviations from Ofgem specifications

- 245. Appendix 9 sets out a discussion of the areas of the proposed methodology that the DNOs consider represent significant deviations from Ofgem's original specifications for the EDCM.¹⁴

Year-on-year price stability

- 246. Appendix 5 contains a discussion of the potential year-on-year volatility in tariffs arising out of the EDCM.

¹⁴ Ofgem (2009) Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements, ref 90/09

Glossary

<i>Term</i>	<i>Explanation</i>
Allowed Revenue	The amount of money that the DNO party is permitted to recover from charges that it levies for the services it provides.
CDCM	The common distribution charging methodology. (The average charging model used for setting charges for high-voltage and low-voltage connections.)
Charging year	The financial year (12 month period ending on a 31 st March) for which charges and credits are being calculated.
Diversity allowance	The extent, expressed as a percentage, to which the sum of the maximum load across all assets in the modelled network level is expected to exceed the simultaneous maximum load for the network level as a whole.
EDCM	One of the distribution charging methodologies (FCP or LRIC) for higher voltage users specified in Ofgem's 31 July 2009 document.
EHV	In this document, EHV normally refers to nominal voltages of at least 22kV.
Embedded network	An embedded distribution network operated by an LDNO.
FBPQ	Forecast business plan questionnaire, a dataset produced by each regional distribution network operator for Ofgem as part of the price control review.
GSP	Grid supply point: where the distribution network is connected to a transmission network, except an offshore transmission network.
HV	Nominal voltages of at least 1kV and less than 22kV.
kV	Kilovolt (1,000 Volts): a unit of voltage.
kVA	Kilo Volt Ampere: a unit of network capacity.
kVAr	Kilo Volt Ampere reactive: a unit of reactive power flow. The network capacity used by a flow of A kW and B kVAr is $\text{SQRT}(A^2+B^2)$ kVA.
kVArh	kVA reactive hour: a unit of total reactive power flow over a period of time. Reactive power meters usually register kVArh.
kW	Kilowatt (1,000 Watts): a unit of power flow.
kWh	Kilowatt hour: a unit of energy. Meters usually register kWh.

<i>Term</i>	<i>Explanation</i>
LDNO	Licensed distribution network operator. This refers to an independent distribution network operator (IDNO) or to a distribution network operator (DNO) operating embedded distribution network outside its distribution service area.
Licensee	The distribution network operator using this methodology to set use of system charges for its network.
LV	Nominal voltages of less than 1kV.
MVA	Mega Volt Ampere (1,000 kVA): a unit of network capacity.
MW	Megawatt (1,000 kW): a unit of power flow.
MWh	Megawatt hour (1,000 kWh): a unit of energy. Energy trading is usually conducted in MWh.
Network level	The network is modelled as a stack of circuit and transformation levels between supplies at LV and the transmission network. A network level is any circuit or transformation level in that stack. An additional network level is used for transmission exit.
Ofgem's 1 October 2008 document	"Delivering the electricity distribution structure of charges project", Ofgem, 1 October 2008, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/ .
Ofgem's 20 March 2009 document	"Next steps in delivering the electricity distribution structure of charges project", Ofgem, 20 March 2009, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/ .
Ofgem's 31 July 2009 document	"Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements", Ofgem, 31 July 2009.
Power factor	The ratio of energy transported (kW) to network capacity used (kVA).
Portfolio tariff	A tariff for use of the network by another licensed distribution network operator where charges are linked to flows out of/into the other licensed distribution network from its end users or further nested networks.
RRP	Regulatory reporting pack, a dataset produced each year by each regional distribution network operator for Ofgem.
Settlement period	One of 46, 48 or 50 consecutive periods of a half hour starting at 0:00 UK clock time on each day.
Standard distribution licence conditions	The standard conditions of the electricity distribution licence that have effect under section 8A of the Electricity Act 1989 (introduced by section 33 of the Utilities Act 2000).

<i>Term</i>	<i>Explanation</i>
System simultaneous maximum load	The maximum load for the GSP Group as a whole.
Unit	Where the context permits, the word unit refers to kWh.
Unit rate	A charging or payment rate based on units distributed or units generated. Unit rates are expressed in p/kWh. Tariffs applied to multi-rate meters and/or using several time bands for charging have several unit rates.

Annex 1: Condition 50A of the Standard Distribution Licence Conditions

247. Condition 50A, introduced into the standard distribution licence conditions by Ofgem specifies four relevant objectives for the EDCM:

50A.7 The first Relevant Objective is that compliance with the EDCM facilitates the discharge by the licensee of the obligations imposed on it under the Act and by this licence.

50A.8 The second Relevant Objective is that 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.

50A.9 The third Relevant Objective is that compliance with the EDCM results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the licensee in its Distribution Business.

50A.10 The fourth Relevant Objective is that, 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.

248. Condition 50A also defines a Designated EHV property:

50A.11 For the purposes of this condition, Designated EHV Properties are any of the following:

(a) Distribution Systems connected to the licensee's Distribution System at 22 kilovolts or more;

(b) premises connected to the licensee's Distribution System at 22 kilovolts or more;

(c) Distribution Systems connected directly to substation assets that form part of the licensee's Distribution System at 1 kilovolt or more and less than 22 kilovolts where the primary voltage of the substation is 22 kilovolts or more and where the Metering Point is located at the same substation; and

(d) premises connected directly to substation assets that form part of the licensee's Distribution System at 1 kilovolt or more and less than 22 kilovolts where the primary voltage of the substation is 22 kilovolts or more and where the Metering Point is located at the same substation.

249. Condition 50A also places some restrictions on the EDCM methodology:

50A.12 The licensee must choose and develop an EDCM that conforms to such principles and assumptions as have been specified by the Authority for the purposes of this condition under one of the following two descriptions:

(a) the methodology described as the long run incremental cost methodology, as detailed in a decision of the Authority dated 31 July 2009; or

(b) the methodology described as the forward cost pricing methodology, as detailed in a decision of the Authority dated 31 July 2009.

50A.13 If the Authority considers it necessary for the purposes of this condition to materially vary any of the principles and assumptions referred to in paragraph 50A.12, it may do so at any time before the Implementation Date in a direction given to the relevant Associated Licensees following consultation with them.

250. Condition 50A also states that the EDCM must meet the following requirements:

50A.15 The first requirement is that the EDCM must be developed by the licensee in conjunction with every Associated Licensee.

50A.16 The second requirement is that the EDCM must be able to be given effect by the licensee by not later than the Implementation Date.

50A.17 The third requirement is that the EDCM must be submitted by not later than 1 April 2011 for approval by the Authority in accordance with the direction issued by the Authority pursuant to Part J of this condition on 30 September 2010.

50A.18 The fourth requirement is that a full set of illustrative Use of System Charges for the Regulatory Year 2011/12 which would have resulted from the licensee's compliance with the EDCM if it had been in force under this licence at 1 April 2010 must be submitted to the Authority by not later than 1 April 2011 in accordance with the direction issued by the Authority pursuant to Part J of this condition on 30 September 2010.

50A.19 The fifth requirement is that during the development of the EDCM and before submitting it to the Authority in accordance with the third requirement, the licensee must have taken all reasonable steps (including, where appropriate, approaching the Authority to discuss how the licensee proposes to address any unforeseen charging implications of the EDCM) to ensure that the EDCM in the form in which it is being developed will be capable of being approved by the Authority in accordance with the requirements of Part B of this condition.

Annex 2: Calculation of shared asset MEAVs

251. We calculate the value of shared network assets used by each demand user as set out below.
252. Five levels are defined for the network's assets:
- a) Level 1 comprises 132 kV circuits.
 - b) Level 2 comprises substations with a primary voltage of 132 kV and a secondary voltage of 22 kV or more.
 - c) Level 3 comprises circuits of 22 kV or more but less than 132 kV.
 - d) Level 4 comprises substations with a primary voltage of 22 kV or more but less than 132 kV and a secondary voltage of less than 22 kV.
 - e) Level 5 comprises substations with a primary voltage of 132 kV and a secondary voltage of less than 22 kV.
253. In some cases, it might be appropriate to treat 66 kV equipment as being equivalent to 132 kV equipment and allocate customers to categories accordingly.
254. EDCM customers are split into 15 categories based on the parts of the EHV network they are deemed to use. This is based on the distribution point of common coupling, defined as the point at which the sole use assets meet the rest of the distribution network. The distribution point of common coupling might be at a different voltage than the customer's supply, and might also be at a different voltage than the voltage of connection when the customer was connected.

