Access and Forward-looking Charges

Locational Granularity of Charging

Locational Granularity Subgroup

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Related Documents

Reference 1	Electricity Industry Access and Forward-Looking Charging Review - Significant Code Review launch statement and decision on the wider review – Ofgem publication
Reference 2	

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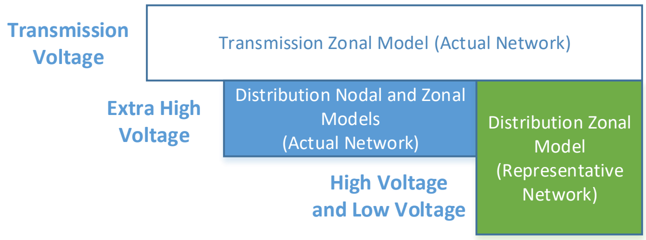
1 Executive Summary

1.1 This report will inform the Ofgem led Electricity Network Access and Forward-looking Charging Significant Code Review ('the Access SCR') and is one of a suite of reports produced by the Access SCR Delivery Group, this particular report is focusing on the locational granularity of forward-looking charges.

1.2 The report firstly considers the current forward-looking charging regimes applied across distribution and transmission. Under current transmission arrangements, these are derived from a zonal model for all customers' use of the transmission network (derived from an underlying nodal model). At distribution, both nodal and zonal actual network models are used for EHV (Extra High Voltage) customers' use of the distribution network. A zonal representative network model is used for HV (High Voltage) and LV (Low Voltage) customers' use of the distribution network. These arrangements are illustrated in Figure 1.

Figure 1: Representation of modelling determined by voltage of connection of customer



1.3 This approach creates boundary changes in the charges which a user faces depending on where they connect to the network, which are not always reflective of the different cost drivers, but are more directly related to the differences between charging methodologies.

1.4 Whilst a use of system charging methodology boundary exists between transmission and distribution, differences at the boundary are driven not only by the ongoing use of system charge, but also the connection charging arrangements (which also differ. A prospective connectee may have to assess, for example, the trade-off between a lower use of system charge liability with higher upfront capital costs, or a higher ongoing use of system charge liability with lower upfront capital costs. This will vary depending on which network they connect to. The differences in connection charging arrangements are not further explored in this report, but should be noted for future work planned under the SCR on the connection charging boundary.

1.5 The principal boundary issue that has been identified is between the EDCM (Extra high voltage Distribution Charging Methodology) and CDCM (Common Distribution Charging Methodology), since each uses a different approach to determine the impact of a user on the same EHV network. Within the EDCM, there are also two different charging methodologies currently in use by the Distribution Network Operators (DNOs), depending on distribution network area, which vary in their locational granularity (one is nodal and the other is zonal) and in their cost model principles. The different cost models are not assessed in this report, but should be noted for future work planned under the SCR on charging cost models.

1.6 For example, a customer connecting directly to a primary substation would have charges for their use of all distribution voltages calculated under the EDCM, whereas a customer connecting to the same primary substation via a short HV circuit would have charges for their use of all distribution voltages calculated using the CDCM, which are typically very different. If one of the EDCM customers connected to the HV side of a primary substation were to instead connect via a short section of HV network in the Yorkshire area (a case study in the report), charges would increase by an average of around 200%, but could be as much as around 700% in the most extreme case. This is unlikely to be reflective of the additional cost incurred by the DNO in providing a small section of HV network. Whilst it has not been possible to conduct a similar assessment of the boundary between distribution and transmission voltages for this report, it is proposed that this would be a valuable exercise as part of next steps.

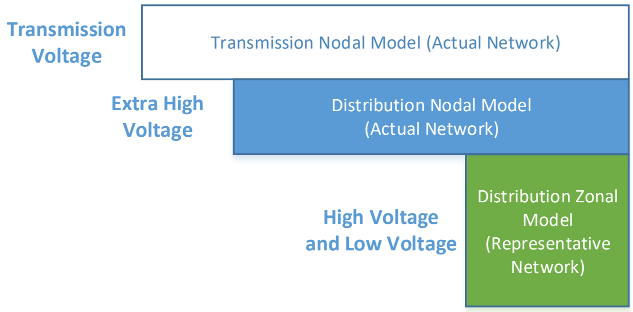
1.7 The sub-group considered the options for extending more granular approaches, such as those applied under EDCM (including site specific charges and more granular averaged charges based on models of the actual network) to a wider range of customers at lower voltages. From examination of the information provided by all DNOs, it was determined that the data and modelling capabilities required to extend the current EDCM approaches (or a similar approach) to the HV network are not currently available nor expected to be available in the foreseeable future, rending this approach infeasible. Even if this capability were available, it is doubtful whether increasing the number of customers covered by this approach by a factor of 10 (from around 2,400 to over 24,000 across GB) is a practical proposition.

1.8 The sub-group also considered options for extending less granular approaches, such as those applied under CDCM (charges based on representative network models for all voltages). This option would certainly be feasible as it is a variant on the status quo for CDCM customers, and could be developed in a way which increases locational granularity at HV and LV (for example by introducing a number of different representative networks models within each licence area). But for customers connected at HV Sub and above (i.e. EDCM customers), this approach gives less locational granularity than the status quo and so is not considered further in this report. Despite not being the subject of further consideration in this report, this option may be worthy of consideration when other factors (such as stability of charges) are considered in the subsequent cost modelling work.

1.9 This report concludes that a nodally granular signal is only feasible for customers connected to the network at EHV, though existing different approaches could be unified and improved. The report also concludes that linking the locational signal for HV and LV connected customers to the upstream primary substation(s) to which they are most directly connected could improve locational granularity, without extending nodal network modelling into those HV and LV networks

1.10 Linking the locational cost signal to upstream network layers provides a method which could reduce the adverse boundary effects highlighted above, whilst also increasing locational granularity without imposing an unfeasible requirement for additional modelling and data processing capabilities. Below the point of nodal assessment of the actual network, a zonal approach using a representative network model could be used (particularly if network data/models of the actual network are not available at lower voltages). This is illustrated in Figure 2. Note that whilst transmission arrangements have been marked as a 'nodal' model on this figure, it would also be possible to maintain the principle of linking to upstream locational signals under a zonal charging model with reduced locational granularity.

Figure 2: Representation of modelling determined by the voltage of assets used by the customer



1.11 Approaches for producing the distribution representative zonal models could include any combinations of:

- separate representative zonal models for each primary substation;
- a single representative zonal model for each licensee (e.g. extending CDCM to cover EDCM customers);
- regional models defined by various geographical factors (i.e. geographical location); and
- archetypical models based on network loading or customer/network characteristics.

1.12 For the first approach, it was deemed likely that many primaries will have very similar mixes of assets and customers, so modelling of all primary substations is unlikely to be a proportionate approach to locational charging. Use of archetypal network models (including grouping primaries by region or type) may deliver a similar outcome for far less computational resource.

1.13 For the second option, other options considered in this report have the potential to deliver much greater locational granularity, and so this option was not considered in further detail. Whilst extending a CDCM type of approach to cover EDCM customers would entail less locational granularity, there may be merit in considering this approach in the subsequent cost models work, as it could result in a more stable charge (than the current EDCM charges) based on a representative network approach for all distribution network users.

1.14 The report's initial feasibility assessment therefore focussed on variants of the third and fourth approaches, which could both introduce greater granularity into the forward-looking element of use of system charges and were identified as feasible options. In assessing these options, the sub-group developed the following criteria to determine whether a particular approach was practical and proportionate:

a) Data availability – the data needed to produce the various models;
b) Data processing – the computational effort needed to produce the various charges; and
c) Data accuracy – the extent to which data used to populate the models is real data, or heavily reliant on forecasts and assumptions.

