SCHEDULE 18 – EHV CHARGING METHODOLOGY (LRIC MODEL)

**This Schedule 18, version 10.0, is to be used for the calculation of Use of System Charges which will become effective from, 01 April 2018 and remain effective until superseded by a revised version.**

# INTRODUCTION

## This Schedule 18 sets out one, of the two, EHV Distribution Charging Methodologies (EDCM). The other EDCM is set out in Schedule 17.

## This Schedule 18 sets out the methods, principles, and assumptions underpinning the EDCM for the calculation of Use of System Charges by the following DNO Parties:

Eastern Power Networks plc;

Electricity North West Limited;

London Power Networks plc;

Northern Powergrid (Northeast) Limited;

Northern Powergrid (Yorkshire) plc;

South Eastern Power Networks plc;

Western Power Distribution (South Wales) plc; and

## Western Power Distribution (South West) plc.

## In order to comply with this methodology statement when setting distribution Use of System Charges the DNO Parties referred to above will populate the EDCM model version L204 when issued by the Panel in accordance with Clause 14.5.3.

Main steps

## The EDCM involves four main steps.

## Step 1 is the application of load flow techniques and the LRIC or FCP methodologies to determine an EDCM tariff element, known as Charge 1, which represents costs associated with demand-led reinforcement, estimated by reference to power flows in the maximum demand scenario.

## Step 2 involves the allocation of DNO Party costs to Connectees using appropriate cost drivers.

## Step 3 adds a scaling element to charges which is related to Allowed Revenue.

## Step 4 uses CDCM charges to determine the element of portfolio charges to be applied in the case of DNO/IDNO Parties who are supplied from the DNO Party’s network at voltages higher than the scope of CDCM charges.

## Figure 1 provides a diagrammatic overview of the steps involved for import charges.

Figure 1 Diagrammatic overview of the EDCM for import

## EDCM NoGen

# LONG RUN INCREMENTAL COST PRICING ANALYSIS

Introduction

## This Schedule 18 sets out the principles and high-level detail that should be adopted as the common approach to EDCM Use of System Charging that is based on the Long Run Incremental Cost (LRIC) model.

## The LRIC model calculates Nodal incremental costs. These costs represent the brought forward (or deferred) reinforcement costs caused by the addition of an increment of demand or generation at each network Node. The method models the impact changes in Connectees’ behaviour have on network costs.

## In particular, the LRIC model takes account of the effects a change in Connectee behaviour has on the network by using AC power flow analysis, which enables the calculation of the time needed before elements of the network require reinforcement and subsequently the net present value (NPV) of the future costs of reinforcement. The incremental cost is equal to the difference in the NPV of reinforcing under existing conditions and when an increment of new demand or generation is added.

## To calculate Use of System Charges for EDCM Connectees (demand and generation), the common LRIC method consists of the following stages:

##### LRIC model:

###### AC power flow analysis;

###### calculation of Branch incremental costs (in £/annum); and

###### calculation of Nodal incremental costs (including the consideration of the Maximum Demand Scenario and the Minimum Demand Scenario; in £/annum);

###### calculation of Nodal, Charge 1 (by taking account of the magnitude of the increment driving the incremental costs; in £/kVA/annum).

##### derivation of site-specific Use of System Charges (including the consideration of sole use asset charges, transmission exit charges and operating and maintenance costs); and

##### scaling to derive the final EHV Use of System Charges.

Power Flow Analysis

## Power flow analysis calculates the effects of adding an increment of demand or generation to the DNO Party’s Distribution System. In particular, it calculates the power flows passing over the various assets comprising the DNO Party’s network under base and incremented conditions using maximum (typically during the winter period) and minimum (typically during the summer period) demand data.

## The power flow analysis calculates the following values for each Node/Branch combination:

##### base power flows using Maximum Demand Data and Minimum Demand Data, and

##### incremented power flows using Maximum Demand Data and Minimum Demand Data.

## Power flow analysis uses a number of processes and assumptions as follows:

##### A representation of the entire EHV network captured using appropriate power flow modelling software (the Authorised Network Model)[[1]](#footnote-1). The modelled network should be based on the network expected to exist and be in operation in the Regulatory Year that Use of System Charges are being calculated for, based on the DNO Party’s Long Term Development Statement (save that, until 5 November 2016, where charges are being calculated for two or more Regulatory Years, the same Authorised Network Model will be used for all the years).

##### AC power flows should be calculated for maximum and minimum demand base conditions and for maximum and minimum demand conditions plus an increment of demand or generation[[2]](#footnote-2). A 0.1MW Nodal increment should be used in relation to calculating the active demand and generation elements of the incremented power flows, assuming that the power factor is 0.95 for increments applied at Nodes where demand is located and unity for increments applied at Nodes where generation is located. Increments will be applied in the direction of demand for the analysis of maximum demand network conditions and in the direction of generation for the analysis of minimum demand conditions. Where both demand (load) and generation are located at a Node, separate incremental power flows shall be calculated using increments at 0.95 power factor and at unity power factor.

##### Nodal demand and generation data should be used, which is based on actual metered network usage data that is recovered from the DNO Party’s Supervisory Control and Data Acquisition (SCADA) (or equivalent) system. In particular:

###### **Demand Data** – for the maximum demand period, the model uses demands consistent with those used to assess reinforcement[[3]](#footnote-3). This includes diversity to allow a complete EHV network model to be run[[4]](#footnote-4). Minimum demands are taken as being a percentage of maximum demands[[5]](#footnote-5). This percentage is derived for each Grid Supply Point (GSP) and applied to the demands supplied by that GSP;

###### **Generation Data** - for the maximum demand period generation is zero unless it is deemed to contribute to network security in accordance with ER P2/6[[6]](#footnote-6). The generation export used for the minimum demand period is the Maximum Export Capacity for each EDCM (Generation) Connectee, factored to reflect coincidence with other generation export. This factor is derived for each GSP and applied to EDCM (Generation) Connectees connected to that GSP. These are broadly similar to the assumptions that are used by the DNO Party when investment planning[[7]](#footnote-7);

###### **Cleansing Data** - the DNO Party should cleanse demand and generation data so that it is representative of typical network usage. That is, anomalous power flows, which represent, for example, demand levels at a time when the network is experiencing an outage, should be removed from the data set and the effects of load management schemes should be taken account of[[8]](#footnote-8);

###### **Growth Rate** - a single underlying network growth rate is used to assess the timing of future reinforcement for both demand and generation Connectees. It represents the long run growth of all DNO Parties’ networks and is set to 1% growth per annum. To facilitate predictability and stability, the growth rate is used throughout the model, and (as with all assumptions) the DNO Party should keep this growth rate under review. As a minimum, the rate should be reviewed and reset when the charge restriction conditions in the DNO Party’s Distribution Licence are reviewed every five years; and

###### **Security Factors** - a pair of Security Factors should be determined[[9]](#footnote-9) for each Branch using a full N-1 Contingency Analysis assuming maximum and minimum demand conditions[[10]](#footnote-10). These factors are used to determine the usable capacity of network Branches during maximum and minimum demand conditions. They are recalculated each time the network is changed or new load estimates used. Each N-1 Contingency will consider the consequential network actions and where appropriate constraints on Connectee demands (both generation and load) to meet the security of supply requirements of E/R P2/6.

##### The results of the power flow analysis are sense checked to identify where application of Security Factors to the incremented power flows leads to excessively large (and non-credible) estimations of the change in Branch utilisation. The following conditions are identified:

###### low base power flows;

###### high Security Factors; and

###### where the difference between the base and incremented Branch power flows exceeds the change that could reasonably be expected to occur as a result of the application of an increment of demand or generation.

##### Where such cases are encountered a modified approach to the anticipated change in power flow in the Branch is used. Guidance on the sense checking of the power flow analysis results is provided in section 8.3of Annex 1. This approach does not apply the Security Factor when considering the change in flow between the incremented and the base case power flow.

Calculation of Branch incremental costs

## The incremental cost of reinforcing a Branch due to an increment at a Node is the difference in the net present value (NPV) of reinforcing the Branch under base and incremented conditions. An explanation of the derivation of the formulae used to calculate Branch incremental costs is provided in Annex 2.

## The Branch incremental cost, denoted, is calculated using the following formulae:

## 

## 

**Branch Capacity** is the MVA rating of the “critical” asset in the considered Branch divided by the corresponding Security Factor; a pair of Branch capacities is calculated for maximum demand and minimum demand conditions. Guidance on Branch ratings is provided in section 7.5 of Annex 1. Guidance on sense checking Security Factors prior to the calculation of Branch incremental costs is provided in section 8.3 of Annex 1.

is the modern equivalent asset value (MEAV) of reinforcing the particular Branch, bearing in mind the requirements of similar historic projects. This cost is the same under both base and incremented conditions. The DNO Party should use the specifications and costs of similar, past reinforcement projects as a means for determining the requirements and costs of a particular future reinforcement project. Guidance on the reinforcement cost calculation principles is provided in section 7.4 of Annex 1.