Table 5 Categorisation of EDCM customers

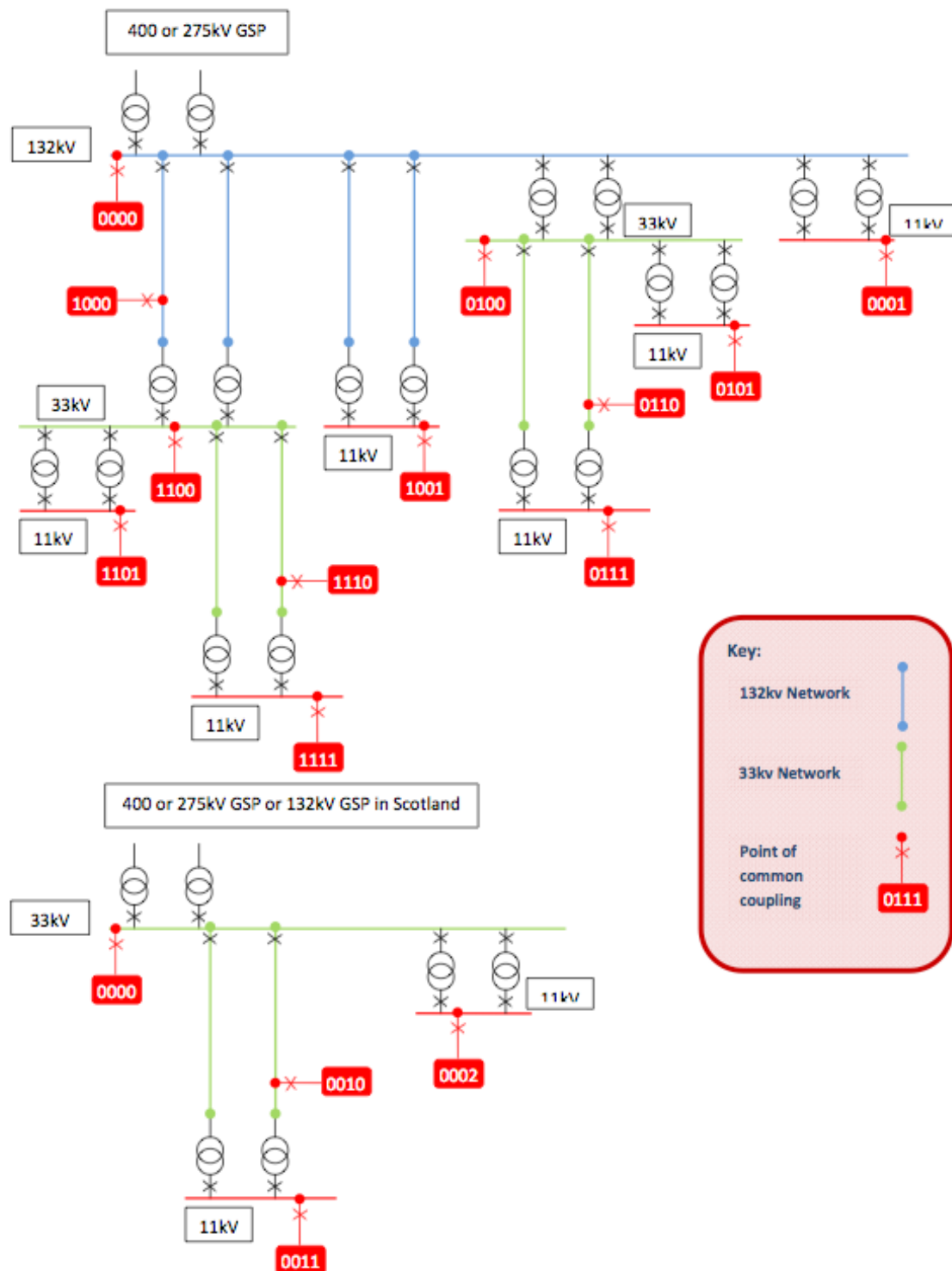
Category	Definition
Category 0000	Point of common coupling at the GSP, whether the GSP is shared or not.
Category 1000	In England or Wales only, point of common coupling at a voltage of 132 kV, unless the customer qualifies for category 0000.
Category 1100	Point of common coupling at 22 kV or more on the secondary side of a substation where the primary side is attached to a 132 kV circuit.
Category 0100	Point of common coupling at 22 kV or more, but less than 132 kV, on the secondary side of a substation where the primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.

Category 1110	Point of common coupling at a voltage of 22 kV or more, but less than 132 kV, not at a substation, fed from a substation whose primary side is attached to a 132 kV distribution circuit.
Category 0110	Point of common coupling at a voltage of 22 kV or more, but less than 132 kV, not at a substation, fed from a substation whose primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.
Category 0010	Point of common coupling at a voltage of 22 kV or more, but less than 132 kV, fed from a GSP with no intermediate transformation.
Category 0001	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation where the primary side is attached at 132 kV to a co-located GSP with no circuit.
Category 0002	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation where the primary side is attached at 22 kV or more but less than 132 kV, to a co-located GSP with no circuit.
Category 1001	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is attached to a 132 kV distribution circuit.
Category 0011	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed from a GSP with no intermediate transformation.
Category 0111	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed through a distribution circuit from a substation whose primary side is attached at 132 kV to a co-located GSP with no circuit.
Category 0101	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed from the secondary side of a co-located substation whose primary side is attached at 132 kV to a co-located GSP with no circuit.
Category 1101	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed from the secondary side of a co-located substation whose primary side is attached to a 132 kV distribution circuit.

Category 1111	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed through a distribution circuit from a substation whose primary side is attached to a 132 kV distribution circuit.
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255. All references to GSP in the table above relate to interconnections with the main interconnected onshore transmission network.
256. The figure overleaf provides examples of customers who might be placed in each of the categories described above.

Customer Categories



257. The model will then estimate the use of each network level by each EDCM demand customer according the rules set out in the following table.

EDCM customers in category	Level 1	Level 2	Level 3	Level 4	Level 5
Category 0000	Zero	Zero	Zero	Zero	Zero
Category 1000	Capacity kVA	Zero	Zero	Zero	Zero
Category 1100	Peak-time active kW	Capacity kVA	Zero	Zero	Zero
Category 0100	Zero	Capacity kVA	Zero	Zero	Zero
Category 1110	Peak-time active kW	Peak-time active kW	Capacity kVA	Zero	Zero
Category 0110	Zero	Peak-time active kW	Capacity kVA	Zero	Zero
Category 0010	Zero	Zero	Capacity kVA	Zero	Zero
Category 0001	Zero	Zero	Zero	Zero	Capacity kVA
Category 0002	Zero	Zero	Zero	Capacity kVA	Zero
Category 1001	Peak-time active kW	Zero	Zero	Zero	Capacity kVA
Category 0011	Zero	Zero	Peak-time active kW	Capacity kVA	Zero
Category 0111	Zero	Peak-time active kW	Peak-time active kW	Capacity kVA	Zero
Category 0101	Zero	Peak-time active kW	Zero	Capacity kVA	Zero
Category 1101	Peak-time active kW	Peak-time active kW	Zero	Capacity kVA	Zero
Category 1111	Peak-time active kW	Peak-time active kW	Peak-time active kW	Capacity kVA	Zero

258. Category 0000 demand users are deemed not to use any network assets other than sole use assets.

259. An average network asset value per kVA (in £/kVA) is calculated in respect of each network level. The average network asset value for the network level of connection is based on the maximum capacity of the user, and for network levels above on consumption at peak time.

$$\text{Average network asset value for capacity at level L (£/kVA)} = \text{NAR}_L * \text{AE} / (1 + D_L)$$

$$\text{Average network asset value for demand at level L (£/kVA)} = \text{NAR}_L * D * \text{LAF}$$

Where:

NAR_L is the network asset rate at level L in £/kW based on the 500 MW model.

AE is the active power equivalent of capacity adjusted to transmission (in kW/kVA). This is calculated by multiplying the power factor in the 500 MW model by the loss adjustment factor to transmission (from CDCM table 2004) for that customer category.

D_L is the diversity allowance from the level exit to the GSP group (from CDCM table 2611).

D is the peak time active power consumption adjusted to transmission in (kW/kVA). This is calculated as the historical peak-time kW divided by historical maximum kVA.

LAF is the loss adjustment factor to transmission (from CDCM table 2004) for that customer category.

260. The average network asset values calculated above are voltage level averages. That is, they are the same for every demand user that used any assets at all at that level.

261. To calculate site-specific asset values, we combine the voltage level averages with network use factors for each user. Details of the load flow methodology used to determine network use factors is described in Appendix 2.

262. Again, separate site-specific asset values per kVA (in £/kVA) is calculated in respect of each network level. The asset value for the network level of connection is based on the maximum capacity of the user, and for network levels above on consumption at peak time.

$$\text{Site-specific asset value for capacity at level L (£/kVA)} = \text{NU}_L * \text{Average network asset value for capacity at level L (£/kVA)}$$

$$\text{Notional asset value for demand at level L (£/kVA)} = \text{NU}_L * \text{Average network asset value for demand at level L (£/kVA)}$$

Where:

NU_L is the network use factor for that user at level L, representing the proportion of the average 500 MW model assets that the user is deemed to use at that level.

Average notional asset value for capacity at level L is the voltage level average calculated as described earlier.

Average notional asset value for demand at level L is the voltage level average calculated as described earlier.

263. The asset values calculated above may be interpreted as the value of assets at each network level that are required to serve each kVA (capacity or demand) of that customer.
264. Network use factors for import tariffs of a mixed import-export site that is generation-dominated are set to default values. These default values are equal to the “collars” for each network level calculated as described in Annex 6 on demand scaling. Generation-dominated sites are determined according to the rules set out in the LRIC methodology to determine whether a location is to be modelled as a generation site. DNOs implementing the FCP methodology would use the same rules to identify generation-dominated sites.
265. The total value of the site-specific shared assets required to serve each demand user is calculated according to the formula:

$$TNA = NAC + NAD$$

Where:

TNA is the total site-specific network assets in £/kVA required to serve a demand user.

NAC is the site-specific asset value in £/kVA for capacity for that demand user aggregated across all levels.

NAD is the site-specific asset value in £/kVA for demand for that demand user aggregated across all levels.

266. Total site-specific shared assets for all EDCM demand is the aggregate value (in £) of all site-specific shared assets for EDCM demand users. This is calculated by multiplying NAC and NAD by the import capacities and historical consumption at peak for each customer, and then aggregating across all EDCM demand.
267. Two values of site-specific asset values are calculated for each demand customer. One value is calculated using the “raw” network use factors determined using the power flow method. This value is used to determine the EDCM demand revenue target.
268. The other value is calculated by applying network use factors that have been subjected to a cap and collar. This value is used to determine the allocation of elements of the demand revenue target to individual demand customers. Further details are provided in the annex 6 on demand scaling.