1.15 The initial assessment of two options using a single approach across all voltages and three options which combine nodal and representative approaches is summarised in Table 1 (criteria for RAG assessment outlined in paragraph 2.10).

Table 1: Practical and proportionate assessment of locational charging options

Option	Data Availability	Data Processing	Data Accuracy
Nodal charging for all customers and all voltages	R	R	R
Representative modelling for all customers and all voltages	G	G	G
Nodal for EHV networks and representative geographic regional for HV and LV networks	A	A	A
Nodal for EHV networks and representative archetypical (level of loading) for HV and LV networks	G	A	A
Nodal for EHV networks and representative archetypical (customer characteristics) for HV and LV networks	G	G	A

1.16 At this stage of the SCR work, it is not possible to develop further detail on specific variants of these options, which may vary in assessment rating, given that further refinement and specifics can only be developed once there is a clearer understanding of:

- the cost drivers that need to be accounted for in the cost models;
- the cost modelling approach (to be considered in Ofgem's academic review and subsequent cost model work) and the resulting data requirements for deriving the forward-looking charge;
- the desirability and acceptability of very granular charges, particularly to domestic and smaller users; and
- a clear cost benefit analysis to establish the value delivered by a move to such levels of granularity.

1.17 Finally, there is an apparent mismatch in the creation of more locationally granular charging signals with the requirement/ability for suppliers to pass through those signals to network users. Presently, suppliers could choose to average any locational cost signals across their entire customer base, as they are not obliged to pass these locationally granular charging signals on to network uses. This would appear to undermine much of the benefit associated with introducing greater granularity into distribution charges. An assessment of whether any of these proposals would be effective should be fully justified and evaluated before complex and potentially costly changes are introduced. It is recognised that alternatives to the supplier-led model may emerge which may encourage more granular charges to be passed through to end-customers, for example more service orientated versions in which services are traded. However, it is expected that the granular charges would be visible to those who are able to respond to the signals and hence able to influence network costs.

2 Introduction

Significant Code Review

2.1 This report has been produced as part of Ofgem's Electricity Network Access and Forward-Looking Charging Review Significant Code Review ('the SCR'). The SCR Delivery Group established a sub-group focused on the locational granularity of forward-looking charges to produce this report, developed in accordance with a Product Descriptor provided by Ofgem. This was identified as a necessary foundational piece of work that will be important in helping to shape the charging and access rights options considered under the SCR.

SCR Guiding Principles

2.2 Ofgem has specified that proposals developed under the SCR will be assessed against three guiding principles:

1. Arrangements support efficient use and development of the energy system;
2. Arrangements reflect needs of consumers as appropriate for an essential service; and
3. Changes are practical and proportionate.

2.3 This report focusses primarily on the first and third of these, with the second to be considered in due course by a sub-group focussing solely on the implications of proposed changes for smaller users. This sequencing will enable more detailed options development to take place so that the impact of more locationally granular charging arrangements on smaller users can be more fully assessed.

2.4 The report is predicated on Ofgem's view that more efficient use and development of the energy system will be supported by charges which are more cost-reflective. A more locationally granular approach to network charges can improve cost-reflectivity, as network charges will be more bespoke to individual network users, and the impacts of their behaviour on network costs. Whilst additional locational granularity may be desirable to achieve improved cost-reflectivity, the options may be restricted by the practicalities of network data and user information that is readily available, or could be acquired. This is particularly true for users connected to the HV and LV networks, where currently granular data and models may not exist or be readily available.

Scope

2.5 In the Product Descriptor provided by Ofgem, the sub-group was asked to consider the options available to increase the locational granularity of forward-looking DUoS (Distribution Use of System) charges. These range from:

- Charges based on an accurate model of the networks – considering the example of the TNUoS (Transmission Network Use of System) transport model (which includes factors such as distance, asset type and capacity). Charges based on grouping of areas and/or branches of the network into different categories, particularly where insufficient information may be available for a more granular approach, e.g. urban/rural/industrial/residential areas. Charges based on measures of how fully utilised different assets/branches of the network are, how this may change, and the driver for this (e.g. generation-dominated vs demand-dominated areas).

2.6 These options could apply to, for example, EHV only, HV only, HV and LV, or other justifiable hybrid approaches or alternative methods of user or network segmentation that reflect network cost drivers.

2.7 The Product Descriptor tasked the sub-group with:

- Outlining the key options for increased granularity of charges at HV and LV (given that nodal granularity is already available at EHV).
- Establishing limitations imposed by the availability of data and models for the HV and LV networks (taking into account planned developments in network monitoring and/or other improvements in availability of network or user data).
- Where data and models are not presently available, establish the feasibility of obtaining this information or developing improvements in available data and modelling, and in broad outline terms establish the time/costs involved.
- *****Conducting an assessment of how different options for the level of granularity could achieve greater/lesser cost reflectivity through different approaches, highlighting where options:
  - support additional locational granularity where the cost drivers work suggests that there are significant variations in costs; or
  - may provide unnecessary additional granularity where the cost drivers work suggests that costs are relatively uniform across different areas.
- Establishing where options would maintain or create different approaches at different voltages, areas or according to different user types, and assess the options for interactions between these approaches.

2.8 *****It should be noted that in the initial scope and sequencing of work, as set out in the Product Description (Annex 4), the detailed cost-reflectivity assessment aspects of this report were dependant on the conclusions of the cost drivers report. Due to delayed conclusions from the cost drivers sub-group, it was not possible to conduct this detailed assessment in this report. It is anticipated that further work will now be required to develop and assess more specific options for locationally granular charging, based on additional work to understand locational variance in cost drivers and the different potential approaches to cost modelling.

2.9 This report instead focuses primarily on the structural cost-reflectivity issues associated with the charging methodologies and their interactions, and conducts a high level appraisal of the feasibility of conceptual approaches to more locationally granular charges.

Practical and Proportionate Assessment Criteria

2.10 In assessing the feasibility of options the sub-group developed the following criteria to determine whether a particular approach was practical and proportionate in the context of the task:

1. **Data availability** – This covers the data needed to produce the various models. As the academic work has yet to indicate how charges are to be calculated, at this stage it is assumed that data requirements for nodal approaches are similar to that required for the EDCM and for the representative models similar data to the CDCM (but assessed as to whether it is available at the envisaged level of granularity rather than at a total DNO area level). Assessment categories are defined as:
   - **Green**: already or readily available;
   - **Amber**: not currently collected but could be obtained; and
   - **Red**: not currently collected and difficult to obtain.
2. **Data processing** – This covers the computational effort needed to produce the various charges. As above, as the academic work has yet to indicate how charges are to be calculated, it is assumed that power flow modelling is used for nodal prices and Excel for the representative models. Assessment categories are defined as:
   - **Green**: modelling capabilities already exist or readily available;
   - **Amber**: not currently available but existing capability could be expanded at minimal cost; and
   - **Red**: no current capability or not practical due to issues such as processing time or no automated analysis software available.

3. **Data accuracy** – the extent to which data used to populate the models is real data or heavily reliant on forecasts and assumptions. Assessment categories are defined as:
   - **Green**: data, whilst not necessarily 100% accurate, allows for definite calculation of costs and other determining factoring that affect which models apply;
   - **Amber**: some data sets available but over 25% of the data is expected to rely on assumptions and estimates; and
   - **Red**: most of the data in the models will rely on assumptions and estimates.