***YearsToReinforcement*** is the number of years into the future when reinforcement of the Branch will be required. This is calculated separately under base and incremented conditions.

 is set to equal the latest pre-tax real weighted average cost of capital (CC below) for each DNO Party calculated using the following formula:

CC = (Gearing Assumption x Pre-Tax Cost of Debt) + (1- Gearing Assumption)\*(Post Tax Cost of Equity/(1-Corporation Tax Rate))

where:

Gearing Assumption is set to the ‘notional Gearing’ value referred to in the ED1 Price Control Financial Handbook;

Pre-Tax Cost of Debt is set to the ‘cost of corporate debt’ value specified in or calculated in accordance with the most recent Annual Iteration Process applicable when setting distribution Use of System Charges;

Post Tax Cost of Equity is set to the ‘cost of equity’ value referred to in the ED1 Price Control Financial Handbook; and

Corporation Tax Rate is the rate of corporation tax which is, when setting distribution Use of System Charges, expected to be applicable in respect of the Regulatory Year in which those Charges will take effect.

The CC value is calculated as a percentage, and rounded to two decimal places.

***GrowthRate*** is the growth rate in per units of the power flow, currently set at 1%.

 is the period over which costs are annuitised. This period is set to 40 years and represents the typical life of an asset.

## Separate assessment of the total Branch cost recovery associated with incremental costs that represent charges, PositiveCostRecovery, and the total Branch recovery associated with incremental costs that represent credits, NegativeCostRecovery, is done to eliminate over-recovery of both the charges and credits.

## Two total Branch cost recoveries, namely PositiveCostRecovery and NegativeCostRecovery, are derived from the power-flow modelling and sense checked for each Branch individually. Guidance on sense checking of overall positive and negative Branch cost recoveries is provided in section 8.3 of Annex 1.

## The positive Branch cost recovery for a particular Branch is calculated by adding together the cost recovery for the Branch at each Node where the incremental cost is positive (i.e. ‘charge’, determined by the product of the positive Branch incremental costs and the appropriate Nodal demands, or generation output, used in the modelled network).

## Similarly, the negative Branch cost recovery is calculated for the Branch where each Node incremental cost is negative (i.e.‘credits’, determined by the product of the negative Branch incremental costs and the appropriate Nodal demands, or generation output, used in the modelled network).

## Both sense checks only consider Branch incremental costs associated with the period that drives reinforcement. Where either the positive or the negative (by absolute value) cost recovery for a particular Branch is greater than the actual reinforcement cost of the Branch (ActualReinforcementCost, as determined by the product of the Annuity Rate and the CostofReinforcementSolution), then it is considered that the Branch recovery of charges or credits is excessive.

## In order to limit the level of positive Branch cost recovery (charges) to being no greater than the actual reinforcement cost of the Branch, a Positive Cost Recovery Factor, , is applied to the positive Branch incremental costs associated with Branch i, when used in the calculation of Nodal incremental costs. Similarly, a Negative Cost Recovery Factor, sNi, is applied to the negative Branch incremental costs associated with Branch i in order to limit the level of negative Branch cost recovery (credits).

## Where the positive cost recovery associated with Branch i (ie charges) is determined by the sense checking, to be excessive then:-

sPi = ActualReinforcementCosti / PositiveCostRecoveryi

otherwise:-

sPi = 1

Where the negative cost recovery associated with Branch i (i.e. credits) is determined to be excessive, then:-

sNi = *ActualReinforcementCosti/NegativeCostRecoveryi*

sNi = 1.

## The EHV network includes single Connectees using sole-use assets that have been sized to their connection requirements. Costs for these assets should be excluded from the calculation of incremental costs. Replacement and operation and maintenance costs for these assets should also be excluded from the calculation of incremental costs, but may be incorporated into a Connectee’s final Use of System Charge.

Calculation of Nodal incremental costs

## Guidance on the calculation of Nodal incremental costs, is provided in section 8 (Output results) of Annex 1. The formulae used to calculate Nodal incremental costs are described in Annex 2.

## A pair of incremental costs (one for the Maximum Demand Scenario and another for the Minimum Demand Scenario) is calculated for each Node by summating Branch incremental costs that result from applying an increment at that Node. A peak Nodal incremental cost is calculated by summating Branch peak incremental costs, where maximum demand conditions drive Branch reinforcement. An off-peak Nodal incremental cost is calculated by summating Branch off-peak incremental costs, where minimum demand conditions drive Branch reinforcement. Only Branches that experience a change greater than both 1kVA and 0.01 % of Base Power Flow in the power that flows across them are used in the calculation of Nodal charges. The period that is deemed to drive reinforcement is the period with the highest absolute incremental cost.

## The formulaic expression for Nodal incremental cost is given by:



## and denote the incremental cost of reinforcing Branch *i*, under maximum and minimum demand conditions respectively, due to an increment of demand or generation at the Node;

## denotes the Recovery Factor for Branch *i*;

## *B* is the total number of Branches in the network;

## α and β are subsets of Branches where relevant conditions are satisfied.

Calculation of Nodal marginal charges for demand

## Guidance on the calculation of Nodal marginal charges for demand sites is provided in section 8.12 (Demand Nodes) of Annex 1.

## The Nodal incremental costs for demand sites are derived using Branch incremental costs produced by application of 0.1MW increments at 0.95 power factor, which is equivalent to 0.10526MVA. The Nodal marginal charges for demand in (£/kVA/annum) are obtained by dividing the Nodal incremental cost for each period by the absolute value of the kVA increment:

ChargeAtNodePeak = IncrementalCostAtNodePeak / 105.26 (£/kVA/annum)

## A positive value of ChargeAtNodePeak represents a charge for demand sites at the Node, whereas a negative value represents a credit. This statement defines the sign convention of the Nodal marginal charges (as outlined in section 8 (Output results) of Annex 1 and Attachment 3 (Output results) to Annex 1. However, it should be noted that this does not describe the application of these charges in the calculation of final Use of System Charges (or credits in respect of final Use of System Charges).

**Generation sites**

## Guidance on the calculation of Nodal marginal charges for generation sites is provided in section 8.13 (Generation Nodes) of Annex 1.

## The Nodal incremental costs for generation sites are derived using Branch incremental costs produced by application of 0.1MW increments at unity power factor being equal to 0.1MVA. The Nodal marginal charges for generation are obtained by dividing the Nodal incremental cost for each period by the absolute value of the kVA increment:

ChargeAtNodePeak = IncrementalCostAtNodePeak / 100 (£/kVA/annum)

## A positive value of ChargeAtNodePeak represents a credit for generation sites at the Node, whereas a negative value represents a charge. This statement defines the sign convention of the Nodal marginal charges (as outlined in section 8 (Output results) of Annex 1 and Attachment 3 (Output results) to Annex 1. However, it should be noted that this does not describe the application of these charges in the calculation of final Use of System Charges (or credits in respect of final Use of System Charges).

Decomposition of Nodal marginal charges

## Each Nodal marginal charge, derived from the Nodal incremental costs, is decomposed into two sub-elements, termed ‘local’ and ‘remote’, such that:-

ChargeAtNodePeak = LocalChargeAtNodePeak + RemoteChargeAtNodePeak

## The local element of each charge at a Node is derived from:-

##### the Branch incremental costs associated with Branches that are operating at the same nominal voltage as the voltage of the Node where the increment was applied; and

##### the Branch incremental costs associated with Branches that represent transformation from a higher voltage down to the same nominal voltage as the voltage of the Node where the increment was applied.

## The remote element of each Nodal incremental cost is derived from the Branch incremental costs from all Branches other than those where the Branches are operating at the same nominal voltage as the voltage of the Node where the increment was applied, or where the Branches represent transformation from a higher voltage down to the same nominal voltage as the Node. In other words, all Branches that are not ‘local’ are ‘remote’.

Outputs from LRIC Analysis

## The LRIC methodology produces the following outputs:

##### Location (Node);

##### Demand Type (Generation or Load);

##### Local Charge 1: LocalChargeAtNodepeak (£/kVA/annum);

##### Remote Charge 1: RemoteChargeAtNodepeak (£/kVA/annum);

##### Active Power (kW) for the Maximum Demand Scenario;

##### Reactive Power (kVAr) for the Maximum Demand Scenario;

# EDCM charge components for Connectees

## This section sets out the different charge components that will apply to Connectees under the EDCM. Charge components are the outputs of the EDCM and make up the distribution use of system charges applied to Connectees.

## In the EDCM, each set of charges comprises import rates, export rates, or both, as applicable to the Connectee. The DNO Party’s Relevant Charging Statement includes information that enables a Supplier to determine which Designated EHV Property each set of charges applies to.

## Demand charges under the EDCM comprise the following individual components:

Import fixed charges.

Import capacity charges.

Exceeded import capacity charges.

Unit rate charges for consumption at the time of the DNO Party’s peak (super-red time band).

## The EDCM charge components for import are listed in Table 1.

Table 1 Charge components for import

| **Tariff component** | **Unit** |
| --- | --- |
| Import fixed charge | p/day |
| Import capacity charge | p/kVA/day |
| Exceeded import capacity charge | p/kVA/day |
| Super-red import unit charge | p/kWh |

## Generation charges under the EDCM comprise the following individual components:

Export fixed charges

Export capacity charges

Exceeded export capacity charges

Export super-red unit rate (credit)

## The EDCM charge components for export are listed in Table 2.

Table 2 Charge components for export

| **Charge component** | **Unit** |
| --- | --- |
| Export fixed charge | p/day |
| Export capacity charge | p/kVA/day |
| Exceeded export capacity charge | p/kVA/day |
| Export super-red unit rate | p/kWh |

## The next section details the calculation of the elements that determine the charge components described above.

# Calculation of EDCM charge components

## EDCM charge components are derived from charge elements. This section describes the method for calculating each of these charge elements.