Annex 3: Calculation of the EDCM demand revenue target

269. This annex describes the method used to calculate the EDCM demand revenue target.

270. A single contribution rate for network rates is calculated for all EDCM demand users as follows:

Network rates contribution rate (per cent) = $NR / (\text{Total site-specific assets} + \text{Total EDCM sole use assets} + \text{EHV assets} + \text{HV and LV network assets} + \text{HV and LV service model assets})$

Where:

NR is the total DNO expenditure on network rates.

Total site-specific assets is the aggregate value (in £) of all notional site-specific assets for EDCM demand users. These asset values are calculated using un-adjusted network use factors.

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM users (demand and generation).

EHV assets is the aggregate EHV assets in the CDCM model.

HV and LV network assets from the CDCM model.

HV and LV service model assets from the CDCM model.

271. To calculate the contribution rates for direct operating costs and indirect operating costs, we take into account possible differences in operating expenditure intensity between HV/LV and EHV assets.

272. We have performed the following calculation:

- a) Using Regulatory Reporting Pack (RRP) data for each DNO, calculate the proportion of direct operating expenditure and faults which fall within the 132kV or EHV network levels.
- b) Using the same data as in the price control disaggregation models used for LDNO tariffs under the CDCM, calculate the proportion of assets which fall within the 132kV or EHV network levels.
- c) Divide (a) by (b) for each DNO.

273. The results from this calculation range from 0.27 to 1.09 with an average of 0.68 for all DNOs.

274. We propose to use this calculation as the basis for an assumption that the asset based charging rate under the EDCM should be set on the basis that each £1 million of EHV assets only receives 68 per cent of the allocation of direct and indirect expenditure that £1 million of HV/LV assets would get.

275. A single contribution rate for direct operating costs is calculated for all EDCM demand users as follows:

Direct operating costs contribution rate (per cent) = $\text{DOC} / (\text{Total site-specific assets} + \text{Total EDCM sole use assets} + \text{EHV assets} + (\text{HV and LV network assets} + \text{HV and LV service model assets}) / 0.68)$

Where:

DOC is the total DNO expenditure on direct operating costs.

Total site-specific assets is the aggregate value (in £) of all site-specific assets for EDCM demand users. These asset values are calculated using un-adjusted network use factors.

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM users (demand and generation).

EHV assets is the aggregate EHV assets in the CDCM model.

HV and LV network assets from the CDCM model.

HV and LV service model assets from the CDCM model.

0.68 is the operating intensity factor.

276. A single contribution rate for indirect costs is calculated for all EDCM demand users as follows:

Indirect costs contribution rate (per cent) = $\text{INDOC} / (\text{Total site-specific assets} + \text{Total EDCM sole use assets} + \text{EHV assets} + (\text{HV and LV network assets} + \text{HV and LV service model assets}) / 0.68)$

Where:

INDOC is the total DNO expenditure on indirect costs.

Total site-specific assets is the aggregate value (in £) of all site-specific assets for EDCM demand users. These asset values are calculated using un-adjusted network use factors.

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM users (demand and generation).

EHV assets is the aggregate EHV assets in the CDCM model.

HV and LV network assets from the CDCM model.

HV and LV service model assets from the CDCM model.

0.68 is the operating intensity factor.

277. Next, a residual revenue contribution rate is calculated as follows:

Residual revenue contribution rate (per cent) = $(AR - DOC - INDOC - NR - GCN) / (\text{Total site-specific assets} + \text{EHV assets} + \text{HV and LV network assets})$

Where:

AR is the DNO total allowed revenue excluding transmission exit charges in £/year

DOC is the total DNO expenditure on direct operating costs.

INDOC is the total DNO expenditure on indirect costs.

NR is the total DNO expenditure on network rates.

GCN is the total forecast net revenue from the application of EDCM charges and credits to EDCM generation.

Total site-specific assets is the aggregate value (in £) of all site-specific assets for EDCM demand users. These asset values are calculated using un-adjusted network use factors.

EHV assets is the aggregate EHV assets in the CDCM model.

HV and LV network assets from the CDCM model.

278. The contribution rates for network rates, direct costs, indirect costs and residual revenue is converted into a £/year import capacity based contribution and a sole use asset MEAV based contribution for each EDCM demand user.

Import capacity based contribution for each user = $TNA * (NR \text{ rate} + DOC \text{ rate} + INDOC \text{ rate} + \text{residual revenue rate}) * \text{import capacity}$

Where:

TNA is the total site-specific assets (£/kVA) for that demand user. These asset values are calculated using un-adjusted network use factors.

NR rate is the network rates contribution rate in per cent.

DOC rate is the direct operating costs contribution rate in per cent.

INDOC rate is the indirect costs contribution rate in per cent.

Residual revenue rate is the residual revenue contribution rate in per cent.

Import capacity is the maximum import capacity in kVA for that demand user.

279. The sole use asset MEAV based contribution in £/year is calculated as follows:

Sole use asset based contribution = $S * (NR \text{ rate} + DOC \text{ rate} + INDOC \text{ rate})$

Where

S is the MEAV of sole use assets of that user.

NR rate is the network rates charge rate in per cent.

DOC rate is the direct operating costs charge rate in per cent.

INDOC rate is the indirect costs charge rate in per cent.

280. We aggregate the target contributions from import capacity and sole use assets across all EDCM demand users.
281. The aggregate EDCM demand revenue target is calculated as the sum, across all EDCM demand, of the contributions based on import capacities and sole use assets.

Annex 4: Rationale for our choice of demand scaling approach

282. Our December consultation set out two alternative approaches for demand scaling under the EDCM:
- a) The site-specific approach; and
 - b) The voltage level average approach.
283. The DNOs have decided to adopt the site specific approach to demand scaling. This annex explains the reasons for doing so.
284. The DNOs have faced several, sometimes conflicting, objectives while trying to develop the EDCM.
285. The primary objective of the EDCM, set by Ofgem, is to develop forward-looking charges that encourage efficient network investment going forward.
286. The EDCM, through the FCP and LRIC methodologies, attempts to meet this objective through marginal charges that are higher in congested areas of the network. These charges are calculated under certain assumptions for growth in demand (and generation) over the network.
287. The DNOs are also under a general responsibility, to ensure that charges to customers are consistent with a fair and reasonable allocation of their business costs (represented in the EDCM by their allowed revenue).
288. The DNOs also need to ensure that their actions do not restrict, distort or prevent competition in the business of transmission and distribution of electricity.
289. The method for demand scaling must meet these objectives by ensuring that the DNOs recover a fair allocation of their allowed revenue from EDCM demand customers, while preserving the signals from the LRIC/FCP charging element.
290. The two demand scaling approaches described in the December consultation document use different allocation drivers to allocate different elements of the EDCM demand revenue target.
291. Table 6 provides an overview of the allocation drivers used under both approaches.

Table 6 Allocation drivers under the two scaling approaches

Tariff element	Site-specific scaling approach	Voltage level scaling approach
Direct operating costs	Notional site-specific shared assets and sole use assets.	Average voltage level shared assets and sole use assets.
Network rates	Notional site-specific shared assets and sole use assets.	Average voltage level shared assets and sole use assets.
Indirect costs	Sum of historical consumption at the time of peak and 50 per cent of maximum import capacity.	Sum of historical consumption at the time of peak and 50 per cent of maximum import capacity.
80 per cent of residual revenue	Notional site-specific shared assets and sole use assets.	Average voltage level shared assets and sole use assets.
20 per cent of residual revenue	Sum of consumption at the time of peak and 50 per cent of maximum import capacity.	Sum of consumption at the time of peak and 50 per cent of maximum import capacity.

292. First, we look at the objective that charges should represent a fair allocation of forward-looking business costs.
293. The site-specific scaling approach, by using notional site-specific asset values to allocate some tariff elements, takes into account individual customers' usage of network assets.
294. To illustrate this point, let us consider two identical EDCM demand customers, both supplied using 33 kV circuits, which in turn originates from a single 132/33 kV substation on the DNO's network.
295. Customer 1 is supplied by 1 km of 33 kV cable from the 132/33 kV substation. Customer 2 is located further away from the same substation, and is therefore supplied by 5 km of 33 kV cable from that substation.
296. The site-specific scaling approach takes this difference in cable length into account while calculating asset values, which in turn affects the allocation of direct operating costs, network rates and 80 per cent of the residual revenue. Being identical in every other way, this means that the allocation of these elements to customer 1 is a fifth of that to customer 2.
297. The voltage level scaling approach ignores the difference in cable length. It assumes that both customers use the average length of 33 kV cable (3 km in this simple example). Being identical in every other way, this means that both customers face exactly the same allocation of direct costs, network rates and residual revenue.
298. If customer 1, instead of being supplied from the same 132/33 kV substation, had been supplied directly from a National Grid grid supply point (GSP) through 132 kV circuits, the allocation would turn out different.