Report Structure

2.11 The report begins with an overview of the current locational charging arrangements, including the network structure and billing arrangements. High-level cost modelling options are then described before considering the options to extend any of the approaches currently in use at some voltage levels to cover all voltages.

2.12 Consideration is then given to ways in which different approaches could be combined under a hybrid approach, which leads to an assessment of feasible options. Finally, a 'next steps' section has been included, which includes some of the sub-groups considerations on how the approaches described could be taken forward.

2.13 Annexes to support the body of this report include: a glossary, an overview of previous work undertaken on locational charging, and relevant extracts from the network company responses to an Ofgem request for information conducted in January 2019.

Exclusions

2.14 Cost-reflectivity is a desired outcome of any change to locational charging; where users pay cost-reflective charges they are more able to respond to the relative signals provided by the charge, and take appropriate actions which may benefit them and the network. There are many potential ways of increasing locational granularity and whilst this report will assess the feasibility of the options, the desirability of those options is not considered. The purpose of this report is to assess the ability of feasible locational charging options to improve cost-reflectivity only. Ofgem's broader statutory duties include having due regard to different groups of domestic consumers, including those residing in rural areas, and as such whilst this report discusses the practicability of changing charging arrangements based on a site's geographic or electrical location, it is for the Gas and Electricity Markets Authority to consider separately the extent to which those changes are appropriate. This report therefore does not consider the overall desirability of locational charging options, as this will be assessed at later stages within the SCR process.

2.15 The report does not take account of the work on charging being undertaken for Ofgem with independent academia or any other sources of information and it is assumed that the outputs of that work will not impose significantly new data requirements.

2.16 The report does not consider any consequential impacts on IDNOs (Independent Distribution Network Operators) charging, which will be considered subsequently by Ofgem at a later stage of the SCR work programme.

Dependencies

2.17 This report refers to information from the following information sources:
- data provided by network companies to Ofgem in response to a request for information ('the RFI') in January 2019. This data has been used to inform the feasibility assessment of each option; and

- initial conclusions of the cost drivers workgroup, which has progressed in parallel with the work of the locational charges workgroup. The output from that workgroup has informed a high level view of each feasible option's potential to improve cost-reflectivity by highlighting the extent to which cost drivers are locational and/or attributable to users. Per comments in paragraph 2.8 regarding scope, detailed cost drivers information was not available at the time of drafting this report.

2.18 This report is expected to inform subsequent work under the SCR on:

- further detailed options development based on the locational granularity of network cost drivers;
- further work to develop and assess cost model options following Ofgem's work with academia;
- options to change the connection charging boundary. Ofgem highlighted in the SCR launch that changes to the connection charging boundary are *"dependent on better locational signals being sent through ongoing distribution use of system charges"*; and
- the impact of proposed changes on small users, where highly locational charges may have undesirable effects.

3 Current Charging Regime

Section Summary

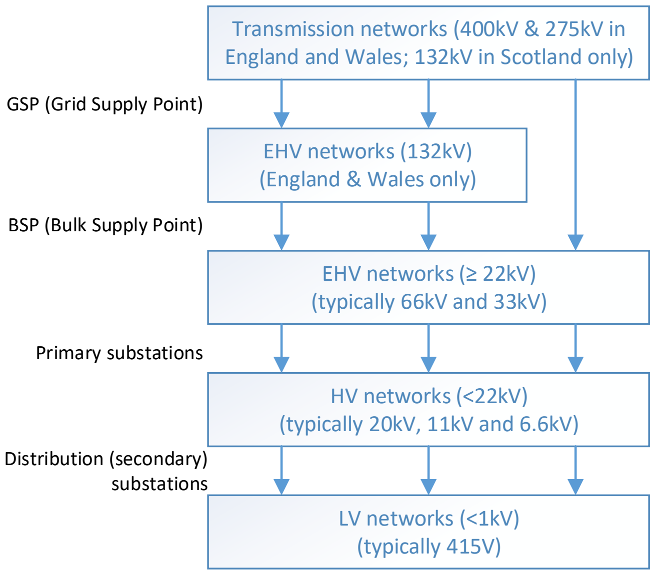
3.1 This section describes the physical structure of the electricity networks, the commercial arrangements which underpin existing network charging, and the existing ways in which locational charges are determined. It is split into four sections, covering:

- an explanation of the topology of the network;
- the commercial arrangements for billing transmission and distribution charges;
- the way in which locational charges are calculated under the existing arrangements; and
- work on locational charging options conducted under previous reviews.

Structure of Networks

3.2 Figure 3**Error! Reference source not found.** gives a diagrammatic representation of the transmission and distribution networks.

Figure 3: Representation of transmission and distribution networks



3.3 Power is transmitted from large power stations to the DNOs over the transmission networks, which are at 400kV and 275kV in England and Wales, and 400kV, 275kV and 132kV in Scotland. The connection points from the transmission networks to the DNOs are known as GSPs (Grid Supply Points).

3.4 In England and Wales, the DNOs distribute power from the GSPs to BSPs (Bulk Supply Points) via 132kV networks. BSPs then transform from 132kV down to EHV. In Scotland, GSPs connect the transmission network to EHV.

3.5 EHV networks then connect to a primary substation, where the voltage is reduced down to HV. HV networks run to the distribution (secondary) substations which reduces the voltage down to LV. Nearly all domestic customers are connected to the LV network.

3.6 Table 2 shows the number of transformers at each voltage level in GB, as reported DNOs in July 2018. Note that higher voltage substations (i.e. those at 132kV/EHV and EHV/HV) typically have two transformers to ensure continuity of supply should one transformer fail. Hence, the number of BSPs and primaries is roughly half the number of transformers.

Table 2: Number of transformers at each voltage level[1]

Transformer Voltage	GB Count
BSP – 132kV/EHV	2,016
Primary – EHV/HV	10,731
Distribution – HV/LV	594,576

3.7 Customers and generators are connected at all voltage levels, primarily determined by their power requirements. Table 3 shows the number of customers connected at each voltage, the count of generators connected at each voltage level, and the total demand and generation capacity connected at each voltage level.

Table 3: Count of customers and capacity connected at each voltage level[2]

<table>
<tr><th>Voltage of Connection</th><th>Customer Count</th><th>Generator Count</th><th>Sum of Agreed Import Capacities (MVA)</th><th>Sum of Agreed Export Capacities (MVA)</th></tr>
<tr><td>GSP</td><td>152</td><td>123</td><td>2,965</td><td>4,075</td></tr>
<tr><td>132kV Network</td><td>211</td><td>152</td><td>3,127</td><td>8,434</td></tr>
<tr><td>132kV/EHV Substation</td><td>281</td><td>171</td><td>3,029</td><td>3,785</td></tr>
<tr><td>EHV Network</td><td>1,398</td><td>1,332</td><td>2,196</td><td>12,828</td></tr>
<tr><td>EHV/HV Substation</td><td>371</td><td>92</td><td>2,041</td><td>521</td></tr>
<tr><td>HV Network</td><td>24,104</td><td>3,514</td><td>22,975</td><td rowspan="3">9,824</td></tr>
<tr><td>HV/LV Substation</td><td>10,392</td><td>448</td><td>3,064</td></tr>
<tr><td>LV Network</td><td>30,777,150</td><td>11,527</td><td>Not available</td></tr>
<tr><td>Total</td><td>30,814,059</td><td>17,360</td><td></td><td>39,467</td></tr>
</table>