# Chargeable export capacity for export charges

## The Chargeable Export Capacity for each Connectee is defined as the Maximum Export Capacity minus any capacity that is exempt from use of system charges in the charging year.

# Application of LRIC charge 1

## Each tariff in the model is linked to one LRIC location or point. Each LRIC point may have a local and remote charge 1 in £/kVA/year associated with it.

## Some LRIC points might be designated as linked. Each set of linked points comprises a maximum of eight points. Where a tariff is associated with a point which is part of a set of linked points, the LRIC charge 1 used for that tariff are determined by calculating the applicable local and remote charge 1 as a weighted average of the local and network charge 1 respectively at each linked point (ignoring negative values) using the kVA modelled flow in the maximum demand run as weights. If all the weights are zero in any of these calculations then an unweighted average is used instead of the weighted average.

## The import charges for the application of charge 1, is given by the formulas:

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

[p/kVA/day capacity charge] = ([local charge 1 £/kVA/year] /[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. This is calculated as - [Active power flow] / (SQRT([Active power flow]^2 + [Reactive power flow]^2). If either the numerator or denominator in calculation of the power factor is zero, the PF is replaced with 1. If the active power flow is generation-dominated, then PF is replaced with 1.

## If the Connectee is attached to a cluster of linked locations, the sums of active power flows and reactive power flows at each location are used to calculate PF.

## Charge 1 is applied to export charges as a credit. The credit is expressed as a negative charge rate in p/kWh and is applied in respect of active power units exported during the DNO Party’s super-red time band. The credit rate is set to zero for Connectees who are assigned an F Factor of zero. The credit rate is calculated as follows:

[p/kWh super-red export rate] = -100\*[Proportion eligible for charge 1 credits]\*([local charge 1 £/kVA/year] + [remote charge 1 £/kVA/year]) \* ([Chargeable export capacity]/[Maximum export capacity]) /[number of hours in the super-red time band]

Where:

The proportion eligible for charge 1 credits is zero if the F factor that is assigned to the Connectee as described in the LRIC methodology is equal to zero, and 1 otherwise.

The super-red export rate is not applied to Connectees with zero Chargeable Export Capacity.

# No application of negative charges

## Under LRIC, charge 1 can be negative at some locations. Any negative values of Charge 1 (both local and remote) are set to zero.

# Demand side management (DSM) and Generation side management (GSM)

## Some EDCM Customers are subject to demand side management (DSM) or generation side management (GSM) agreements.

## For Connectees with DSM agreements, let “chargeable capacity” be equal to the Maximum Import Capacity minus the capacity that is subject to restrictions under a DSM agreement. These restrictions would take into account any seasonal variations built into these agreements.

## For Connectees with DSM agreements, DSM-adjusted local and remote (or parent and grandparent) elements of the LRIC charge are calculated as the product of the ratio of “chargeable capacity” to Maximum Import Capacity and the unadjusted elements of the LRIC charge. Where the Maximum Import Capacity is zero, this ratio is set to 1. The DSM-adjusted local element of the LRIC charge 1 is applied to the Maximum Import Capacity, and the DSM-adjusted remote (or parent and grandparent) element of the LRIC charge 1 is applied to units consumed during the super-red time band.

## For Connectees with GSM agreements, no adjustments are made in the EDCM.

# Transmission connection (exit) charges for demand

## A separate transmission exit charge is applied to demand tariffs.

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

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

Where:

DC is the number of days in the Charging Year.

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

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

Total EDCM peak time consumption (in kW) calculated by multiplying the Maximum Import Capacity of each Connectee by the forecast peak-time kW divided by forecast maximum kVA of that Connectee (adjusted for losses to transmission and, if necessary, for Connectees connected for part of the Charging Year) and aggregating across all EDCM Customer demand.

## The single p/kW/day charging rate is converted into a p/kVA/day import capacity based charge for each EDCM Connectees as follows:

Transmission exit charge p/kVA/day = [Transmission exit charging rate in p/kW/day ] \* [Forecast peak-time kW divided by kVA of that Connectee, adjusted for transmission losses and, if necessary for Connectees connected part of the year]

# Transmission connection (exit) credits for generators

## A capacity-based credit related to transmission exit is applied to generation tariffs.

## Transmission exit credits are 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.

## The rate in p/kVA/day for each generation customer would be calculated as follows:

Transmission exit credit p/kVA/day = -[Transmission exit charging rate in p/kW/day] \* [Capacity eligible for credits in kW] / [Chargeable Export Capacity in kVA of that Connectee]

Where:

Transmission exit charging rate in p/kW/day is calculated as described for demand tariffs.

Capacity eligible for credits (in kW) is the capacity that is made available by the generator under the agreement with the DNO.

Chargeable Export Capacity (in kVA) is the forecast average value of the maximum export capacity of the generator over the charging year, less any capacity that is exempt from use of system charges in the charging year.

## The generation transmission connection (exit) rate is not calculated for Connectees with zero Chargeable Export Capacity.

## Transmission connection (exit) credits are applied to the Chargeable Export Capacity (in kVA)

# Reactive power charges

## The EDCM does not include a separate charge component for any reactive power flows.

# Export capacity charges

## The EDCM includes an export capacity charge.

## First, an EDCM generation revenue target would be calculated as follows:

## EDCM DG revenue target £/year = GL \* [Total 2005-2010 EDCM generation capacity] / ([Total 2005–2010 EDCM generation capacity] + [Total 2005–2010 CDCM generation capacity]) + AGPa \* [Total post–2010 EDCM generation capacity] / ([Total post–2010 EDCM generation capacity] + [Total post–2010 CDCM generation capacity]) + (OM \* ([Total Pre–2005 EDCM DG capacity] + [Total Post–2010 EDCM DG capacity]))

Where:

GL is the incentive revenue in the charging year in respect of generation connected between 2005 and 2010 calculated for the charging year as in paragraph 11.10 of the Special Conditions of the Electricity Distribution Licence (CRC11). From and including Regulatory Year 2015/2016 GL is zero.

AGPa is the average of the values of GPa for the charging year and each of the two years immediately preceding the charging year. For Regulatory Year 2014/2015 GPa is calculated using a modified version of the formula in paragraph 11.6 of the Electricity Distribution Licence (CRC11) resulting from DPCR5. To calculate GPa, the term GPX is replaced by the term GPS in the formula in paragraph 11.6. Both GPX and GPS are defined in paragraph 11.7 of the same document. For Regulatory Years 2015/16 onwards GPa is zero.

Total Pre-2005 EDCM DG capacity is the aggregate maximum export capacity of all non-exempt EDCM generators that connected before 1 April 2005, adjusted for part-year connected generators. In the case of generators that have subsequently increased their maximum export capacity, the part of their capacity that was added after 1 April 2005 would be ignored.

Total 2005–2010 EDCM generation capacity is the sum of the maximum export capacities of all non-exempt EDCM generators that connected between 1 April 2005 and 31 March 2010, adjusted for part-year connected generators.

Total Post–2010 EDCM generation capacity is the sum of the maximum export capacities of all non-exempt EDCM generators that connected on or after 1 April 2010, adjusted for part-year connected generators. In the case of generators that originally connected before 1 April 2010 and have increased their maximum export capacity on or after 1 April 2010, the capacity that was added after 1 April 2010 should be included.

Total 2005–2010 CDCM generation capacity is the sum of the maximum export capacities of all non-exempt CDCM generators that connected between 1 April 2005 and 31 March 2010, adjusted for part-year connected generators.

Total Post–2010 CDCM generation capacity is the sum of the maximum export capacities of all non-exempt CDCM generators that connected on or after 1 April 2010, adjusted for part-year connected generators.

## OM is an allowance in £/kW in respect of the operational and maintenance costs for assets that are deemed to have been installed for the purposes of connecting generators to the distribution network. The value of OM is set to £0.20/kW.

## A fixed export capacity charge in p/kVA/day is calculated as follows:

Fixed export capacity charge in p/kVA/day = (100 / DC) \* [EDCM DG revenue target] / [Total EDCM generation capacity]

Where:

EDCM DG revenue target in £/year is calculated as described above

Total EDCM generation capacity (in kVA) is the aggregate Chargeable Export Capacity of all Connectees, adjusted, if necessary for Connectees connected part of the year.

## The fixed export capacity charge in p/kVA/day is applied to the Chargeable Export Capacity of each EDCM Connectee.

# Allocation drivers for other charge elements in the EDCM

## In addition to charges calculated using the FCP and LRIC methodologies and transmission connection (exit) charges, the EDCM includes charge elements relating to:

* the DNO Party’s direct operating costs (this includes inspection and maintenance costs, operating expenditure relating to fault repairs and the cost of tree cutting);
* the DNO Party’s indirect costs. (these are costs that are not directly related to network assets, such as business support costs);
* the DNO Party’s network rates (these are business rates paid by DNO Parties); and
* the DNO Party’s residual revenue.