299. Again, let us assume that the two customers are identical in every other way.
300. The site-specific scaling approach takes into account the fact that customer 1 does not use the 132/33 kV substation and 33 kV circuits. It only looks at the actual length of 132 kV circuits used. The allocation of cost elements reflects this.
301. The voltage level scaling approach also takes into account the fact that customer 1 does not use the 132/33 kV substation and 33 kV circuits. When it comes to the length of 132 kV circuits used, it takes the average length of 132 kV circuits on the network.
302. This simple example illustrates the difference between the two approaches in terms of achieving cost reflectivity in charges. The site-specific scaling approach takes a detailed granular view of network asset usage in allocating costs, whereas the voltage level approach takes a less granular, more averaged view.
303. Under the assumption that network asset usage, and our proposed method for determining that usage, represents a fair method of allocating part of the DNOs' forward-looking business costs, the site-specific scaling approach is considered as producing charges that are more cost-reflective.
304. The DNOs also have licence obligations to develop forward-looking charges that encourage efficient network investment going forward. We now look at how well the two approaches help meet this objective.
305. To do this, we start with the assumption that marginal charges from the FCP and LRIC methodologies provide the appropriate signals in terms of efficient future network investments.
306. Let us now look at an example with two identical 33 kV demand customers connected to the different 132/33 kV substations on the network. Customer 1 is connected using 1 km of 33 kV cable from its substation, whereas customer 2 is connected using 5 km of 33 kV cable from the other substation.
307. Let us assume that the FCP/LRIC marginal charges are higher (in £/kVA) for customer 1 than for customer 2. This reflects the fact that the substation serving customer 1 is closer to its capacity, and is therefore predicted to need reinforcement sooner, compared to the substation serving customer 2.
308. Under both scaling approaches, the FCP/LRIC charges are charged in addition to an asset-based allocation of some other costs.
309. Under the voltage level scaling approach, the two customers (being identical in terms of their capacity and demand) would face the same asset-based allocation of costs. The difference between their final charges would be driven by the difference between their FCP/LRIC charges. Therefore customer 1 would face a higher final charge than customer 2.
310. Under the site-specific scaling approach, the two customers would face different allocations of costs (reflecting differences in the length of circuits serving them) as well as different FCP/LRIC charges. The combined effect of these charge elements could mean that customer 1 may well have lower final charges than customer 2.

- 311. Preservation of charging signals from the FCP/LRIC methodology is therefore seen as an advantage of the voltage level scaling approach.
- 312. Following discussions held with Ofgem, customers, suppliers and LDNOs, the DNOs have concluded that cost-reflectivity takes priority over the preservation of signals from marginal charges.
- 313. The additional granularity offered by the site-specific approach is considered by DNOs to result in better cost-reflectivity, and would therefore better meet the overall objectives of the EDCM.

Annex 5: Rationale for the allocation split

- 314. Under the proposed methodology for demand scaling, 20 per cent of the difference between the EDCM demand revenue target and the sum of charges relating to direct operating costs, indirect costs and network rates (the residual revenue) is to be allocated using a £/kVA fixed adder. The other 80 per cent of the residual revenue will be allocated on the basis of notional shared assets.
- 315. This annex explains the rationale behind the choice of 80 per cent and 20 per cent.
- 316. The DNOs believe that asset values are a fair and cost reflective basis for allocating the bulk of the DNOs' allowed revenue. However, there are elements of the DNOs allowed revenue that do not seem suited to this method of allocation.
- 317. In particular, the elements relating to the DNOs' tax allowances, pension deficit repair costs and expensed pension costs are considered better allocated as a fixed adder, rather than on the basis of site-specific assets.
- 318. To work out the proportion of the DNOs' allowed revenue that relates to these elements, we rely on Ofgem's most recent price control determinations (DPCR5).
- 319. Table 7 contains an extract from Ofgem's final proposals relating to DPCR5. The numbers reported show the breakdown of the DNOs' allowed revenue for the five years from 2010/11 to 2014/15.

Table 7 DPCR5 Final proposals – Allowed revenue and cost elements (All DNOs)

	All DNO total DPCR5 (£ million) in 2007/08 prices
Fast pot	3,835.6
Depreciation	7,763.2
Pension deficit repair	1,049.0
Pension cost expensed	173.4
Return	4,017.2
Tax allowance	1,899.7
Capex incentive scheme	26.5
Losses incentive scheme	34.3
DPCR4 costs	115.5
Innovation fund incentive	85.9
Low carbon networks fund	396.0
Transmission exit charges	887.5
IQI incentive allowance	252.8
Pass through costs (includes network rates)	1,655.1
Excluded revenues	52.7
Allowed price control revenue (before profiling)	22,122.7

Ofgem – Electricity Distribution Price Control Review Final Proposals – Allowed revenue financial issues, 7 December 2009.

320. The amounts titled fast pot, transmission exit charges and pass through costs in the table above relate to DNO expenditure that may be recovered in the year they are incurred through charges to customers. Taken together, these account for £6,378.2 million over the price control period.
321. These elements fit in with the cost elements that have been pre-allocated under the EDCM (direct operating costs and indirect costs, transmission exit charges and network rates respectively).

322. The price control elements that are related to the part of the allowed revenue that has not been pre-allocated under the EDCM (the residual revenue) is £15,744.5 million (£22,122.7 million minus £6,378.2 million).
323. The elements titled tax allowance, pension deficit repair and pension cost expensed make up £3,122.1 million over the price control period. This represents 19.82 per cent of the remaining £15,744.5 million. The corresponding figures for individual DNO areas range from 13.1 per cent to 26.1 per cent.
324. The DNOs believe that a GB-wide figure of 20 per cent would be a reasonable estimate of the average proportion of residual revenue that corresponds to tax allowances, pension deficit repair and pension cost expensed, and therefore the proportion of residual revenue that should be allocated using a fixed £/kVA adder across all DNO areas.

Annex 6: Demand scaling methodology

325. Demand scaling using the site-specific assets approach involves the following steps:
- a) Calculating adjusted site-specific shared asset values for each customer using network use factors that have been subjected to a cap and collar.
 - b) Allocation of the direct operating cost and network rates elements in the EDCM demand revenue target to individual EDCM demand users on the basis of adjusted site-specific assets and sole use assets.
 - c) Allocation of the indirect cost element in the EDCM demand revenue target to individual EDCM demand customers in the basis of their consumption at the time of DNO peak and 50 per cent of maximum import capacity as a p/kVA/day charge.
 - d) Estimating the notional recoveries from the application of LRIC or FCP charges to EDCM demand users.
 - e) Allocation of 80 per cent of the difference between the EDCM demand revenue target and the sum of charges under (a), (b) and (c) above on the basis of adjusted site-specific assets.
 - f) Allocation of 20 per cent of the difference between the EDCM demand revenue target and the sum of charges under (a), (b) and (c) above on the basis of consumption at the time of peak and 50 per cent of maximum import capacity as a p/kVA/day fixed adder.
326. Adjusted site-specific assets are calculated using network use factor that have been subjected to caps and collars.
327. A cap and a collar would be calculated for each network level as follows:
- a) In ascending order, list the network use factors for all demand users in all DNO areas relating to that network level, excluding all the factors that are either equal to zero or 1, or not used, based on the customer categories of each demand user.
 - b) Divide the list into two segments, one that contains factors that are lower than 1, and the other than contains the factors that are higher than 1.
 - c) Take the list segment containing factors that are lower than 1. Starting from the lowest factor in this list segment, calculate the factor at the 15th percentile. This is the collar.
 - d) Take the list segment containing factors higher than 1. Starting from the lowest factor in this segment, calculate the factor at the 85th percentile. This is the cap.
328. The same cap and collar would apply in all DNO areas to NUFs at that network level.
329. The caps and collars for each network level calculated using this methodology are set out in table 8 below. Illustrative tariffs for 2011/2012 have been calculated using these values.

Table 8 Network use factor caps and collars

Network levels	Collar	Cap
132 kV	0.273	2.246
132kV/EHV	0.677	1.558
EHV	0.332	3.290
EHV/HV	0.631	2.380
132kV/HV	0.697	2.768

330. The caps and collars in the table above would be fixed for three years, and would be used to calculate tariffs for the charging years 2012/2013 and 2013/2014. The caps and collars would be re-calculated for the subsequent three charging years using the averages of the network use factors for each tariff for the previous three years.
331. Table 9 below sets out the schedule for the calculation of caps and collars for each charging year.

Table 9 NUF cap and collar calculation timeline

Charging Year	NUFs used create the cap and collar
2011/2012 Submission	2011/2012 NUFs
2012/2013	2011/2012 NUFs
2013/2014	2011/2012 NUFs
2014/2015	Average of 2011/2012, 2012/2013, 2013/2014 NUFs
2015/2016	Average of 2011/2012, 2012/2013, 2013/2014 NUFs
2016/2017	Average of 2011/2012, 2012/2013, 2013/2014 NUFs
2017/2018	Average of 2014/2015, 2015/2016, 2016/2017 NUFs
2018/2019	Average of 2014/2015, 2015/2016, 2016/2017 NUFs
2019/2020	Average of 2014/2015, 2015/2016, 2016/2017 NUFs
2020/2021	Average of 2017/2018, 2018/2019, 2019/2020 NUFs
2021/2022	Average of 2017/2018, 2018/2019, 2019/2020 NUFs
2022/2023	Average of 2017/2018, 2018/2019, 2019/2020 NUFs

332. Separate adjusted site-specific asset values per kVA (in £/kVA) is calculated in respect of each network level. The asset value for the network level of connection is based on the maximum capacity of the user, and for network levels above on consumption at peak time.

Adjusted site-specific asset value for capacity at level L (£/kVA) = NUa_L * Average network asset value for capacity at level L (£/kVA)

Adjusted site-specific asset value for demand at level L (£/kVA) = NUa_L * Average network asset value for demand at level L (£/kVA)

Where:

NUa_L is the adjusted network use factor for that user at level L after application of the cap and collar.

Average notional asset value for capacity at level L is the voltage level average calculated as described earlier.