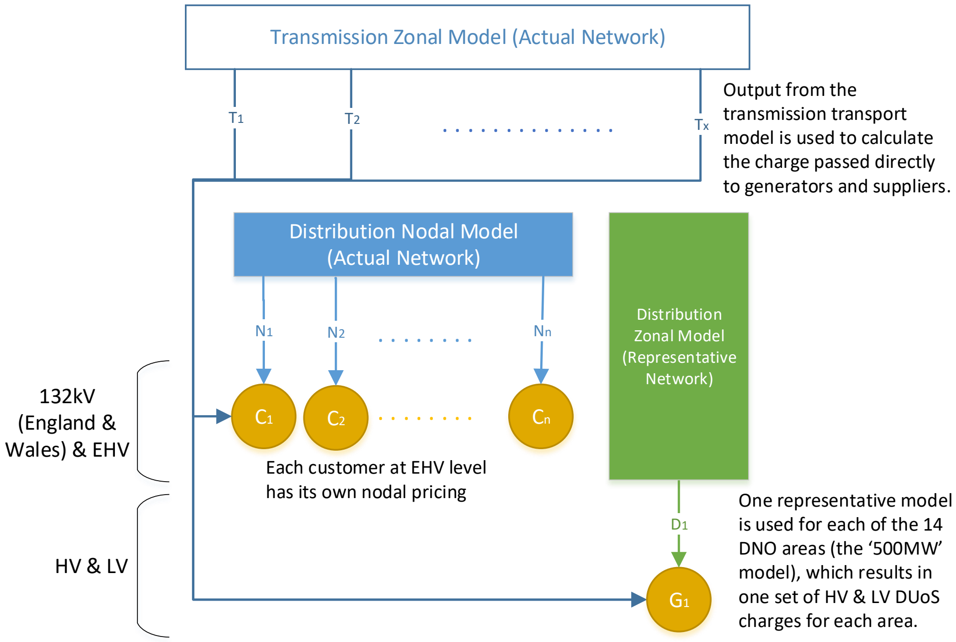
<u>Commercial Structure</u>

3.8 Figure 4 gives a diagrammatic representation of the mechanisms by which charges for a given customer are derived, albeit in the vast majority of cases the charges themselves are levied on electricity suppliers.

[1] Source: DNO 2017/18 Regulatory Reporting Submissions to Ofgem

[2] Source: EHV/HV substation and above – provided by DNOs based on data from 2019/20 EDCM models; HV and below customer counts, HV and HV/LV substation demand capacities – extracted from DNOs published 2019/20 CDCM models; HV and below capacities – derived from DNO responses to the RFI (which included total generation capacity) less EDCM generation capacity.
Notes: The count of generators only includes those with an export MPAN so excludes 'behind the meter' generation (i.e. that which only offsets demand) and excludes small installations which are allowed to 'spill' onto the networks without being metered (e.g. Feed in Tariff installations). LV agreed demand capacity has not been included as DNOs do not agree capacities with NHH or HH aggregate settled customers, representing the vast majority of LV connected demand customers.

Figure 4: Diagrammatic representation of commercial arrangements



3.9 Different commercial arrangements are in place for the billing of transmission and distribution charges.

3.10 Transmission charges for distribution connected users are charged and billed to either the end user's supplier[3] via Transmission Use of System charges (TNUoS) or to the DNO via Electricity Transmission Connection Charges ("exit charges"). The supplier is under no obligation to replicate the network operators charging structure in their tariffs to end users – for example, for half-hourly site specific customers, the red, amber and green unit rate structure which DNOs apply in tariffs for suppliers is often not reflected in suppliers' retail tariffs.

3.11 The supplier can choose whether to pass the use of system tariff through, based on the level of risk they are holding and the impact that it may have on their end user tariffs. For example, if the risk perceived by suppliers is high then they may alter their charging structure to end users to reflect that. Alternatively, suppliers may choose to change their tariffs in a manner which is attractive to new and existing customers. This may have the effect of reducing the effectiveness of the pricing signal that granular network charges may deliver.

3.12 DNOs currently have two different charging methodologies to calculate Distribution Use of System (DUoS) charges, the EHV Distribution Charging Methodology (EDCM) and the Common Distribution Charging Methodology (CDCM). Exit charges are passed on to customers via DNOs' DUoS charges.

3.13 Under EDCM and CDCM charging arrangements there is no pass through of EDCM costs to CDCM users from one methodology to the next. The EHV network costs associated with delivering electricity to CDCM customers are derived under an entirely different method to that used to derive EHV network costs for EDCM customers.

[3] A small number of larger sites are billed directly

Current Locational Charging Methodologies

3.14 There are currently three charging methodologies across the transmission and distribution networks. The charges determined in accordance with each vary by location to some degree, albeit some only differentiate between the 14 DNO license areas. The methodologies are:

- **The transmission network charging methodology uses the transport model** to determine locational charges for use of the transmission network. Charges are calculated using an underlying nodal model, but applied on a zonal basis, where generation zones and demand zones are not the same;
- **EDCM contains two different methods for calculation of locational charges:**
  - **FCP (Forward Cost Pricing)** is used to determine locational charges for use of the distribution network (for customers connected at EHV or at a primary substation). It is based on grouping network branches into zones, where all customers in a zone face the same locational charge. Six DNO licensees use FCP.
  - **LRIC (Long-Run Incremental Cost)** is used to determine locational charges for use of the distribution network (for customers connected at EHV or at a primary substation). It is based on a nodal model, where each customer receives an individual charge. Eight DNO licensees use LRIC.
- **CDCM** determines a highly averaged zonal charge for use of the distribution network for customers connected at HV or LV. This is based on the '500MW model' that represents which of the 14 license areas a user is connected in. Charges within each area are highly averaged and vary by voltage level, but otherwise not by location.

3.15 IDNOs operate under a relative price control, meaning that the charges an IDNO applies for a domestic customer must not exceed those which the host DNO would apply. IDNOs typically ensure compliance with this by mirroring the host DNO's charges for end users connected to their networks. IDNOs charge suppliers for use of both their network and the host DNO's network. DNOs in turn charge IDNOs in respect of IDNO end customers' use of the DNO network. The CDCM includes within it the calculation of discounts which apply to the underlying CDCM tariffs to determine the charges which DNOs apply to IDNOs. Those calculations are carried out in the PCDM (Price Control Disaggregation Model). The locational granularity of charges for customers connected to IDNO networks is derived from the charges which IDNOs levy on suppliers, which typically mirror the host DNO's charges, and so are derived from the CDCM. The PCDM is simply a mechanism for determining what proportion of revenue the DNO and IDNO respectively are entitled to. It does not introduce additional locational granularity, and is therefore not considered further in detail as part of this report[4].

The Transport Model

3.16 In transmission charging, the transport model assesses the impact of network flows based on two scenarios: one where there is a high volume of intermittent generation and one where there is a high volume of controllable generation.

3.17 Under each scenario, 1MW is added at each node, and the model is re-run to show the incremental effect of the additional load. This process is repeated across each node on the network, with an expansion constant used to then derive a notional cost of transmitting 1MW over 1km. These costs are then the basis of the "wider" element of TNUoS locational charges.

[4] Note that Ofgem intends to consider the impact of the SCR on the IDNO regime under a subsequent piece of work.

3.18 As each scenario assumes different generator technology types using the network at a particular time, the output assigns different costs to conventional and intermittent generators, with the former paying, ”year round” charges as well as, “peak”, and the latter paying only the peak element. For demand charges, the same process is followed but without the distinction between peak and year round scenarios driving different charges for different demand consumers.