## The residual revenue is that part of the DNO Party’s Allowed Revenue less any revenue relating to the recovery of Eligible Bad Debt pass-through costs that has not been pre-allocated to demand charges using cost-based charge elements. For the avoidance of doubt, Eligible Bad Debt pass-through costs include DNO Party Bad Debt and Bad Debt which the DNO Party is recovering on behalf of LDNOs.

## EDCM charge elements are determined using allocation drivers. The following allocation drivers are used in the EDCM:

* The value of assets that are for the sole use of a Connectee (sole use assets). This is relevant to import and export charges.
* The value of site-specific shared network assets used by the Connectee. This is relevant to import charges only. The sum of historical consumption at the time of system peak and 50 per cent of Maximum Import Capacity. This is relevant to import charges only.
* Chargeable Export Capacity. This is relevant to export charges only.

## The methods used to determine the value of sole use assets and shared site-specific shared network assets are described below.

# Sole use assets

## The value of a customer’s sole use assets used is expressed in the form of a modern equivalent asset value (MEAV) in £.

## Sole use assets are assets in which only the consumption or output associated with a single Connectee can directly alter the power flow in the asset, taking into consideration all possible credible running arrangements, i.e. all assets between the Connectee's Entry/Exit Point(s) and the Point(s) of Common Coupling with the general network are considered as sole use assets.

## The Point of Common Coupling for a particular single Connectee is the point on the network where the power flow associated with the single Connectee under consideration, may under some (or all) possible arrangements interact with the power flows associated with other Connectees, taking into account all possible credible running arrangements.

## Where a single site has both import and export charges, associated with import and export meter registrations, the sole use assets are allocated between the import and export proportionally to Maximum Import Capacity and Maximum Export Capacity respectively. Where any part of the Maximum Export Capacity associated with an export meter registration is exempt from use of system charges in the charging year, the value of sole use assets allocated to the export tariff is reduced by multiplying it by the ratio of the Chargeable Export Capacity to the Maximum Export Capacity.

## Where an EDCM site was originally connected as a single Connected Installation, and has subsequently split into multiple Connected Installations, these sites continue to be considered as one site for the purposes of determining sole use assets. The sole use asset MEAV is allocated between these Connected Installations in proportion to their Maximum Import Capacities and Maximum Export Capacities.

# Site-specific shared network assets

## A Connectee’s notional site-specific shared network asset value is the value of network assets that are deemed to be used by that Connectee, other than sole use assets as defined earlier.

## The value of notional site-specific shared assets used by each Connectee is expressed in the form of a modern equivalent asset value (MEAV) in £.

## The value of shared network assets used by each demand Connectee is calculated as set out below.

## Five levels are defined for the network’s assets:

* Level 1 comprises 132 kV circuits.
* Level 2 comprises substations with a primary voltage of 132 kV and a secondary voltage of 22 kV or more.
* Level 3 comprises circuits of 22 kV or more but less than 132 kV.
* 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.
* Level 5 comprises substations with a primary voltage of 132 kV and a secondary voltage of less than 22 kV.

## In some cases, it might be appropriate to treat 66 kV equipment as being equivalent to 132 kV equipment and allocate Connectees to categories accordingly.

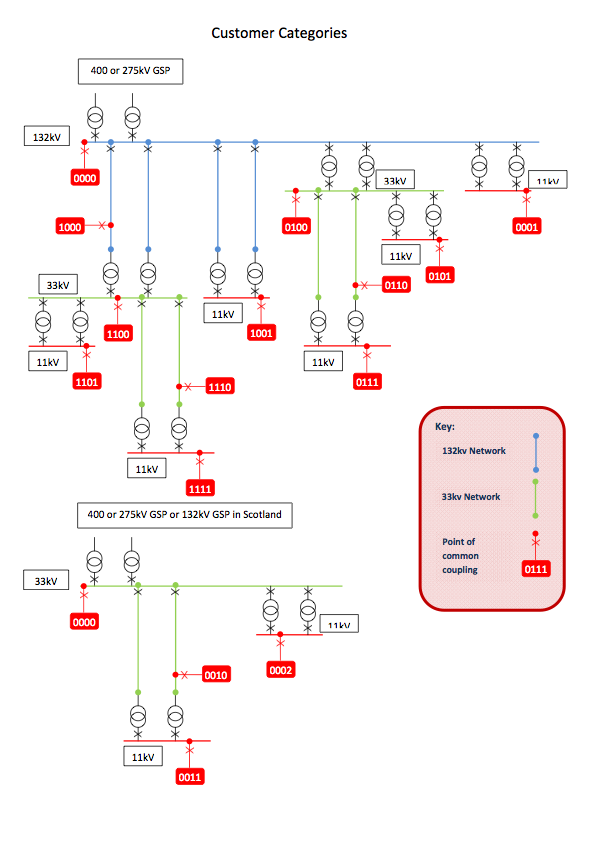
## EDCM Customers are split into 15 categories based on the parts of the EHV network they are deemed to use. This is based on the Point of Common Coupling. The Point of Common Coupling might be at a different voltage than the Connectee’s connection, and might also be at a different voltage than the voltage of connection when the Connectee was connected.

**Table 3 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 Connectee 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. |

## All references to GSP in the table above relate to interconnections with the onshore National Electricity Transmission System.

## The figure below provides examples of Connectees who might be placed in each of the categories described above.



## The use of each network level by each EDCM Connectee is determined 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 |

## Category 0000 Connectees are deemed not to use any network assets other than sole use assets.

## 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 Import Capacity of the Connectee, and for network levels above on consumption at peak time.

Average network asset value for capacity at level L (£/kVA) = NARL\* AE /(1 + DL)

Average network asset value for demand at level L (£/kVA) = NARL\* D \* LAF

Where:

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

DL is the Diversity Allowance from the level exit to the GSP group (from CDCM table 2611).

D is the peak time active power consumption 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 the CDCM for the network level relevant to the EDCM Customer category of that Connectee. See table below for the correspondence between EDCM Customer categories and network levels.

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 (0.95) by the loss adjustment factor to transmission for the network level relevant to that Connectee (as above).

|  |  |
| --- | --- |
| Customer categories | Relevant network level for loss adjustment factors |
| 0000 | GSP (the loss adjustment factor is always 1 for this network level) |
| 1000 | 132kV (level 1) |
| 1100 and 0100 | 132kV/EHV (level 2) |
| 1110, 0110 and 0010 | EHV (level 3) |
| 1111, 1101, 0101, 0111, 0011 and 0002 | EHV/HV (level 4) |
| 1001 and 0001 | 132kV/HV (level 5) |

## Again, separate site-specific asset values per kVA (in £/kVA) are calculated in respect of each network level. The asset value for the network level of connection is based on the Maximum Import Capacity of the Connectee, and for network levels above on consumption at peak time.

Site-specific asset value for capacity at level L (£/kVA) = NUL \* Average network asset value for capacity at level L (£/kVA)

Notional asset value for demand at level L (£/kVA) = NUL \* Average network asset value for demand at level L (£/kVA)

Where:

NUL is the network use factor for that Connectee at level L, representing the proportion of the average 500 MW model assets that the Connectee is deemed to use at that level. The methodology to calculate these network use factors is set out in Annex 2 of this Schedule.

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.

## Network use factors for import charges 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 section 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.

## The total value of the site-specific shared assets required to serve each Connectee is calculated according to the formula:

TNA = NAC + (NAD \* (1 - (Hours in super-red for which not a customer/Annual hours in super-red))\*(Days in year/(Days in year - Days for which not a customer)))

Where:

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

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

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

## Total site-specific shared assets is the aggregate value (in £) of all site-specific shared assets for EDCM Connectees. This is calculated by multiplying TNA by the Maximum Import Capacity (adjusted, if necessary, for Connectees connected for part of the Charging Year), and then aggregating across all EDCM Connectees.

# Calculation of the EDCM demand revenue target

## The EDCM demand revenue target is the share of the DNO Party’s Allowed Revenue less any revenue relating to the recovery of Eligible Bad Debt pass-through costs (excluding transmission exit charges and net revenue from EDCM generation) that will be recovered from EDCM Connectees through import charges.

## This section describes the method used to calculate the EDCM demand revenue target.

## A single contribution rate for network rates is calculated for all EDCM Connectees as follows:

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

Where:

NR is the DNO Party’s total expenditure on network rates.

Total site-specific shared assets is the aggregate value (in £) of all site-specific shared assets for EDCM (Load) Connectees.

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM Connectees, excluding the value of sole use assets associated with exempt export capacity, adjusted for part-year connected Connectees. EHV assets are 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.

## A single contribution rate for direct operating costs is calculated for all EDCM Connectees as follows:

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

Where:

DOC is the DNO Party’s total expenditure on direct operating costs.

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

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM Connectees, excluding the value of sole use assets associated with exempt export capacity, adjusted for part-year connected Connectees. EHV assets are 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.

## A single contribution rate for indirect costs is calculated for all EDCM Connectees as follows:

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

Where:

INDOC is the DNO Party’s total expenditure on indirect costs.

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

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM Connectees, excluding the value of sole use assets associated with exempt export capacity, adjusted for part-year connected Connectee. EHV assets are 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.