Average notional asset value for demand at level L is the voltage level average calculated as described earlier.

333. The total value of the adjusted site-specific shared assets required to serve each demand user is calculated according to the formula:

$$TNAa = NACa + NADa$$

Where:

TNAa is the total adjusted site-specific network assets in £/kVA required to serve a demand user.

NACa is the adjusted site-specific asset value in £/kVA for capacity for that demand user aggregated across all levels.

NADa is the adjusted site-specific asset value in £/kVA for demand for that demand user aggregated across all levels.

334. Total adjusted site-specific shared assets for all EDCM demand is the aggregate value (in £) of all adjusted site-specific shared assets for EDCM demand users. This is calculated by multiplying NACa and NADa by the import capacities and historical consumption at peak for each customer, and then aggregating across all EDCM demand.
335. The direct cost and network rates allocations to individual demand customers will be determined in the same way as the contributions to the EDCM demand revenue target was calculated, except that adjusted site-specific assets would be used.
336. A single asset based charging rate for network rates is calculated for all EDCM users. This is calculated as follows:

Network rates charging rate (per cent) = $NR / (\text{Total adjusted site specific assets} + \text{Total EDCM sole use assets} + \text{EHV assets} + \text{HV and LV network assets} + \text{HV and LV service model assets})$

Where:

NR is the total DNO expenditure on network rates.

Total adjusted site-specific assets is the aggregate value (in £) of all adjusted site-specific assets for EDCM demand users.

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM users (demand and generation).

EHV assets is the aggregate EHV assets in the CDCM model.

HV and LV network assets from the CDCM model.

HV and LV service model assets from the CDCM model.

337. A single asset based charging rate for direct operating costs is calculated for all EDCM users. This is calculated as follows:

Direct operating costs charge rate (per cent) = $\text{DOC} / (\text{Total adjusted site-specific assets} + \text{Total EDCM sole use assets} + \text{EHV assets} + (\text{HV and LV network assets} + \text{HV and LV service model assets}) / 0.68)$

Where:

DOC is the total DNO expenditure on direct operating costs.

Total adjusted site-specific assets is the aggregate value (in £) of all adjusted site-specific assets for EDCM demand users.

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM users (demand and generation).

EHV assets is the aggregate EHV assets in the CDCM model.

HV and LV network assets from the CDCM model.

HV and LV service model assets from the CDCM model.

0.68 is the operating intensity factor.

338. The charging rates for network rates and direct operating costs are converted into p/kVA/day import capacity based charges for each EDCM demand user.

Network rates and direct costs charge in p/kVA/day = $(100 / \text{DC}) * \text{TNAa} * (\text{NR rate} + \text{DOC rate})$

Where:

DC is the number of days in the charging year.

TNAa is the total adjusted site-specific assets (£/kVA) for that demand user.

NR rate is the network rates charge rate in per cent.

DOC rate is the direct operating costs charge rate in per cent.

339. The charging rates for network rates and direct operating costs are converted into a p/day fixed charge for the sole use assets of each EDCM demand user as follows:

Fixed charge on sole use assets in p/day = $100 / DC * S * (NR \text{ rate} + DOC \text{ rate})$

Where

DC is the number of days in the charging year.

S is the MEAV of sole use assets of that user.

NR rate is the network rates charge rate in per cent.

DOC rate is the direct operating costs charge rate in per cent.

340. The same formula is used to calculate the fixed charges on sole use assets for generation tariffs.

341. A p/kVA/day charging rate for indirect costs for each EDCM demand customer is calculated on the basis of historical demand at the time of DNO peak and 50 per cent of maximum import capacity of that customer.

Indirect cost charging rate in p/kVA/day = $100 / DC * (\text{Aggregate indirect cost contribution}) / \text{Volume for scaling}$

Where:

DC is the number of days in the charging year.

Aggregate indirect cost contribution is the sum of the indirect cost contribution from each EDCM demand user.

Volume for scaling is the sum of historical consumption at the time of peak and 50 per cent of maximum import capacity of all EDCM demand users.

342. The p/kVA/day charging rate for indirect costs is converted into a import capacity based charge for each demand user as follows:

Import capacity based INDOC charge in p/kVA/day = $\text{Indirect cost charging rate} * (0.5 + \text{coincidence factor})$

Where:

Indirect cost charging rate is the DNO-wide p/kVA/day rate calculated as described in the previous paragraph.

0.5 is the proportion of the maximum import capacity of that demand user which is taken into account for the purposes of charging.

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by maximum capacity in kVA of that customer (based on historical data).

343. A single asset based residual revenue charging rate is calculated for all EDCM demand users. This is calculated as follows:

Residual revenue charging rate (per cent) = $0.8 * (\text{EDCM demand revenue target} - \text{DOC recovery} - \text{INDOC recovery} - \text{NR recovery} - \text{SU recovery} - \text{FCP/LRIC recovery}) / \text{Total site-specific assets}$

Where:

0.8 is the proportion of the residual revenue that is allocated to customers on the basis of asset values.

DOC recovery is the forecast notional recovery from the application of capacity based charges relating to direct operating costs to EDCM demand customers.

INDOC recovery is the forecast notional recovery from the application of capacity based charges relating to indirect costs to EDCM demand customers.

NR recovery is the forecast notional recovery from the application of capacity based charges relating to network rates to EDCM demand customers.

SU recovery is the forecast notional recovery from the application of fixed charges for sole use assets relating to EDCM demand customers.

Total site-specific assets is the aggregate value (in £) of all notional shared assets for EDCM demand users.

344. The asset based charging rate for residual revenue is converted into a p/kVA/day import capacity based residual revenue charge for each EDCM demand user.

Asset based residual revenue charges in p/kVA/day = $(100 / \text{DC}) * \text{TNAa} * \text{Residual revenue rate}$

Where:

DC is the number of days in the charging year.

TNA is the total site-specific assets (£/kVA) for that demand user.

Residual revenue rate is the residual revenue charging rate in per cent.

345. A fixed adder in p/kVA/day for the remaining 20 per cent of residual revenue is calculated as follows:

Single fixed adder in p/kVA/day = $100 / \text{DC} * 0.2 * (\text{EDCM demand revenue target} - \text{DOC recovery} - \text{INDOC recovery} - \text{NR recovery} - \text{SU recovery} - \text{FCP/LRIC recovery}) / \text{Volume for scaling}$

Where:

DC is the number of days in the charging year.

EDCM demand target is the EDCM demand revenue target calculated as described in the previous section.

DOC recovery is the forecast notional recovery from the application of capacity based charges relating to direct operating costs to EDCM demand customers.

INDOC recovery is the forecast notional recovery from the application of capacity based charges relating to indirect costs to EDCM demand customers.

NR recovery is the forecast notional recovery from the application of capacity based charges relating to network rates to EDCM demand customers.

SU recovery is the forecast notional recovery from the application of fixed charges for sole use assets relating to EDCM demand customers.

LRIC/FCP recovery is the forecast notional recovery from the application of FCP or LRIC charges to all EDCM demand users only.

Volume for scaling is the sum of forecast consumption at the time of peak and 50 per cent of maximum import capacity of all EDCM demand users (based on historical data).

346. The fixed adder in p/kVA/day is converted into a import capacity based charge for each demand user as follows:

Import capacity based fixed adder in p/kVA/day = Fixed adder * (0.5 + coincidence factor)

Where:

Fixed adder is the DNO-wide p/kVA/day fixed adder calculated as described in the previous paragraph.

0.5 is the proportion of the maximum import capacity of that demand user which is taken into account for the purposes of demand scaling.

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by maximum capacity in kVA of that customer (based on historical data).

Stylised example of demand scaling

347. Let us consider a hypothetical DNO with an EHV network that contains two network levels, 132 kV and 33 kV. Table 10 sets out the characteristics of the network.

Table 10 Stylised example of demand scaling – EDCM demand revenue target

Item	Value
DNO EDCM demand revenue target	£100,000
Direct operating costs element	£10,000
Indirect costs element	£30,000
Network rates element	£20,000
Residual revenue element (a – b – c – d)	£40,000
LRIC/FCP charge recovery (see table 8)	£11,000
Total amount to be recovered through scaling	£29,000
(split 80 per cent on the basis of assets and 20 per cent on the basis of capacity and demand)	(£23,200 and £5,800)
Total Network assets (MEAV)	£15,000,000
Total HV/LV assets (MEAV)	£9,000,000
Total assets at 132 kV (MEAV)	£1,000,000
Total assets at 33 kV (MEAV)	£5,000,000
Notional asset rate at 132 KV (£/kW)	£50 per kW
Notional asset rate at 33 KV (£/kW)	£100 per kW

348. Table 11 sets out the characteristics of the EDCM demand customers.

Table 11 Stylised example of demand scaling options – Customer characteristics

	EDCM demand customer 1	EDCM demand customer 2
Import capacity	1,000 kVA	100 kVA
Demand at the time of DNO peak	500 kW	50 KW
Sum of demand at peak and 50 per cent of capacity (change numbers to be different from row 1)	1000	100
Network level usage	Connected at 132 kV	Connected at 33 kV
LRIC charge	£10/kVA	£10/kVA
Network use factor at 132 kV	0.5	2
Network use factor at 33 KV	0	0.5
Average voltage level assets at 132 kV level	£50,000 (£50/kW multiplied by 1,000 kVA)	£2,500 (£50/kW multiplied by 50 kW)
Average voltage level assets at 33 kV level	Zero (level not used)	£10,000 (£100/KW multiplied by 100 kVA)
Total average voltage level assets	£50,000	£12,500
Site-specific assets at 132 kV level	£25,000 (£50,000 multiplied by 0.5)	£5,000 (£2,500 multiplied by 2)
Site-specific assets at 33 kV level	Zero (level not used)	£5,000 (£10,000 multiplied by 0.5)
Total site-specific assets	£25,000	£10,000

349. Table 12 sets out the calculation of charges.

Table 12 Stylised example – Charges under the site-specific scaling approach

	EDCM demand customer 1	EDCM demand customer 2
Import capacity	1,000 kVA	100 kVA
Demand at the time of DNO peak	500 kW	50 KW
LRIC charge recovery	£10,000 (£10/kVA multiplied by 1,000 kVA)	£1,000 (£10/kVA multiplied by 100 kVA)
Direct operating cost allocation (allocated on the basis of total site-specific assets)	£7,143	£2,857
Network rates allocation (allocated on the basis of total site-specific assets)	£14,286	£5,714
Indirect cost allocation (based on 50 per cent of capacity and demand based)	£27,272	£2,728
80 per cent of scaling allocation (on the basis of total site-specific assets)	£16,571	£6,629
20 per cent of scaling allocation (on the basis of capacity and demand)	£5,272	£528
Total charges	£80,544	£19,456

350. In the site-specific scaling approach, the allocation of direct operating costs, network rates and 80 per cent of scaling is done on the basis of assets adjusted by the network use factors.