3.19 Separately to the wider element of generation TNUoS tariffs is the ”local circuit” charge payable by some generators, depending on their individual connection. These charges vary based on the specific circuit assets (e.g. cables or converters) and transmission substations used at a specific location.

3.20 Customers connected to the distribution networks receive TNUoS charges through their registered supplier. For distribution-connected (or, “embedded”) generation <100MW, the supplier currently receives a credit (the embedded export tariff) for gross kW half-hourly exports over triad (three half hours of peak demand). This credit is comprised of the inverse of the TNUoS Demand Locational charge and a value known as the ‘AGIC (Avoided GSP Infrastructure Cost), which is a sum determined to be the approximate value of transmission network reinforcement that was avoided by virtue of the generator connecting to the distribution network. The value of the Embedded Export Tariff is floored at £0, such that embedded generators <100MW do not pay TNUoS. Supplier and embedded generators typically have commercial arrangements to facilitate pass-through of this credit.

3.21 Embedded generators <100MW do not currently receive locational pricing signals from the Transmission network and do not contribute to the costs of it. Locational signals for demand consumers are calculated on a nodal basis, as outlined above. The aggregate value of the demand locational signal in TNUoS is comparatively small (i.e. <£100m vs. the total TNUoS value of c.£2.7bn). Distribution-connected half-hourly metered consumers’ volumes are only charged the locational element of TNUoS if they import over triad. Where a half-hourly metered consumer avoids importing over each of the three half hours of peak demand their volumes are not chargeable and therefore, they make no contribution to the cost of the transmission network.

EDCM Forward Cost Pricing (FCP)

3.22 The FCP methodology separates the network into a number of ‘Network Groups’. The FCP demand price is calculated by assessing network reinforcement cost to support a maximum of 15% demand increment for each network group over the next 10 years. The potential reinforcement cost is calculated and averaged at each voltage level within the same network group such that the total revenue recovered equates to the forecasted reinforcement cost plus a certain level of investment return. The FCP charges within a network group are the same for all the customers connected to that group.

3.23 The outputs of the FCP power flow method are a £/kVA/year “Charge 1” for every group defined in the DNO’s network. A group is either:

- 132 kV and similar circuits (a “level 1” group);
- 132 kV/33 kV and similar substations with 33 kV and similar circuits (a “level 2” group); or
- Primary substations (a “level 3” group).

EDCM Long Run Incremental Cost (LRIC)

3.24 The LRIC methodology calculates nodal incremental costs, which represent the deferred reinforcement costs caused by the addition of demand or generation at each network node. AC power flow analysis is used to take account of how a change in connectee behaviour affects the network. This enables calculations of the time needed before reinforcement is required at different points on the network and subsequently the net present value (NPV) of the future costs of reinforcement. The LRIC algorithm assumes a 1% annual growth in demand and reinforcement charges are capped to the annuitised rate over a 40 year period.

3.25 The outputs of the LRIC power flow method are a £/kVA/year local "Charge 1" and a remote "Charge 1" for each location in the model, where the local charge refers to the voltage of connection and the remote charge refers to higher voltage levels. In addition, each LRIC location may have "linked locations", in order to define clusters of up to eleven locations which are processed together.

CDCM 500MW model

3.26 Currently each DNO licensee has its own individual 500MW model. It is a hypothetical model which is intended as a means of representing a scaled version of an actual network. The use of a scaled version is possible because it is not the absolute cost at each network level that drives charges, but rather the relative cost between voltage levels.

3.27 The current hypothetical 500MW model is designed as an increment serving loads that have the same topography, diversity and other characteristics as the actual loads on the existing network. In particular, customers' locations and consumption patterns are representative of reality in the DNO's area. It reflects current design practices and assumptions for a hypothetical increment to the existing network, with the mix of assets and associated volumes generally reflecting the existing network topology.

3.28 The model essentially calculates the cost of building a representative 500MW network, with the costs allocated to the following network levels:

- 132kV circuits;
- 132kV/EHV transformation;
- EHV circuits;
- EHV/HV transformation;
- 132kV/HV transformation;
- HV circuits;
- HV/LV transformation; and
- LV circuits.

3.29 Data from the 500MW model is converted into £/kW at each network level and scaled to system simultaneous maximum load before they are used to derive tariffs. 500MW is used as it is the largest scale at which distribution networks might plausibly be planned.

PCDM (Price Control Disaggregation Methodology)

3.30 The PCDM calculates discount percentages which are applied to the DNO's underlying CDCM tariffs to determine charges which are levied on IDNOs. Different discount percentages are calculated for each DNO to IDNO boundary voltage. This is to reflect the different proportions of the network provided by the DNO and IDNO for different boundary voltages. For example, for an end user connected at LV with DNO to IDNO boundary also at LV, the discount percentage is relatively small (average 34% in 2019/20) reflecting that the host DNO provides the network from GSP to LV and the IDNO only provides part of the LV network. However, for an end user connected at LV with DNO to IDNO boundary at HV, the discount percentage is relatively large (average 57% in 2019/20) reflecting that the IDNO provides part of the HV network, the HV/LV substation and the entire LV network.

3.31 There are seven DNO to IDNO boundary voltages for which distinct discounts are calculated, because an IDNO network could connect to a DNO network at any voltage below the GSP. Under the current arrangements, for each tariff for an LV end customer, a further seven tariffs must also be published for each possible DNO to IDNO boundary voltage. Note, despite tariffs being published for all DNO to IDNO voltages, the vast majority (98%) of IDNO customers are connected to IDNO networks with DNO to IDNO voltage at HV (59%) or LV (39%).

Other drivers of EDCM charges

3.32 Alongside each of the FCP and LRIC approaches, NUFs (Network Use Factors), data from the CDCM model, and usage data for the specific customer in question is used in the calculation of EDCM charges. NUFs are a measure of the relative value of assets used by customers at different locations within the EHV network compared to usage of those assets by HV and LV customers. Every customer may have a NUF defined for each of the five network levels considered within the EDCM. These are used in order to determine unique network asset rates for every customer associated with their access to (capacity) and usage of (demand) the network.

3.33 NUFs are used alongside values derived from the 500MW model in the CDCM in the calculation of "asset-based" elements of the import capacity charges. This includes the network rates and direct operating costs, as well as an asset-based residual revenue element which currently represents 80% of the residual to be recovered from EDCM customers.

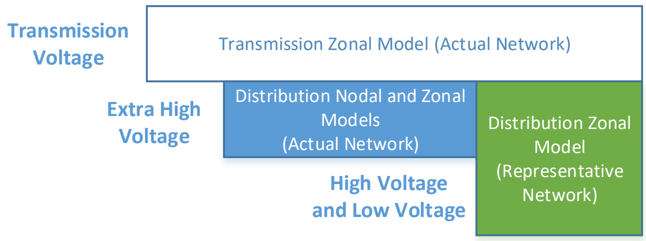
3.34 EDCM charges are viewed as being volatile but to a large extent that is not due to the unit charges as determined under the LRIC or FCP methodologies. These unit related charging elements give rise to typically less than 5% of the total EDCM revenue. Therefore, the cause of the EDCM volatility is extremely unlikely to be caused by those charges. The NUFs and other inputs are the more significant driver of overall EDCM revenue.

3.35 Residual charging is being reviewed under the targeted charging review (TCR). If Ofgem's 'minded to' decision on the TCR was implemented, this would remove the locational element of residual charging.