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

Residual revenue contribution rate (per cent) = (AR - DOC – INDOC – NR – GCN) / (Total site-specific shared assets + EHV assets + HV and LV network assets)

Where:

AR is the DNO Party’s total Allowed Revenue excluding transmission exit charges in £/year and excluding any revenue relating to the recovery of Eligible Bad Debt pass-through costs.

DOC is the DNO Party’s total expenditure on direct operating costs.

INDOC is the DNO Party’s total expenditure on indirect costs.

NR is the DNO Party’s total expenditure on network rates.

GCN is the total forecast net revenue in £/year from the application of EDCM export charges, including the EDCM generation fixed charge. This amount is estimated by applying the calculated EDCM export charges rounded to the relevant number of decimal points.

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

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

HV and LV network assets from the CDCM model.

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

Import capacity based network rates contribution for each Connectee = TNA \* NR rate \* import capacity

Import capacity based direct operating costs contribution for each Connectee = TNA \* DOC rate \* import capacity

Import capacity based indirect costs contribution for each Connectee = TNA \* INDOC rate \* import capacity

Import capacity based residual revenue contribution for each Connectee = TNA \* residual revenue rate \* import capacity

Where:

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

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 (adjusted, if necessary, if the Connectee is connected for part of the Charging Year) in kVA for that EDCM Connectee.

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

Demand sole use asset based network rates contribution = S \* NR rate

Demand sole use asset based direct operating costs contribution = S \* DOC rate

Demand sole use asset based indirect costs contribution = S \* INDOC rate

Where

S is the MEAV of demand sole use assets of that EDCM Connectee (adjusted for Connectees connected for part of the Charging Year).

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.

## The target contributions from import capacity and sole use assets are aggregated across all EDCM Connectees.

## The aggregate EDCM demand revenue target is calculated as the sum, across all EDCM demand, of the contributions based on import capacities and demand sole use assets, less the total reduction in fixed charges made to EDCM customers under paragraph 17.2. Such fixed charge reduction is to be derived as follows:

FCR = OMR \* (EHV assets + HV and LV network assets) / (Total site-specific shared assets + EHV assets + HV and LV network assets)

Where

OMR is the total reduction in fixed charges made to EDCM customers under paragraph 17.2, where the reduction is derived as the aggregated value of the amount each EDCM customer would have paid under paragraph 17.1 less the amount paid under 17.2 for eligible customers.

# Fixed charges for import and export

## The contribution rates for network rates and direct operating costs are converted into a p/day fixed charge for the sole use assets of each EDCM Connectee as follows:

Import fixed charge on sole use assets in p/day = 100 / DC \* SD \* (NR contribution rate + DOC contribution rate)

Export fixed charge on sole use assets in p/day = 100 / DC \* SG \* (NR contribution rate + DOC contribution rate)

Where

DC is the number of days in the Charging Year.

SD is the MEAV of sole use assets allocated to demand of that EDCM Connectee.

SG is the MEAV of sole use assets allocated to generation of that EDCM Connectee excluding the value of sole use assets associated with exempt export capacity.

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

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

## Where a customer demonstrates with written evidence to the DNO Party (or where the DNO Party has written evidence) that the customer (or its predecessors) made a capitalised O&M payment in respect of a connection to the DNO Party’s network, and the period over which the O&M payment was capitalised remains unexpired, then the import fixed charge will be calculated as set out below (and the calculation for the import fixed charge in paragraph 17.1 will not apply).

The sole use assets will be split between those where capitalised O&M has been paid and those where it has not, and the fixed charge will be derived as follows:

p/day = (((DOC rate + NR rate) \* SUA  MEAVU) + (NR rate \* SUA  MEAVP)) / (days in Charging Year) \* 100

Where:

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

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

Where SUA MEAVU is the Modern Equivalent Asset Value of Sole Use Assets where capitalised O&M has not been paid (or the period over which it was to be capitalised has expired);

and SUA MEAVP is the Modern Equivalent Asset Value of Sole Use Assets where capitalised O&M has been paid (and the period over which it was to be capitalised has not expired).

## For customers that are classified as exempt pre-2005 EDCM Distributed Generators (DGs), it is deemed for the purposes of paragraph 17.2 that the customer paid capitalised O&M to be capitalised over a period of 25 years from connection.

# Demand scaling

## Demand scaling is the process by which import charges to EDCM Connectees are set so that the forecast notional recovery from the application of those import charges to EDCM Connectees matches the EDCM demand revenue target.

## Demand scaling using the site-specific assets approach involves the following steps:

* Calculating adjusted site-specific shared asset values for each Connectee using network use factors that have been subjected to a cap and collar.
* Allocation of the direct operating cost and network rates elements in the EDCM demand revenue target to individual EDCM Connectees on the basis of adjusted site-specific assets and sole use assets. [a]
* Allocation of the indirect cost element in the EDCM demand revenue target to individual EDCM Connectees on the basis of their consumption at the time of the DNO Party’s peak and 50 per cent of Maximum Import Capacity as a p/kVA/day charge. [b]
* Forecasting the notional recoveries from the application of LRIC charges to EDCM Connectee. [c]
* Allocation of 80 per cent of the difference between the EDCM demand revenue target and the sum of a, b and c above on the basis of adjusted site-specific assets.
* 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.

## Adjusted site-specific assets are calculated using network use factor that have been subjected to caps and collars.

## A cap and a collar are calculated for each network level as follows:

* In ascending order, list the network use factors for all EDCM Connectees in all DNO Party 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 EDCM Connectee.
* 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.
* 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.
* 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.

## The same cap and collar would apply in all DNO Party areas to NUFs at that network level.

## The network use factor (NUF) caps and collars for 2011/2012 and each network level were calculated using this methodology and are set out in Table 4 below. The NUF caps and collars using 2015/2016 data for each network level have also been determined, and are set out in Table 4A below.

**Table 4 Network use factor caps and collars (2011/2012)**

|  |  |  |
| --- | --- | --- |
| **Network levels** | **Collar** | **Cap** |
| 132kV | 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 | 2.678 |

**Table 4A Network use factor caps and collars (using 2015/16 data)**

|  |  |  |
| --- | --- | --- |
| **Network levels** | **Collar** | **Cap** |
| 132kV | 0.192 | 1.859 |
| 132kV/EHV | 0.674 | 1.551 |
| EHV | 0.367 | 2.366 |
| EHV/HV | 0.635 | 1.616 |
| 132kV/HV | 0.808 | 1.652 |

## The caps and collars in Table 4 above were fixed for three years, and were used to calculate charges for the Charging Years 2012/2013 and 2013/2014. The caps and collars are to be re-calculated for the subsequent Charging Years. From Charging Year 2017/2018 onwards the caps and collars are to be calculated using the methodology described in paragraph 18.5 based on the NUFs described in paragraph 18.8. The NUFs themselves are calculated in accordance with paragraphs 29 and 30 below.

## Table 5 below sets out the schedule for the calculation of the NUF caps and collars for each Charging Year.

**Table 5 NUF cap and collar calculation timeline**

|  |  |
| --- | --- |
| Charging Year | Caps and collars |
| 2011/2012 Submission | 2011/2012 caps/collars (as per table 4) |
| 2012/2013 | 2011/2012 caps/collars (as per table 4) |
| 2013/2014 | 2011/2012 caps/collars (as per table 4) |
| 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 | 2015/2016 caps/collars (as per table 4A) |
| 2018/2019 | 2015/2016 caps/collars (as per table 4A) |
| 2019/2020 | 2015/2016 caps/collars (as per table 4A) |
| 2020/2021 | Average of 2015/2016, 2016/2017, 2017/2018 NUFs |
| 2021/2022 | Average of 2015/2016, 2016/2017, 2017/2018 NUFs |
| 2022/2023 | Average of 2015/2016, 2016/2017, 2017/2018 NUFs |
| 2023/2024 | Average of 2017/2018, 2018/2019, 2019/2020, NUFs |
| 2024/2025 | Average of 2017/2018, 2018/2019, 2019/2020, NUFs |
| 2025/2026 | Average of 2017/2018, 2018/2019, 2019/2020 NUFs |

## 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 Import Capacity of the EDCM Connectee, and for network levels above on consumption at peak time.

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

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

Where:

NUaL is the adjusted network use factor for that EDCM Connectee 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.

## The total value of the adjusted site-specific shared assets required to serve each EDCM Connectee is calculated according to the formula:

TNAa = NACa + (NADa \* (1 - (Hours in super-red for which not a customer/Annual hours in super-red))\*(Days in year / (Days in year - Days for which not a customer)))

Where:

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

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

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

## Total adjusted site-specific shared assets for all EDCM demand is the aggregate value (in £) of all adjusted site-specific shared assets for EDCM Connectees. This is calculated by multiplying TNAa by the Maximum Import Capacity (adjusted, if necessary, for Connectees connected for part of the Charging Year), and then aggregating across all EDCM demand.

## The direct cost and network rates allocations to individual demand Connectees is determined in the same way as the contributions to the EDCM demand revenue target was calculated, except that adjusted site-specific assets are used.

## A single asset based charging rate for network rates is calculated for all EDCM Connectee. This is calculated as follows:

Network rates charging rate (per cent) = EDCM NR contribution / (Total adjusted site-specific shared assets)

Where:

EDCM NR contribution is the sum of the import capacity based network rates contribution from each EDCM Connectee.