351. Customer 1 has a network use factor of 0.5 for the 132 kV network level. This means that the customer is deemed to use half of the average asset value (in £/kW). Similarly, Customer 2 has a network use factor of 2 for the 132 kV network level, this means that the customer is deemed to use double the average asset value (in £/kW).

Annex 7: Generation scaling

352. The first step in generation scaling is to create a generation scaling target. This target contains the sum of:

- a) The actual DG incentive revenue from post-2005 generation (CDCM and EDCM) in £/year (see explanation further down this section).
- b) The notional DG incentive revenue from pre-2005 generation (CDCM and EDCM) in £/year.

353. In calculating generation tariffs for the charging year, the actual DG incentive revenue from post-2005 DG is to be calculated as follows:

$$[\text{Actual DG incentive revenue from post-2005 DG } \text{£/year}] = \text{GI} + \text{GP} + \text{GO} + \text{GL}$$

Where:

GI is the total incentive payment in the charging year, calculated as in paragraph 11.4 of the Special Conditions of the Electricity Distribution Licence (CRC11).¹⁵

GP is the pass-through revenue in the charging year in respect of the relevant Capex calculated as in paragraph 11.6 of the Special Conditions of the Electricity Distribution Licence (CRC11).

GO is the O&M allowance in the charging year in respect of the relevant Capex calculated as in paragraph 11.8 of the Special Conditions of the Electricity Distribution Licence (CRC11).

GL is the incentive revenue in the charging year in respect of DG connected between 2005 and 2010 calculated as in paragraph 11.10 of the Special Conditions of the Electricity Distribution Licence (CRC11).

354. For the purposes of calculating the notional DG incentive revenue from pre-2005 generation, we will use the O&M charging rate multiplied by [1 – a sole use factor]. This charging rate was set to £1/kW/year in 2007/2008 and then indexed to RPI in following years.

355. The sole use factor is calculated by dividing the total MEAV of sole use assets relating to DG by the sum of 132kV, 132kV/EHV, EHV (33kV circuits), EHV/HV and 132kV/HV asset MEAVs. In the case of mixed import and export sites, sole use assets that are attributed to the import MPAN should also be added to the MEAV of DG sole use assets.

356. The notional DG incentive revenue from pre-2005 generation is calculated by multiplying the relevant capacity by the adjusted O&M charging rate.

357. The next step in the calculation is to allocate the DG incentive revenue target between EDCM and CDCM generation. This allocation is done on the basis of export capacities of generation. This gives an EDCM generation revenue target.

¹⁵ Special Conditions of the Electricity Distribution Licence, 31 March 2010 – Available from <http://www.ofgem.gov.uk/Networks/ElecDist/PriceCtrls/DPCR5/Documents1/CRCs%20master%20merged.pdf>

358. The calculation of the EDCM generation target can be summarised by the following formula:

$$[\text{EDCM G-target } \text{£/year}] = [\text{Actual DG incentive revenue from post-2005 DG } \text{£/year} + \text{Notional incentive revenue for pre-2005 DG } \text{£/year}] / [\text{Total capacity of CDCM and EDCM DG kVA}] * [\text{EDCM generation capacity kVA}]$$

359. The next step is to calculate the forecast revenue from the application of the FCP or LRIC charge 2 £/kVA/year to EDCM generation. Revenues from fixed charges (associated with sole use assets) are not taken into account.
360. The fixed adder is then calculated as the £/kVA/year number, that when applied to EDCM generation capacity, would make up the shortfall (or excess) between the EDCM generation target and the forecast revenue from the application of FCP or LRIC charges.
361. If the adder is negative, it is only applied to each generation tariff to the extent that keeps the FCP/LRIC export capacity charge non-negative.

Stylised example of generation scaling

362. A stylised example is presented here to illustrate the mechanics of generation scaling.
363. Let us consider a hypothetical DNO with an installed total export capacity of 100 MVA in the charging year. Table 13 provides the breakdown by site.

Table 13 Generators in the hypothetical DNO

	Date of connection	Sole use asset MEAV	Export capacity
Generator A (EDCM)	Pre-2005	£1 million	60 MVA
Generator B (EDCM)	Post-2005	£10,000	30 MVA
EDCM total			90 MVA
Generator C (CDCM)	Pre-2005	£10,000	5 MVA
Generator D (CDCM)	Post-2005	£10,000	5 MVA
CDCM total			10 MVA
DNO total			100 MVA

364. We now calculate the generation scaling target for this hypothetical DNO.
365. The first step is to add together the following:
- The actual DG incentive revenue from post-2005 generation (CDCM and EDCM) in £/year.

- b) The notional DG incentive revenue from pre-2005 generation (CDCM and EDCM) in £/year.
366. The method for calculating the actual DG incentive revenue for post-2005 generation is described in the previous section. We will not go into the details here. For the purposes of this illustrative example let us assume that this is equal to £20,000.
367. The notional DG incentive revenue from pre-2005 is calculated by multiplying the export capacities of all post-2005 generation by the O&M charging rate, adjusted for sole use assets.
368. Let us assume that the O&M charging rate for the DNO in the charging year is £1.00/kW.
369. The O&M charging rate relates to all DNO network assets, including sole use assets. In this example, let us assume that 1 per cent of assets at EHV are sole use assets. Therefore the adjusted O&M rate for shared assets is 99 per cent of £1.00, which is £0.99/kW.
370. The total export capacity of pre-2005 generators (both EDCM and CDCM) is 65 MVA.
371. The notional DG incentive revenue relating to pre-2005 generation is therefore equal to £0.99/kW multiplied by 65,000, which is £64,350. We assume a power factor of 1 in this example.
372. Therefore the total DG incentive revenue for all generation is £84,350.
373. The EDCM generation revenue target is calculated by splitting this incentive revenue into EDCM and CDCM components. This is done on the basis of export capacities.
374. EDCM generators account for 90 per cent of the DNO's total installed export capacity. Therefore the EDCM generation revenue target is 90 per cent of £84,350, which is £75,915.
375. We now calculate the forecast recoveries from the application of FCP/LRIC charges to the EDCM generators. Let us assume that both generators face a LRIC charge of £2/kVA/year. The DNO's forecast notional recovery from the application of this charge would be £180,000 (2 x 90,000 kVA). We assume there are no excess reactive power charges.
376. The forecast notional recovery is higher than the revenue target of £84,350 by £104,085 (£180,000 minus £75,915).
377. This excess recovery is converted into a £/kVA adder (negative, since it is an excess) by dividing the excess by the total EDCM capacity. This gives a negative adder of £1.156/kVA/year.
378. We also assume that the sole use asset charging rate for direct costs, indirect costs and network rates are equal to 1 per cent of sole use asset MEAV.
379. Table 14 sets out the final charges for the EDCM generators in our hypothetical DNO.

Table 14 Final charges for EDCM generators in the hypothetical DNO

	Generator A	Generator B
Sole use asset MEAV	£1 million	£10,000
Sole use asset charging rate	1 per cent	1 per cent
Sole use asset charge	£10,000	£100
Export capacity	60 MVA	30 MVA
LRIC charge	£2/kVA/year	£2/kVA/year
LRIC charge recovery	£120,000	£60,000
Generation scaling fixed adder	£1.156/kVA/year (negative)	£1.156/kVA/year (negative)
Scaling charge	£69,360 (negative)	£34,680 (negative)
Final EDCM charge	£60,640	£25,420

Annex 8: Tariffs for LDNOs

380. This annex describes the part of the methodology for EHV designated LDNO distribution systems in relation to their end users who fall within the scope of the CDCM.
381. For users that fall within the scope of the CDCM, the extended method M would be used to calculate discount percentages that would apply to the CDCM all-the-way tariffs.
382. Separate discount percentages would be calculated for end users connected at LV circuits, HV/LV substations and at HV circuits. For each type of end user, different discount percentages would apply depending on the category of the boundary between the host DNO and the LDNO.
383. Under the EDCM, the DNO's network is divided into five network levels:
- a) Level 1 comprises 132 kV circuits
 - b) Level 2 comprises substations with a primary voltage of 132 kV and a secondary voltage of 22 kV or more.
 - c) Level 3 comprises circuits of 22 kV or more, excluding circuits already categorised as being in Level 1.
 - d) Level 4 comprises substations with a primary voltage of 22 kV or more but less than 132 kV and a secondary voltage of less than 22 kV.
 - e) Level 5 comprises substations with a primary voltage of 132 kV and a secondary voltage of less than 22 kV.
384. DNOs may designate 66 kV circuits belonging to either network level 1 or 3 and substations with a primary voltage of 66 kV into level 2 or level 4 or level 5, depending on their network planning policies.
385. We would determine the network level of the boundary between the host DNO and the LDNO distribution system by reference to the asset ownership boundary between the host DNO and the LDNO.
386. Where the LDNO distribution system only has one end user (whether a designated EHV property or not), the network level of the boundary between the host DNO and LDNO would be determined by reference to the distribution point of common coupling (DPCC). The DPCC would be determined in the same way as it would be for an EDCM demand customer connected directly to the host DNO's network.
387. For EDCM demand customers, the distribution point of common coupling is the point on the network where the power flow associated with the single customer under consideration, may under some (or all) possible arrangements interact with the power flows associated with other customers, taking into account all possible credible running arrangements.
388. LDNO distribution system would be split into 15 categories based on the network level of the boundary between the host DNO and the LDNO, and whether or not higher network levels are used by the LDNO.