4 Issues with Current Approaches

4.1 Figure 5 shows how modelling approaches are combined under the status quo, with a zonal model used for all customers' use of the transmission network, a nodal or zonal model used for EHV connected customers' use of the distribution network, and a representative model used for HV and LV connected customers' use of the distribution network.

Figure 5: Representation of modelling determined by the voltage of the connection of the customer



4.2 This approach can create issues at the boundaries between methodologies. For example, customers connected relatively close to one another, and so likely to drive similar costs for the network company, can face very different charges:

- A customer connecting directly to a primary substation (i.e. a HV Sub customer with charges calculated under the EDCM) will have charges for use of the EHV and 132kV networks calculated using the nodal or zonal EDCM approach.
- A customer connecting to the same primary substation via a short HV circuit (i.e. a HV network customer with charges calculated under the CDCM) will have charges for use of the HV, EHV and 132kV networks calculated using the representative 500MW model.

4.3 Currently the EDCM methodology often delivers lower distribution charges at the EHV/HV boundary than the CDCM. Therefore there have been instances where customers have moved metering in order to attract the lower EDCM charges. To ensure cost-reflectivity, it is important that the differences in charges across regimes are reflective of the different cost drivers, but presently, they are more directly related to the differences between charging methodologies. The most straightforward solution to meet this criteria would be to have the same methodologies for all customers' use of the same assets.

Harmonising Approaches at the Transmission/Distribution Boundary

4.4 Complete parity in charging arrangements across distribution and transmission may not be possible. Under EC Regulation 838/2010 Part B, the total TNUoS payable by chargeable generators must fall within the range of €0-2.50/MWh. On that basis, locationally granular and cost-reflective charges are calculated for generators but a negative residual charge is required currently to ensure that charges fall within the stipulated range. Where a generator connects to the distribution network, where there is no such restriction on the chargeable Use of System, a cost-reflective charge can be passed through in its entirety.

4.5 Any distribution-connected generator <100MW does not currently contribute to the costs of the transmission network but instead receives a credit via its supplier (the 'embedded export tariff', applicable at exports over triad). No transmission-connected generator currently contributes towards the costs of the distribution network.

4.6 For distribution-connected generators, it may be possible to levy transmission charges via either DNO or supplier, for instance, the ESO (Electricity System Operator) could determine a notional locational tariff based on generators' output (as they do not have contracted capacity on the transmission network) and pass this through to the DNO to include in DUoS, or to the Supplier, per the embedded export tariff. It may also be possible to extend the arrangements between ESO and DNOs such that the DNOs have assigned capacity at the GSP and the ESO creates a locational charge for that GSP – this charge could then be passed through DUoS (note, this could be technically possible without capacity arrangements between ESO and DNO).

4.7 The transmission locational charges are currently recovering a very small proportion of overall TNUoS and as such, the demand residual charge is currently around £2.7bn/year (there are regions where demand locational charges could be <£0). The CDCM models, however, are designed to deliver a positive charge to demand connectees. Whilst the residual charge is under review in the TCR, parity in arrangements may not be wholly possible in demand charging.

Alignment between Different Models

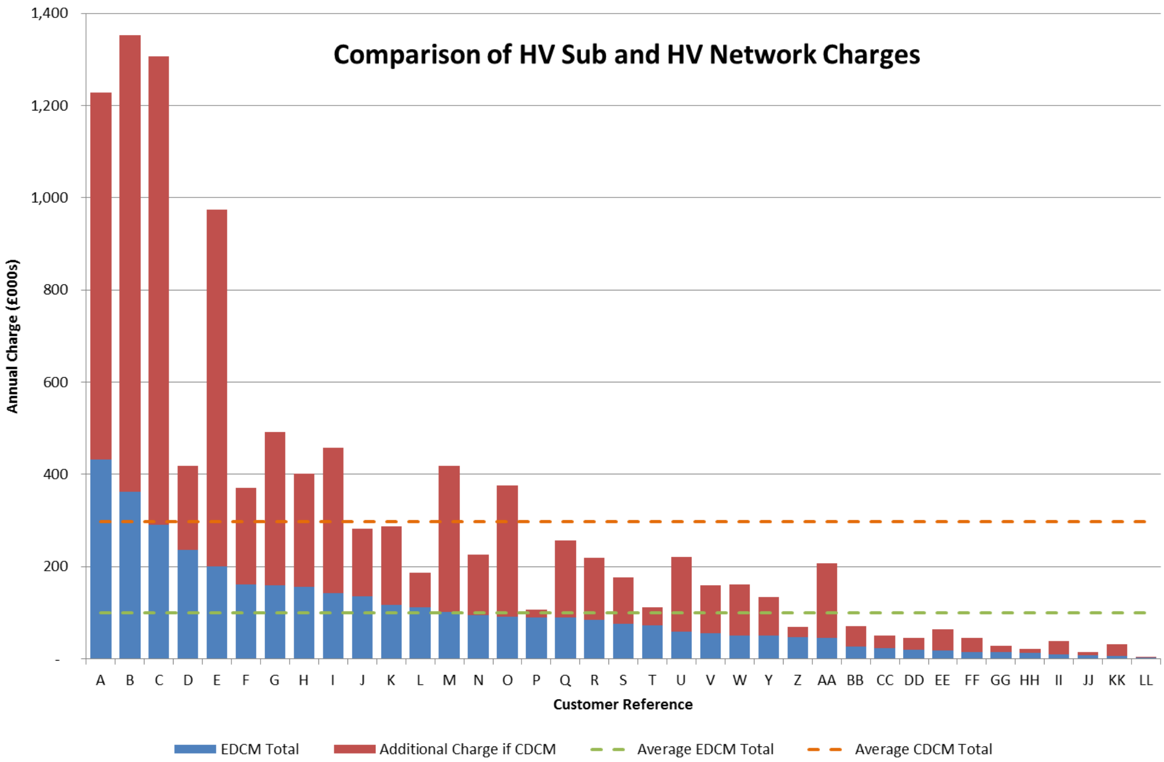
4.8 Different cost models can be used to represent costs at different voltage levels, but it is important that the cost drivers which underpin the different approaches align.

4.9 The magnitude of costs under a given cost driver is likely to differ between different voltage levels – for example fault repair costs are typically higher at lower voltages. But any approach which considers a given cost driver at one voltage level but not another will be distortionary and will ultimately skew cost recovery between voltage levels.

4.10 Hence in order to be cost-reflective, the approach taken forward must consider the same cost drivers at all voltage levels, whilst acknowledging the differing magnitude of each cost driver at each voltage level. The current boundary between EDCM and CDCM highlights the risks of including different methodologies for different customers' usage of the same network assets. Charges for customers connected to the HV side of a primary substation are calculated in accordance with the EDCM. Charges for customers connected to the HV network are calculated in accordance with the CDCM. The impact of a customer connected to direct to a primary substation compared to that of an equivalent customer connected to a short section of HV network (at the same primary substation) will be very similar. The only additional asset used by the HV network customer is a short HV circuit. The impact of the two customers on higher voltage assets could be assumed to be identical. But under the current arrangements the charging basis for use of higher voltage assets is fundamentally different.

4.11 Figure 6 shows the additional charge which would be incurred by each of the customers connected to the HV side of primary substation in the Yorkshire area if they were to instead connect to the HV network and their usage were to remain unchanged (i.e. the blue bar should be compared to the total stack). This highlights that if an EDCM customer connected to the HV side of a primary substation were to instead connect via a short section of HV network in the Yorkshire area, charges would increase by an average of around 200%, but could be as much as around 700% in the most extreme case.