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

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

Direct operating costs charging rate (per cent) = EDCM DOC contribution / (Total adjusted site-specific shared assets)

Where:

EDCM DOC contribution is the sum of the import capacity based direct costs contribution from each EDCM Connectee.

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

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

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

Where:

DC is the number of days in the Charging Year.

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

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

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

## A p/kVA/day charging rate for indirect costs for each EDCM Connectee is calculated on the basis of historical demand at the time of the DNO Party’s peak and 50 per cent of Maximum Import Capacity of that Connectee.

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

Where:

DC is the number of days in the Charging Year.

Volume for scaling is calculated as the sum of (0.5 + coincidence factor)\* import capacity \* LDNO factor across all EDCM Connectees.

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by Maximum Import Capacity in kVA of that Connectee (based on historical data) multiplied by (1 - (Hours in super-red for which not a customer/Annual hours in super-red))\*(Days in year/(Days in year - Days for which not a customer))

Import capacity is the Maximum Import Capacity (adjusted if the Connectee is connected for part of the Charging Year) in kVA for that EDCM Connectee.

LDNO factor takes the value 0.5 if the EDCM Connectee is connected to a LDNO’s network and 1 otherwise.

Aggregate indirect cost contribution is the sum of the import capacity based and sole use asset based indirect cost contribution from each EDCM Connectee.

## The p/kVA/day charging rate for indirect costs is converted into an import capacity based charge for each EDCM Connectee as follows:

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

Where:

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

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by Maximum Import Capacity in kVA of that Connectee (based on historical data) multiplied by (1 - (Hours in super-red for which not a customer/Annual hours in super-red))\*(Days in year/(Days in year - Days for which not a customer))

LDNO factor takes the value 0.5 if the EDCM Connectee is connected to a LDNO’s network and 1 otherwise.

## A single asset based residual revenue charging rate is calculated for all EDCM Connectees. This is calculated as follows:

Residual revenue charging rate (per cent) = 0.8 \* (EDCM demand revenue target – EDCM NR and DOC capacity contribution - Aggregate indirect cost contribution – SU recovery - /LRIC recovery) / Total adjusted site-specific shared assets

Where:

EDCM NR and DOC capacity contribution is the sum of the import capacity based network rates and direct costs contribution from each EDCM Connectee.

Aggregate indirect cost contribution is the sum of the import capacity based and import sole use asset based indirect cost contribution from each EDCM Connectee.

SU recovery is the forecast notional recovery from the application of import fixed charges (before any rounding) for sole use assets relating to EDCM Connectees.

Total adjusted site-specific shared assets is the aggregate value (in £) of all adjusted site-specific shared assets for EDCM (Load) Connectees.

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

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

Where:

DC is the number of days in the Charging Year.

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

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

## 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 / DC \* 0.2 \* (EDCM demand revenue target – EDCM NR and DOC capacity contribution - Aggregate indirect cost contribution - SU recovery - FCP/LRIC recovery) / 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.

EDCM NR and DOC capacity contribution is the sum of the import capacity based direct costs contribution from each EDCM Connectee (from annex 3).

Aggregate indirect cost contribution is the sum of the import capacity based and import sole use asset based indirect cost contribution from each EDCM Connectee

SU recovery is the forecast notional recovery from the application of import fixed charges (before any rounding) for sole use assets relating to EDCM Connectees.

LRIC recovery is the forecast notional recovery from the application of LRIC charges (before any rounding) to all EDCM Connectees only.

Volume for scaling is calculated as the sum of (0.5 + coincidence factor)\* import capacity.

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by maximum capacity in kVA of that Connectee (based on historical data) multiplied by (1 - (Hours in super-red for which not a customer/Annual hours in super-red))\*(Days in year/(Days in year - Days for which not a customer))

Import capacity is the Maximum Import Capacity (adjusted if the Connectee is connected for part of the Charging Year) in kVA for that EDCM Connectee.

## The fixed adder in p/kVA/day is converted into an import capacity based charge for each EDCM Connectee as follows:

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

Where:

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

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by Maximum Import Capacity in kVA of that Connectee (based on historical data) multiplied by (1 - (Hours in super-red for which not a customer/Annual hours in super-red))\*(Days in year/(Days in year - Days for which not a customer)).

# Application of EDCM charges for EDCM Connectees

## The tariff application rules for the EDCM are the same as for the CDCM wherever possible. Each component of each tariff is rounded to the nearest value with no more than three decimal places in the case of unit rates expressed in p/kWh, and with no more than two decimal places in the case of fixed and capacity charges expressed in p/day and p/kVA/day respectively.

## The part of EDCM portfolio tariffs (for LDNO networks and Distribution Licence exempt networks) that is based on CDCM tariffs will be billed like CDCM tariffs.

## Final EDCM demand charges will have:

1. an import fixed charge on sole use assets (in p/day)
2. an import capacity charge in (p/kVA/day)
3. an import super-red unit rate charge (in p/kWh)
4. an exceeded import capacity charge (in p/kVA/day).

## The import fixed charge on sole use assets in p/day is applied to each EDCM Connectee.

## The final EDCM import capacity charge for each EDCM Connectee in p/kVA/day would be calculated as follows:

EDCM import capacity charge (p/kVA/day) = [LRIC p/kVA/day capacity charge] + [Transmission exit charge p/kVA/day] + [Network rates and direct costs charge in p/kVA/day] + [Indirect costs charge in p/kVA/day] + [Asset based residual revenue charges in p/kVA/day] + [Single fixed adder in p/kVA/day]

## The final EDCM super-red unit rate in p/kWh is the LRIC super-red unit rate as calculated as described earlier in this document.

## If the EDCM import capacity charge (p/kVA/day) calculated above is negative and the Connectee’s average kW/kVA (adjusted for part year) is not equal to zero, the final EDCM super-red unit rate is adjusted as follows:

Adjusted LRIC super-red unit rate in p/kWh = [LRIC super-red rate in p/kWh] + ([EDCM import capacity charge (p/kVA/day)] \* ([Days in the Charging Year] – [Days for which not a customer]) / [Average kW/kVA] / ([hours in the super-red time band] - [Hours in super-red for which not a customer]))

## Finally, any remaining negative import super-red unit rates or import capacity charges are set to zero.

## Final EDCM export charges will have:

1. An export fixed charge on sole use assets (in p/day)
2. An export capacity charge (in p/kVA/day), which might include transmission exit credits to qualifying generators.
3. An export super-red unit rate (in p/kWh)
4. An exceeded export capacity charge (in p/kVA/day)

## The export capacity charge (in p/kVA/day) is applied to the Chargeable Export Capacity of EDCM Connectees.

## The export super-red unit rate (in p/kWh) is applied to active power units exported during the DNO Party’s super-red time band.

# Exceeded capacity charges

## Where a Connectee uses additional capacity over and above the Maximum Import Capacity or Maximum Export Capacity without authorisation, the excess is classed as exceeded capacity.

## For the purposes of determining capacity used, the following formula is used for each half hour:

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

Where:

AI = Import consumption in kWh

RI = Reactive import in kVArh

RE = Reactive export in kVArh

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

Where:

AE = Import consumption in kWh

RI = Reactive import in kVArh

RE = Reactive export in kVArh

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

## For the purposes of calculating exceeded capacity for export charges, any reactive flows during half hours when there is no active power export will not be taken into account.

## Any reactive flows associated with a site which operates subject to grid code requirements for generation or sites providing voltage control at the request of the DNO Party would not be taken into account when calculating import or export capacity used.

## For Connectees other than those that have an agreement with the DNO, the terms of which require them, for the purposes of P2/6 compliance, to export power during supergrid transformer (SGT) outage conditions, the exceeded portion of the export capacity is charged at the same rate as the capacity that is within the Maximum Export Capacity. This is charged for the duration of the month in which the breach occurs.

## For Connectees other than those with DSM agreements, the exceeded portion of the import capacity is charged at the same rate as the capacity that is within the Maximum Import Capacity. This is charged for the duration of the month in which the breach occurs.

## Sites subject to DSM arrangements would normally pay the DSM-adjusted capacity charge for capacity usage up to their Maximum Import Capacities.

## If sites with DSM agreements were to exceed their maximum import capacities, the exceeded portion of the capacity will be charged at a different rate. This will be charged for the duration of the month in which the breach occurs. This charge for exceeded capacity (in p/kVA/day) would be determined as follows;

[Exceeded capacity charge in p/kVA/day] = [Import capacity charge p/kVA/day] + (([LRIC capacity charge p/kVA/day] + ([LRIC super-red rate p/kWh] \* [Average kW/kVA adjusted for part year] \* [super-red hours] / ([days in Charging Year] – [Days for which not a customer]))) \* (1 - ([chargeable capacity]/ [Maximum Import Capacity]))

Where:

The LRIC super-red unit rate and LRIC capacity charges in the equation above are the charges before any adjustments for DSM have been made.