Table 15 Categorisation of designated EHV LDNOs

Category	Definition
Category 0000	Boundary at the GSP, whether the GSP is shared or not, with no use of any circuits.
Category 1000	In England or Wales only, boundary at a voltage of 132 kV, unless the customer qualifies for category 0000.
Category 1100	Boundary at 22 kV or more on the secondary side of a substation where the primary side is attached to a 132 kV circuit.
Category 0100	Boundary at 22 kV or more, but less than 132 kV, on the secondary side of a substation where the primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.
Category 1110	Boundary at a voltage of 22 kV or more, but less than 132 kV, not at a substation, fed from a substation whose primary side is attached to a 132 kV distribution circuit.
Category 0110	Boundary at a voltage of 22 kV or more, but less than 132 kV, not at a substation, fed from a substation whose primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.
Category 0010	Boundary at a voltage of 22 kV or more, but less than 132 kV, fed from a GSP with no intermediate transformation and no use of any 132 kV circuits.
Category 0001	Boundary at a voltage of less than 22 kV on the secondary side of a substation where the primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.
Category 0002	Boundary at a voltage of less than 22 kV on the secondary side of a substation where the primary side is attached at 22 kV or more but less than 132 kV, to a co-located GSP with no use of any 132 kV circuits.
Category 1001	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is attached to a 132 kV distribution circuit.
Category 0011	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed from a GSP with no intermediate transformation and no use of any 132 kV circuits.

Category 0111	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed through a distribution circuit from a substation whose primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.
Category 0101	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed from the secondary side of a co-located substation whose primary side is attached at 132 kV to a co-located GSP with no use of any circuit.
Category 1101	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more but less than 132 kV, with no use of 33 kV circuit, fed from the secondary side of a co-located substation whose primary side is attached to a 132 kV distribution circuit.
Category 1111	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed through a distribution circuit from a substation whose primary side is attached to a 132 kV distribution circuit.

389. All references to GSP in the table above relate to interconnections with the main interconnected onshore transmission network.

The extended “Method M” model

390. The extended price control disaggregation model (the extended method M model) calculates discount percentages in a two-part process.
391. For the purposes of the first part of the process, the DNO’s network is split into four levels: LV, HV/LV, HV and EHV.
392. The first part of the price control disaggregation involves the calculation of separate percentages by network level of each element of the DNO’s price control allowed revenue: the operating cost, depreciation and return on RAV elements. These are aggregated over the period 2005/2006 to 2009/2010 (the DPCR4 period).
393. In order to determine the allocation to network levels of each element of price control revenue, the following cost allocation drivers are used:
- a) Data submitted by the DNOs to Ofgem using the format prescribed in the regulatory reporting pack (RRP) on units distributed and operating expenditure broken down by network level (typically relating to the year 2007/2008).

- b) Data that each DNO considers appropriately represents the forecast of net capital expenditure and customer contributions for the period 2005/06–2014/15, broken down by network level.
 - c) Forecast data that each DNO considers appropriately represents the gross modern equivalent asset values (replacement costs) for various asset types.
394. Data from the RRP are used to distinguish between direct and indirect costs, with direct costs coded by network level. For the purpose of this calculation, capital expenditure are included, net of customer contributions, but negative figures are replaced with zero. This analysis provides direct costs percentage for each network level.
 395. Indirect operating costs are allocated to network levels on the basis of an estimate of MEAV by network level.
 396. The operating cost percentage for each level is a weighted average of the direct and indirect percentages. Estimated gross modern equivalent asset values used for this purpose are derived from asset counts and unit costs DNO forecasts wherever available. Transmission exit charges are excluded from the allocation because it does not seem reasonable to allocate these charges to different network levels.
 397. Both the depreciation and return on capital elements of allowed revenue are allocated to network levels on the basis of net capital expenditure data derived from DNO estimates and forecasts. All figures are aggregated over the 10-year period from 2005/2006 to 2014/2015, taking in actual data or forecasts for each year as available.
 398. For each network level, the relevant net capital expenditure is calculated by adding up total condition based replacement (proactive and reactive) replacement, combined in the case of LV, HV and EHV with connections spend minus customer contributions for connections at that voltage level, general reinforcement capital expenditure at that voltage level, and fault reinforcement capital expenditure at that voltage level.
 399. Some of these categories allow HV substation and transformer costs to be identified. These costs (and no other costs) are allocated to the HV/LV network level. Some of the expenditure categories do not separately identify HV substation/transformer costs. For these categories costs are allocated to the HV/LV in the same proportion as for the other categories (where these costs are separately identified).
 400. Generation-related capital expenditure is not included in the net capex attributable to each network level.
 401. The allocation to each network level of each element of the DNO's price control allowed revenue is then aggregated by network level to create network level totals. These totals are then converted into network level percentages.
 402. The network level percentages are used to allocate the DNO's allowed revenue less the net amount earned or lost by the licensee under price control financial incentive schemes less the total DNO transmission exit charges. All three numbers relate to a single year (typically 2007/2008).

403. The allowed revenue allocations are then rescaled by the estimated number of units flowing through each network level, and normalised so that they sum to 100 per cent. The net amount earned or lost by the licensee under price control financial incentive schemes plus the total DNO transmission exit charges (the unallocated part of the allowed revenue) is rescaled by the number of units flowing through the EHV network level. The result of this calculation is a set of percentages for each of the LV, HV/LV, HV and EHV network levels, and one percentage for the unallocated DNO revenue.
404. The second part of the price control disaggregation process is to split the percentage for the EHV network level in the above calculation into separate percentages for the following EDCM asset levels:
- a) 132 kV circuits (England and Wales only);
 - b) 132kV/33kV substations (England and Wales only);
 - c) 33 kV circuits; and
 - d) 33kV/HV substations
405. The extended Method M model does not calculate separate percentages for 132kV/HV substations. This is because input data on the costs of 132kV/HV substations are not reported in the RRP.
406. In the absence of separate percentages for 132kV/HV substations, the DNOs propose to use the percentage for the 132kV/EHV substation as a proxy. This represents a change from the proposal set out in the February 2011 mini-consultation (which proposed to use the percentage for the EHV/HV substation). The DNOs believe that this is a pragmatic assumption given the lack of relevant data across all DNO areas. Feedback on the original proposal received from LDNOs has also contributed to this decision.
407. For each combination of an end user network level and a boundary network level, the relevant discount for demand end users is calculated as follows:

Discount percentage = [the sum of the percentages for network levels not provided or bypassed by the DNO] / ([the sum of the percentages for all network levels that would be provided by the DNO for an equivalent end user on its network] + [Percentage of unallocated DNO revenue])

Where:

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

Network levels not provided or bypassed by the DNO are all network levels below the network level of boundary up to and including the network level of the end user.

Percentage of unallocated DNO revenue 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.

408. Whereas demand tariffs reflect costs at the network level of supply and at every level above that, generation tariffs only reflect costs above the network level of supply. For example, credits to HV generators do not include anything based on the costs of HV networks.

409. For example, consider an LDNO with a boundary with the host DNO at 132 kV circuits (category 1000), with LV demand end users. The discount applicable would be calculated as follows:

$$\text{Discount percentage} = [132\text{kV/EHV} + \text{EHV} + \text{EHV/HV} + \text{HV} + \text{HV/LV} + \text{LV}] / ([132\text{kV} + 132\text{kV/EHV} + \text{EHV} + \text{EHV/HV} + \text{HV} + \text{HV/LV} + \text{LV}] + [\text{Percentage of unallocated DNO revenue}])$$

Where:

The network levels in the formula represent the discounts applicable at that level.

Percentage of unallocated DNO revenue is calculated as described earlier in this section.

410. If the same category 1000 LDNO had an HV generation end user, the discount would be calculated as follows:

$$\text{Discount percentage} = [132\text{kV/EHV} + \text{EHV} + \text{EHV/HV}] / ([132\text{kV} + 132\text{kV/EHV} + \text{EHV} + \text{EHV/HV}] + [\text{Percentage of unallocated DNO revenue}])$$

411. A boundary category 0011 LDNO (for example, the boundary at a 66kV/11kV substation which is connected using 66 kV circuits to a 275kV/66kV GSP) with an HV demand end user would have a discount calculated as follows:

$$\text{Discount percentage} = [\text{HV}] / ([\text{EHV} + \text{EHV/HV} + \text{HV}] + [\text{Percentage of unallocated DNO revenue}])$$

412. In each case, the discount would be applied to all CDCM tariff components.

413. In the method outlined in the paragraphs above, if sum of the DNO's total incentive revenue and the transmission exit charge is a negative number, the formula could return a discount percentage which is greater than 100 per cent.