Figure 6: Comparison of HV substation and HV network charges in Yorkshire



Section Conclusions

4.12 The current arrangements risk creating significant changes in the charges a customer faces due to regulatory boundaries rather than genuine cost differentials. Any attempt to improve locational granularity must be cognisant of this in order to develop proposals which have the potential to give cost-reflective signals for all of the voltage levels which a customer uses regardless of the voltage of connection. This is considered further in section 7.

5 Modelling Approaches

Section Summary

5.1 This section considers the two fundamental modelling approaches which are used for the current charging arrangements and gives a brief overview of the features of each approach. Consideration is also given to the data requirements of each approach, and the extent to which that data is available.

Two Approaches of the Status Quo

5.2 The current cost modelling approaches described in the previous section can be split into two broad groups:

- **Power flow models** are currently used to calculate forward-looking nodal prices (akin to the LRIC EDCM approach), zonal prices based on grouping adjacent nodes (akin to the transport model approach) or zonal prices based on grouping of nodes to derive inputs to the power flow modelling (akin to the FCP EDCM approach).
- **Asset models** are currently used to calculate average forward-looking charges for all CDCM customers in each DNO area.

5.3 Both power flow and asset models could be produced which represent different characteristics such as urban, rural, generator dominated, off-peak heating etc. which could assist in simplifying modelling approaches providing it is possible to identify an appropriate generic network type for each network area.

Benefits of Each Approach

5.4 Power flow modelling approaches are useful for identifying the costs of reinforcing the existing network. By analysing power flows on a detailed electrical model of the network, the model can identify which parts of the network will need reinforcing as load increases, and precisely which customers contribute to the projected need for reinforcement of each asset. The current power flow modelling approaches are exclusively focussed on network reinforcement as the sole driver of forward-looking network costs. The EDCM is reliant on NUFs and the generic asset model from the CDCM for the allocation of asset replacement costs. In the transmission charging approach replacement costs are considered either in locational or residual elements (owing to the cap on generation charges), but in either case are factored, by the relevant transmission operator, into the total maximum allowed revenue.

5.5 Asset modelling approaches identify the assets required to supply the existing customer base and are capable of considering a wider range of cost drivers such as future asset replacement and any cost which is likely to be proportional to asset value (e.g. operation and maintenance costs). More simplified power flow analysis can be used to assess the amount each user group makes use of particular assets. For example, the CDCM identifies the contribution to peak demand made by each user group as in many cases this is deemed to be the underlying driver of many costs.

Extent to Which Each Approach Can Be Forward-Looking

5.6 Both the power flow and asset based approaches can be forward-looking to different degrees. For example, they could both focus on determining:

a) the costs of recent reinforcement (power flow) or the costs of installing the existing network (asset based) using a current 'as built' representation of the network;
b) the costs of recent and planned reinforcement (power flow) or the costs of installing the existing network and any planned development (asset based) using an 'authorised' network

model which includes schemes that have been approved for construction but have not yet been completed; or

c) the costs of forecast future reinforcement (power flow) or the costs of installing new network when existing network assets are replaced (asset based) using a representation of the assets which would be installed under current practice should the network be replaced.

5.7 Option a) is effectively a backward looking approach, looking to recover the sunk costs associated with the existing network. Option b) incorporates some element of forward-looking costs by including planned schemes, but it is likely that any change to customer behaviour will not impact those schemes as the decision to implement them has already been taken. Only option c) is truly forward-looking, by seeking to quantify the likely future costs associated with incremental demand.

Potential Alternative to Power Flow Modelling

5.8 The current approaches for distribution power flow modelling use full Alternating Current (AC) power analysis software to derive the locational signals. In transmission a more simplified Direct Current (DC) model is implemented in Excel. The method in distribution leads to quite an opaque approach to pricing as it is difficult to share the detail with customers on how prices have been derived. It is doubtful whether such a complex and detailed approach to deriving charges is actually justified.

5.9 A possible alternative is to derive a price signal using data already produced by DNOs for other purposes. DNOs produce reinforcement load indices in their annual regulatory reporting packs. For each 132kV and 33kV substation and 33kV substation group this gives details of loading, capacity, limiting constraint and season of constraint. This information could be utilised as the basis to derive a more locational price signal in a more transparent way and remove the complexity from current approaches. How this could be achieved will be determined following the academic review into how network price signals should be derived from the available network data.

Section Conclusions

5.10 Both power flow and asset modelling may be useful for calculating locational charges, depending on the extent to which reinforcement costs and asset replacement costs are deemed to be locational. Power flow modelling approaches typically have more onerous input data and computational requirements. But there may be alternative approaches which have the potential to approximate power flow modelling outputs in a less resource-intensive manner.

6 Single Modelling Approach for all Distribution Voltages

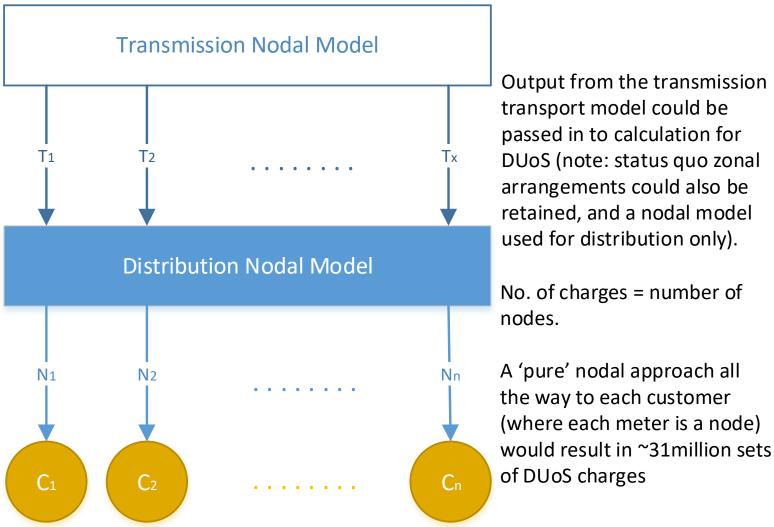
Section Summary

6.1 This section considers whether it would be possible to apply one of the existing approaches at all levels of the networks which would be feasible to implement whilst improving locational granularity. It considers an extension of nodal pricing from EHV down to lower voltage levels, followed by an extension of the use of representative network models up from HV and LV to include EHV.

Nodal Network Pricing for All Distribution Connected Customers

6.2 Figure 7 gives a diagrammatic representation of nodal pricing for all customers, with the nodal elements of transmission charges (which are aggregated up into zones under current arrangements) being added to distribution nodal charges to derive a single, nodal network charge for each customer. This could involve the charging signals for transmission circuits being passed to the DNO, and assigned to the relevant distribution network circuits in order to levy a single network charge. It should, however, be noted that the different components of the charges could be levied separately, provided that the assumptions and model inputs/outputs were consistent, resulting in the stacking of multiple charge components having the same effect.

Figure 7: Nodal charging for all network levels



6.3 Currently the EDCM extends as far as the lower voltage side of a primary substation. One possibility for future charging methodologies would be to extend this methodology further into the distribution network, subject to data availability and any proportionality assessment of the options.

6.4 Taken to the extreme, a 'pure' nodal approach would involve fully locational charges for each entry and exit point from the network. In effect every customer would be assigned an individual, site-specific tariff.

6.5 Extending the current LRIC/FCP approach used for EDCM from the HV side of the primary substation to include customers connected to the HV network and to the LV side of HV/LV substations would require significantly more resources, modelling tools and data requirements and may not be computationally possible using the current methodology.