# Application of EDCM import charge components

## Table 6 summarises the method of application of import charge components.

**Table 6 Application of EDCM import charge components**

| **Tariff component** | **Unit** | **Application** |
| --- | --- | --- |
| Import 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) |
| Import super-red unit rate | p/kWh | Applied to active power units consumed during the DNO Party’s super-red time band. |

## Table 7 summarises the method of application of export charge components.

Table 7 Application of EDCM export charge components

| **Tariff component** | **Unit** | **Application** |
| --- | --- | --- |
| Export fixed charge | p/day | Applied as a fixed charge. |
| Export capacity charge | p/kVA/day | Applied to the Chargeable Export Capacity. |
| Exceeded export 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) |
| Export super-red unit rate | p/kWh | Applied to active power units exported during the DNO Party’s super-red time band. |

# Charges for new Connectees

## New Connectees could connect at any time between the publication of EDCM charges for the new Charging Year and the end of that Charging Year.

## If the connection of such Connectees had been anticipated before the publication of charges, the DNO Party would have included forecast data relating to the new Connectee in both the power flow model and the EDCM tariff model. The resulting tariff is applied to the new Connectee, on a pro-rata basis if the price is produced during the Charging Year.

## 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, the DNO Party will:

* Seek indicative load profile information from the new Connectee, failing that, make a reasonable estimate;
* Run the power flow model after including the new Connectee to produce a full set of charges 1 and 2, including for the new Connectee;
* Include the new Connectee’s details, including marginal charges from (a) in the EDCM tariff model, to produce a full set of new charges;
* Use the tariff relating to the new Connectee to calculate charges; and
* Charges relating to the current year for existing Connectees would not change as a result.

## If a Connectee were to change their maximum import or export capacity at any time between the publication of EDCM charges 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.

# DNO to DNO charges

## In the case of DNO Party to DNO Party interconnections, the interconnections are categorised into four types:

##### The interconnector between the DNO Parties is normally closed (active), and there is an identifiable benefit from the existence of the interconnection to one DNO Party only. The other DNO Party does not benefit from the interconnection.

##### The interconnector is normally closed (active), and there is either an identifiable benefit to both DNO Parties, or no clear benefit to either DNO Party.

##### The interconnector is normally open, and the interconnection exists only to provide backup under certain conditions to either DNO Party.

##### All other interconnections between DNO Parties.

## In all cases of type (a), the benefitting DNO Party will be treated as being equivalent to an EDCM Connectee connected to the other DNO Party’s network. The DNO Party providing the benefit will calculate and apply EDCM import charges, except charges for sole use assets. as applicable to the other DNO Party. Export charges or credits will not apply.

## In the case of type (b) interconnections, each DNO Party will treat the other as an EDCM Connectee. Normal EDCM import charges, except charges for sole use assets, will apply. Export charges or credits will not apply.

## Type (c) interconnections are typically covered by special arrangements between DNO Parties. Use of system charges are agreed between DNO Parties and applied outside the EDCM model.

## In every other case, each DNO Party applies import charges to the other as a normal EDCM Connectee, as with type (b) interconnections.

# LDNO charging

## LDNOs with Distribution Systems that serve Connectees 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 charges.

A LDNO with a Distribution System that qualifies as a CDCM “Designated Property” according to the definition set out in condition 13A.6 of the Distribution Licence is eligible for portfolio discounts calculated using a price control disaggregation model (method M) consistent with the CDCM, with any subsequent adjustment applied in respect of Eligible Bad Debt pass-through costs as defined in paragraph 101 of Schedule 16.

A LDNO with a Distribution System that qualifies as an EDCM “Designated EHV Property” according to the definition set out in condition 13B.6 of the Distribution Licence is are eligible for discounts calculated using an “extended” price control disaggregation model (extended method M), with any subsequent adjustment applied in respect of Eligible Bad Debt pass-through costs as defined in paragraph 101 of Schedule 16.

## A LDNO with a Distribution System that qualifies as an EDCM “Designated EHV Property” could itself have Connectees who would fall under the scope of the EDCM. Since the EDCM is a locational charging method, the host DNO Party would calculate EDCM charges at the DNO Party’s boundary for each EDCM-like Connectee on the LDNO’s Distribution System. No discounts are calculated for such EDCM Connectees as the DNO Party’s charges are based only on the specific site’s equivalent use of the DNO Party’s Distribution System.

# Calculation of LDNO Discounts

## The discount percentages are determined in accordance with Schedule 29, which is deemed to form part of this EDCM (as if it were set out herein).

## In each case, the discount applied to all CDCM tariff components. Discount percentages are capped to 100 per cent.

## ***Option A***

Following the application of discount percentages, Eligible Bad Debt pass-through costs are allocated by applying a unit charge adder (p/kWh) to all demand tariffs, as calculated under paragraph 101 of Schedule 16.

***Option B***

Following the application of discount percentages, Eligible Bad Debt pass-through costs are allocated by applying a unit charge adder (p/kWh) to the following customer groups, as calculated under paragraph 101 of Schedule 16:

* LDNO HVplus: Domestic Unrestricted;
* LDNO EHV: Domestic Unrestricted;
* LDNO 132kV/EHV: Domestic Unrestricted;
* LDNO 132kV: Domestic Unrestricted;
* LDNO 0000: Domestic Unrestricted;
* LDNO HVplus: Domestic Two Rate;
* LDNO EHV: Domestic Two Rate;
* LDNO 132kV/EHV: Domestic Two Rate;
* LDNO 132kV: Domestic Two Rate;
* LDNO 0000: Domestic Two Rate;
* LDNO HVplus: Domestic Off Peak (related MPAN);
* LDNO EHV: Domestic Off Peak (related MPAN);
* LDNO 132kV/EHV: Domestic Off Peak (related MPAN);
* LDNO 132kV: Domestic Off Peak (related MPAN);
* LDNO 0000: Domestic Off Peak (related MPAN);
* LDNO HVplus: LV Network Domestic;
* LDNO EHV: LV Network Domestic;
* LDNO 132kV/EHV: LV Network Domestic;
* LDNO 132kV: LV Network Domestic;
* LDNO 0000: LV Network Domestic.

***Option C***

Eligible Bad Debt pass-through costs are allocated by applying a fixed charge adder (p/day) to all metered demand tariffs, as calculated under paragraph 101 of Schedule 16.

***Option D***

Eligible Bad Debt pass-through costs are allocated by applying a fixed charge adder (p/day) to the following customer groups, as calculated under paragraph 101 of Schedule 16:

* LDNO HVplus: Domestic Unrestricted;
* LDNO EHV: Domestic Unrestricted;
* LDNO 132kV/EHV: Domestic Unrestricted;
* LDNO 132kV: Domestic Unrestricted;
* LDNO 0000: Domestic Unrestricted;
* LDNO HVplus: Domestic Two Rate;
* LDNO EHV: Domestic Two Rate;
* LDNO 132kV/EHV: Domestic Two Rate;
* LDNO 132kV: Domestic Two Rate;
* LDNO 0000: Domestic Two Rate;
* LDNO HVplus: LV Network Domestic;
* LDNO EHV: LV Network Domestic;
* LDNO 132kV/EHV: LV Network Domestic;
* LDNO 132kV: LV Network Domestic;
* LDNO 0000: LV Network Domestic.

## Not used.

## Not used**.**

## Not used.

## Not used.

## Not used.

## Not used.

## Not used.

## Not used.

## Not used.

## Not used.

## Not used.

## Not used.

## Not used.

## Not used.

## Not used.

## Not used.

# Portfolio EDCM tariffs for Connectees in the EDCM

## For Connectees on a LDNO’s Distribution System that would be covered by the EDCM if they were on the DNO Party’s Distribution System, the EDCM is applied to calculate a portfolio EDCM charge/credit for each such Connectee.

## These EDCM portfolio charges would be calculated as if each EDCM Connectee on the LDNO’s Distribution System were notionally connected at the boundary between the DNO Party and the LDNO; except for LDNO UMS tariffs, which are charged by reference to the voltage of the Points of Connection that provide the majority of the energised domestic connections for the LDNO in the GSP Group (or, where there is no such majority, on such other reasonable basis as the DNO Party determines). Both EDCM import and export charges will apply.

## For the purposes of calculating the boundary-equivalent portfolio EDCM tariffs, each EDCM Connectee on the LDNO’s Distribution System would be assigned the demand Connectee category determined by reference to that LDNO Distribution System’s Point of Common Coupling. The demand Connectee category is assigned as per Table 3 in paragraph 15.6.

## Such Connectees would attract charges (credits) in respect of any reinforcements caused (avoided) on the DNO Party’s Distribution System only, i.e. any network Branches that are on the LDNO’s Distribution System would be attributed a zero LRIC charge/credit.

## The setting of final charges to Embedded Designated EHV Properties including the calculation of charges for assets used on the LDNO’s Distribution System will be established by the LDNO.

## All EDCM charges would be calculated using “boundary equivalent” data provided by the LDNO to the host DNO Party 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 Party - LDNO boundary, for each EDCM Connectee, after taking into consideration the diversity and losses within the LDNO’s Distribution System. 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.

## The EDCM will include in the charges for Embedded Designated EHV Properties a fixed charge relating to any assets on the DNO Party’s Distribution System that are for the sole use of a LDNO Party's Distribution System. The assets on the DNO Party’s network that are for the sole use of a LDNO Distribution System are defined as the assets in which only consumption or output associated with Embedded customers on the LDNO Distribution System can directly alter the power flow in the asset, taking into consideration all possible credible running arrangements, i.e. all assets between the asset ownership boundary and the LDNO Distribution System’s Point of Common Coupling are considered as sole use assets. These fixed charges would be calculated in the same way as it would be for EDCM Connectees connected directly to the host DNO Party’s Distribution System.