414. In other words, if the DNO's total incentive revenue is a large negative number, and larger in absolute terms than the DNO's transmission exit charges, the calculated discount percentage could be greater than 100 per cent.

415. Discount percentages that are greater than 100 per cent would result in a credit to the LDNO in respect of demand use of system charges and a payment from the LDNO to the DNO in respect of generator use of system credits. To avoid this eventuality, discount percentages are capped to 100 per cent.

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416. Under the CDCM, discount percentages for two tariff combinations where the boundary and the end users are on the same network level (HV boundary with HV end-users, and LV boundary with LV end-users) include an element attributable to

that network level (HV or LV circuits respectively. Other LDNO tariff combinations do not attract these elements.

417. Under the extended Method M, there are no tariff combinations where the boundary and the end user are on the same network level.
418. Therefore, we propose to calculate discounts on the assumption that an LDNO that is connected to the host DNO at 132 kV circuits or 33 kV circuits would not be eligible for discount elements in respect of these circuits.
419. In other words:
- a) an LDNO with a boundary with the host DNO at 132 kV circuits is assumed to use as much of the 132 kV network as the average transformation down from 132 kV; and
 - b) an LDNO with a boundary with the host DNO at 33 kV circuits is assumed to use as much of the 33 kV network as the average transformation down from 33 kV.
420. The illustrative discounts published alongside this submission are consistent with this assumption.
421. The DNOs are working on a DCUSA change proposal under the CDCM (DCP071) that would potentially extend these elements to all LDNO tariff combinations. We do not expect this proposal to be approved before 1 April 2011, i.e. the date of submission of this document to Ofgem.
422. Once the proposals under DCP071 are finalised and approved, the DNOs would work with LDNOs to review the method proposed above for LDNOs with a boundary at 132 kV or 33 kV and, if necessary, develop an appropriate methodology to calculate additional discount elements.
423. These additional discount elements might apply to the following tariff combinations:
- a) 132 kV boundary: HV, HV/LV and LV end users
 - b) 33 kV boundary: HV, HV/LV and LV end users
424. For each combination of end user network level and boundary network level, the relevant discount for demand end users would then be calculated as follows:

Discount percentage = $\left(\left(\text{the sum of the percentages for network levels not provided or bypassed by the DNO} \right) + \left(\left[\text{percentage for 33kV or 132 kV} \right] * \left[\text{network length split} \right] * \left[\text{direct cost proportion} \right] \right) \right) / \left(\left(\text{the sum of the percentages for all network levels that would be provided by the DNO for an equivalent end user on its network} \right) + \left[\text{Percentage of unallocated DNO revenue} \right] \right)$

Where:

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

The sum of the percentages for network levels not provided or bypassed by the DNO are all network levels below the network level of boundary up to and including the network level of the end user. This does not include the 132 kV or 33 kV network levels where the boundary is at 132 kV or 33 kV respectively.

Percentage for 33 kV or 132 kV is the discount percentage applicable to the 33 kV or 132 kV network level. For a 33 kV boundary LDNO, we would use the discount percentage for the 33 kV network level.

Network length split is the ratio of the length of circuits on relevant network level (33 kV or 132 kV) that is deemed to be provided by the LDNO to that provided by the host DNO.

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.

425. Percentage of unallocated DNO revenue 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.

Portfolio EDCM tariffs for end users in the EDCM

426. For end users on a LDNO's distribution system that would be covered by the EDCM if they were on the DNO's network, the proposal is to apply the EDCM methodology to calculate a portfolio EDCM charge/credit for each such end user.
427. These EDCM portfolio tariffs would be calculated as if each EDCM end user on the LDNO's distribution system were notionally connected at the boundary between the DNO and LDNO.
428. Such end users would attract charges (credits) in respect of any reinforcements caused (avoided) on the DNO's network only, i.e. any network branches that are on the LDNO's network would be attributed a zero FCP/LRIC charge/credit.
429. The setting of final charges to embedded Designated EHV Properties including the calculation of charges for assets used on the embedded network will be established by the LDNO.
430. All EDCM charges would be calculated using "boundary equivalent" data provided by the LDNO to the host DNO for each embedded Designated EHV Property. For the purposes of the EDCM, boundary equivalent data should be what the LDNO has allowed for at the DNO-LDNO boundary, for each EDCM end user, after taking into consideration the diversity and losses within the LDNO's network. Data relating to CDCM end users must be considered for the purposes of calculating boundary equivalent data in order to cater for the effect of diversity and losses.
431. The DNOs propose to include in the tariffs for embedded Designated EHV Properties a fixed charge relating to any assets on the DNO's network that are for the sole use of an embedded LDNO network. These fixed charges would be calculated in the same way as it would be for EDCM customers connected directly to the host DNO's network.

432. In calculating charges for assets on the DNO's network that are for the sole use of an embedded LDNO distribution system, DNOs will charge only for the proportion of sole use assets deemed to be used by embedded Designated EHV Properties. This proportion will be calculated, in respect of each embedded Designated EHV Properties, as the ratio of the boundary equivalent capacity of that end user to the capacity at the LDNO/DNO boundary.
433. If there are no embedded Designated EHV Properties on the LDNO's network, no sole use asset charges would apply.
434. Demand scaling would be applied as normal to any EDCM portfolio tariff in respect of a demand user. For the purposes of scaling, all EDCM demand end users connected to the LDNO's network will be treated as notional EDCM demand end users connected to the DNO's network at the voltage level of the boundary.
435. For EDCM demand end users connected to the LDNO's network, the capacity-based charge for the DNO's indirect costs would be scaled down by a factor of 50 per cent.
436. This scaling is necessary because the EDCM allocates indirect costs by customer size (and not by asset values). As a result, the indirect cost allocation needs to be scaled down to allow the LDNO to recover an appropriate margin on the end user tariff in relation to its own indirect costs. Given that each interconnection between a DNO and LDNO could have involve a different split of network assets, obtaining accurate data to inform the calculation of this scaling factor would be disproportionately difficult. In light of this, the DNOs have adopted a pragmatic assumption of 50 per cent for the indirect cost split.
437. Generation scaling will be applied as normal to generators connected to the LDNO's network. Again, boundary equivalent export capacities would be used to calculate the generation scaling revenue target.
438. The following table lists the different types of data that the LDNO would be required to provide in respect of end users connected to their network. This must be provided for each of the following:
- a) An export tariff for each EDCM-like demand or generation end user site that can export (including any nested or offshore networks).
 - b) An import tariff for each EDCM-like demand or generation end user site that can import (including any nested or offshore networks).

Table 16 Boundary equivalent data items that the LDNO must provide

Item	Description
LLFC	This is the line loss factor class for the tariff (or any other short identifier). This is for labelling purposes and does not affect any calculations.
Tariff name	This is a full name/identifier for the tariff.
Demand or Generation	Whether the tariff is a demand or generation tariff.

Historical peak-time kW divided by historical agreed kVA (demand only)	This should be calculated using historical consumption and agreed import capacity for that customer. Historical refers to the last regulatory year for which data are available. If [super-red]AI denotes active power import for each half hour during the super-red time band in kWh, and average kVA is the average of the agreed import capacity over the last regulatory year for which data are available, then the formula for this item is: $\text{Sum}[\text{super-red}](\text{AI})/[\text{super-red hours}]/[\text{average kVA}]$ Details of the super-red time band have been published an appendix to the EDCM December 2010 consultation. If the customer is new or its circumstances have changed since the last regulatory year for which data are available, an estimate of the current value should be provided.
Historical peak-time kVAr divided by historical agreed kVA (demand only)	This item only needs to be provided to DNO's that use the FCP methodology to calculate marginal charges. This column contains a number for each demand customer that should be calculated using historical net reactive power import (reactive import minus reactive export) and agreed import capacity for that customer. Historical refers to the last regulatory year for which data are available. If [super-red](RI – RE) denotes net reactive power import for each half hour during the super-red time band in kVAr, and average kVA is the average of the agreed import capacity over the last regulatory year for which data are available, then the formula for this item is: $\text{Sum}[\text{super-red}](\text{RI} - \text{RE})/[\text{super red hours}]/[\text{average kVA}]$ Details of the super-red time band have been published an appendix to the EDCM December 2010 consultation. If the customer is new or its circumstances have changed since the last regulatory year for which data are available, an estimate of the current value should be entered.
Network support factor (generation only)	The network support factor is 1 in the case of sites with non-intermittent generation (e.g. thermal plants). It is 0 in the case of sites with intermittent generation (e.g. wind power).
Forecast average agreed capacity (kVA)	Data relate to either import or export capacity, as appropriate for each tariff. The figure is the forecast average over the charging year.
Forecast average exceeded capacity (kVA)	Data in this column relate to either import or export capacity, as appropriate for each tariff. The figure is the forecast average excess over the charging year. Excess capacity is to be measured on the basis of maximum use in each billing month.

Forecast active
power units (kWh)
(for generation only)

This is the forecast active power generation over the
charging year.

Proportion of the site
which is pre-2005
(generation only)

This is the proportion of average agreed capacity that was
connected to the LDNO's network before April 2005.

439. The method for calculating the generation revenue target within the EDCM requires an estimate of total installed CDCM generation capacity on the DNO's network. LDNOs must therefore provide the DNO an estimate of the aggregate embedded CDCM generation capacity on their network, split between pre-2005 capacity and post-2005 capacity.