## In calculating charges for assets on the DNO Party’s Distribution System that are for the sole use of a LDNO’s Distribution System, DNO Party’s 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 Connectee to the capacity at the LDNO - DNO Party boundary.

## If there are no Embedded Designated EHV Properties on the LDNO’s Distribution System, no sole use asset charges would apply.

## Demand scaling would be applied as normal to any EDCM portfolio tariff in respect of an EDCM Connectee. For the purposes of scaling, all EDCM Connectees connected to the LDNO’s Distribution System will be treated as notional EDCM Connectees connected to the DNO Party’s Distribution System with a Point of Common Coupling at the LDNO Distribution System’s Point of Common Coupling.

## For EDCM Connectees connected to the LDNO’s Distribution System, the capacity-based charge for the DNO Party’s indirect costs and the 20% share of residual revenue that is applied as a fixed adder, would be scaled down by a factor of 50 per cent, however, the scaling down will not apply where the residual revenue is negative.

# Offshore networks charging

## The DNO Party will treat offshore networks connected to the DNO Party as if they were EDCM Connectees.

## The DNO Party will apply the EDCM to calculate an import charge and an export charge based on capacity at the boundary and power flow data metered at the boundary.

## Any sole use assets specific to the offshore network are charged as a p/day sole use asset charge calculated as applicable to a normal EDCM Connectee.

## Demand scaling will also be applied.

# DNO Party to unlicensed networks

## 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.

## Otherwise, the DNO Party applies the EDCM to calculate an import charge and an export charge based on capacity and power flow data metered at the boundary. Any sole use assets specific to the unlicensed network are charged as a p/day sole use asset charge calculated as applicable to a normal EDCM Connectee.

# Derivation of ‘Network Use Factors’

Step 1:

## Powerflow analysis is used to determine the change in powerflow in each Branch (in MW) that is caused by a change in load (in MW) at each node in the EHV network model, that represents either EDCM demand or CDCM demand at the EHV/HV boundary.

## In essence, a change in load of X MW is applied at the node under consideration and changes in powerflow in each network Branch are identified. If the change in powerflow in a particular Branch is Y MW, as a result in the change in load at the node under consideration, then the ‘Change In Branch Flow per Change In Demand’ is given by:-

Abs (Y/X) (MW Branch flow per MW of demand at node)

## The effects of a change in demand at each node, upon the powerflows in Branches, are evaluated for each node in turn.

## The method of evaluating the ‘Change in Branch Flow per Change in Demand’ shall be the Incremental Method, described below:

# Incremental Method:

## Establish the ‘base case’ powerflow in each Branch using a network model constructed with demand data used to represent the Maximum Demand Scenario analysed in the marginal cost calculation, using Maximum Demand Data that represents the regulatory year that use of system charges are being calculated for.

## Apply a 0.1MW (at 0.95 lagging p.f.) increment to each node, in turn, in the EHV network model (at nodes that represent either an EDCM Connectee or CDCM demand at the EHV/HV boundary) and identify the change in powerflow (in MW) in all Branches where the change exceeds both 1kVA and 0.01% of the ‘base case’ powerflow in the Branch. The change in Branch flow corresponding to a 0.1MW increment at a node can be evaluated by actual application of an increment to the network model, or through the use of sensitivity coefficients. Prior to the application of the increment all the transformer tap positions, distributed generation outputs and switched shunt values are fixed to the values determined in the ‘base case’ powerflow to prevent change in their values when analysing the power flows with the increment applied.

## This calculation is performed upon the Authorised Network Model and only considers normal running arrangements.

Step 2:

## The ‘MW usage’ of each Branch by a given nodal demand is determined by multiplying the relevant value of ‘Change In Branch Flow per Change In Demand’ (derived in step 1) by the demand at the node (MW) as used in the Maximum Demand Scenario for the marginal cost calculation, using the Maximum Demand Data that represents the regulatory year that use of system charges are being calculated for. This will always be a positive quantity.

Step 3:

## For each Branch, the ‘total MW usage’ of the Branch by all nodal demands is determined by summating the ‘MW usage of the Branch’ by each node (as determined in step 2).

Step 4:

## Each nodal demand’s proportionate usage of a Branch is determined using the equation below:

Alloc (£/year) = ([MW usage] / [Total MW usage]) \* (Abs [Max contingency flow] / [Rating]) \* AMEAV

If the Branch is “generation-dominated”, or (2 \* Abs [Base flow load]) ≤ Abs ([Base flow] - [Base flow load]), then use:

Alloc (£/year) = ([MW usage] / [Total MW usage]) \* (Abs [Max contingency flow] / [Rating]) \* Abs ([Base flow load] / [Base flow]) \* AMEAV

Where:

* Alloc is the allocation of the AMEAV of the asset to a demand user in £/year
* MW usage is the absolute value of the “MW usage” of the asset attributable to that demand user (expressed in MW)
* Total MW usage is the sum of the absolute values of the “MW usage” of all demand users of that asset (expressed in MW)
* Max contingency flow is the maximum post-contingent flow through the asset in MVA. The maximum post-contingency asset flows may be extracted from the ‘locational’ analyses.
* Rating is the unadjusted rated capacity of the asset in MVA
* Base flow load is the algebraic sum of power flows through the Branch due to demand only in MW.
* Base flow is the aggregate power flow through the Branch under normal network operation in MW.
* AMEAV is the annualised modern equivalent asset value in £/year of that asset.
* The ratio ([Max contingency flow] / [Rating]) is called the asset utilisation factor and it is capped at 1.

## The quantity (Abs [Max contingency flow] / [Rating]) \* Abs ([Base flow load] / [Base flow]) is called the load utilisation factor.

## Sole use assets are not to be included in the calculation of the MEAV of the Branches and consequently some Branches may have an MEAV of zero.

Step 5:

## For each node, the £/annum ‘usage’ of Branches (calculated in Step 4) of the same voltage level, by the demand at the node, are summated to create a total £/annum for each voltage level for the nodal demand. The considered voltage levels correspond to those used in the CDCM and include voltage levels that represent transformation between two voltages. These voltage levels are ‘132kV’, ‘132kV/EHV’, ‘EHV’, ‘EHV/HV’ and ‘132kV/HV’.

## For each node where EDCM demand is present, the total £/annum ‘usage’ of Branches of each voltage level, for the node, is divided by the demand at the node (in kW), as used in the Maximum Demand Scenario, to create a £/kW/annum total usage of Branches at each voltage level by the particular node. This shall be the numerator in the network use factor, for a particular voltage level, for the EDCM demand node.

## For all nodes where CDCM demand is present, and the CDCM demand is considered to be ‘dominant’ at the node (CDCM demand shall be considered to be ‘dominant’ where the DNO Party estimates that the maximum demand associated with all CDCM demand at the node exceeds the maximum demand associated with all EDCM demand at the node), the £/annum ‘usages’ of Branches at each voltage level (calculated in Step 4) are summated to create a total £/annum ‘usage’ for all CDCM dominated nodes. The CDCM demand ‘using’ each voltage level is determined by summating the nodal demands of all CDCM dominated nodes that have non zero £/annum ‘usages’ at the particular voltage level. The average £/kW/annum network usage by CDCM dominated nodes is derived for each voltage level by dividing the total £/annum usage (at the voltage level by CDCM dominated nodes) by the total CDCM demand ‘using’ the voltage level. This provides the denominators used for the network use factors.

## The network use factor, at each voltage level, for each node where EDCM demand is present therefore is the £/kW/annum for the nodal demand at the appropriate voltage level, divided by the corresponding average £/kW/annum for the same voltage level determined for CDCM dominated nodes.

1. Guidance on creation of a suitable network model is provided in section 4Authorised Network Model of Annex 1. [↑](#footnote-ref-1)
2. Guidance on the power-flow analysis required to consider these conditions is provided in sections 6.3 and 6.10 of Annex 1. [↑](#footnote-ref-2)
3. Guidance on the demand data required to represent the maximum demand period is provided in section 5.31 of Annex 1. [↑](#footnote-ref-3)
4. Guidance on the application of diversity to demand data is provided in section 5.11 of Annex 1. [↑](#footnote-ref-4)
5. Guidance on the demand data required to represent the minimum demand period is provided in section 5.37 of Annex 1. [↑](#footnote-ref-5)
6. Guidance on the generation data required to represent the maximum demand period is provided in section 5.31 of Annex 1. [↑](#footnote-ref-6)
7. Guidance on the generation data required to represent the minimum demand period is provided in section 5.37 (of Annex 1 [↑](#footnote-ref-7)
8. Guidance on suitable cleansed demand data is provided in section 5.2 of Annex 1 [↑](#footnote-ref-8)
9. Guidance on the derivation of Security Factors is provided in section 6.6 of Annex 1. [↑](#footnote-ref-9)
10. Guidance on the Contingency Analysis used in the derivation of Security Factors is provided in section 6.4 of Annex 1. [↑](#footnote-ref-10)