Resources

6.6 For the current modelling DNOs typical spend several weeks collating and processing raw data to derive the inputs to the power flow model, uploading the data and checking/analysing the output. Without additional automation, a simple extrapolation would suggest that extending the power flow modelling would require 1,200 person days for each DNO.

Modelling tools

6.7 Currently different modelling tools are used for the HV network. If the HV/LVS models are incorporated into the existing modelling of EHV networks then computationally this may be quite difficult as the HV models would be “un-balanced” ones i.e. single phase networks exist as opposed to only balanced three phase at EHV. This would mean it will be unlikely that is would solve as one combined load flow model, but may need to be treated as a subset series of HV models.

6.8 The step change in model complexity would require completely new IT systems, software models, tools and business processes.

Data requirements

6.9 Using the SP Manweb area as an example, to move to HV/LV would require extending the model to cover 51,000 secondary transforms, where currently 849 primary transformers are modelled. This represents a 60x increase in model coverage.

6.10 Demand forecasts would need to be applied to a significant increase to the number of locations to be modelled. The forecasts would likely be very sensitive to changes in demand/generation and this would inherently introduce volatility into the charge signals. For a power flow based implementation of this approach, complete electrical and physical characteristics of all assets and their connectivity to each node would be needed (including nodes which are embedded within IDNO or licence exempt networks), with sufficient usage data at each node. For an asset based implementation, the complete costs associated with all assets would be needed, and their connectivity to each node.

6.11 From analysis of the DNO responses to the RFI, electrical and physical characteristics of all assets and their connectivity to each node is typically available down to primary substation level and to a certain extent at HV network level for some of the DNO areas. The evidence from the recent Ofgem RFI also indicates that there are possibilities for some of the companies to produce load flow output at the HV level, although this is not the case for all companies and so would be unlikely in the foreseeable future given the scale and complexity of those networks and would be exceedingly time consuming and costly to acquire, requiring system upgrades.

6.12 Sufficient customer information is likely to be collected by smart metering but it is unclear whether privacy restrictions will make this information unavailable to network operators. This will only become clear as network operators finalise and seek approval of their data privacy plans.

6.13 Costs of assets and their connectivity to each node is fully available down to primary substation level. It is not available for lower voltage and would be exceedingly time consuming and costly to acquire, requiring system upgrades.

Conclusion

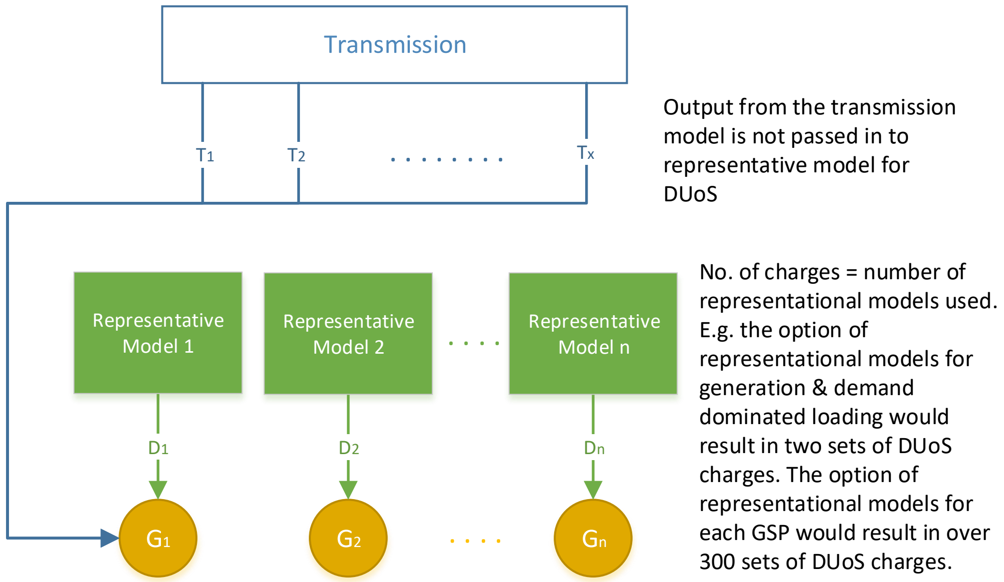
6.14 Deriving site-specific charges for ~31 million customers would be an unfeasibly time consuming and resource intensive exercise for no clear benefit. Though this may be theoretically the most cost-reflective option, the resource intensity would not be proportional to the benefits delivered because the differentiation in network costs at such a granular level are likely to be minimal (e.g. there would be no cost differentiation between different houses on the same housing estate).

6.15 In summary, 'pure' nodal pricing down to each individual connection (including HV and LV) is not feasible. Whilst it was not within the remit of this report to assess social acceptability, in this case, it also seems likely that a bespoke cost reflective network tariff for every user of the electricity network is unlikely to be socially acceptable.

Zonal representative network modelling for all customers

6.16 Figure 8 gives a diagrammatic representation of applying nodal transmission charges (as per the status quo) with the use of representative network models for all voltages of the distribution network.

Figure 8: Use of representative network models for all levels of the distribution network



6.17 The CDCM approach uses an average or representative network model for the addition of 500MW of load. It is this asset costing model that is used to derive the costs for customers. This approach could be extended and used to model different segmentations of customer be that by geography, network characteristics or any other suitable and justified segmentation

6.18 Under this option, a set of representative models would be determined. Those network models could either:

1. Represent the entire network, with each area having its own network model; or
2. Be a suite of archetypical network models based either on the characteristics of the customers connected to it or on the characteristics of the network itself (or both), with the archetypical model which most closely reflects the customer base or network characteristics then used for the calculation of charges for each area of the network.

6.19 The current 500MW model used in the CDCM would fall under case 1 above, albeit with each GSP group being a very large area with its own representative network model. The representative models could include the cost of incremental network usage (for a power flow approach) or the typical cost of assets to serve a given user (for an asset based approach).

6.20 This option could be used to increase granularity compared to the CDCM by creating more representative network models in a similar manner to the current approach. For example, an equivalent of the 500MW model could be created for each GSP, representing the customer base and network topology of that GSP specifically rather than of the GSP group as a whole.

6.21 More complex options could involve GSP group-wide representative models at the upper voltages, with a series of archetypical network models used for the calculation of charges at primary substations. This could be based on (for example) whether a primary is demand or generation dominated, with two archetypical network models used and charges calculated for each primary based on whether that primary is demand or generation dominated. This could increase locational granularity at the lower voltages.

6.22 But any such option using a representative model for the upper voltage levels would lessen the locational granularity of charges for EDCM customers, and so would likely present a retrograde step for locational granularity overall. Whilst this option may result in lesser locational granularity and so is not considered further in this report, there may be merit in considering this approach in the subsequent cost models work, as it could result in a more stable charge (than the current EDCM charges) based on a representative network approach for all distribution network users.

Conclusion

6.23 For customers connected at HV Sub and above (i.e. EDCM customers), this approach gives less locational granularity than the status quo and so is not considered further in this report. However, when combined with other options, it may increase locational granularity for HV and LV customers and may be an option worthy of consideration when factors such as stability of charges are considered in the subsequent cost modelling work.

<u>Section Conclusions</u>

6.24 An extension of the nodal approach for all customers is not feasible whilst an extension of the representative model approach is not compatible with the brief under which this report is being developed (being to increase locational granularity). Hence it is necessary to consider a combined approach using a hybrid of the two options.

7 Combining Different Modelling Approaches

Section summary

7.1 The previous section has concluded that using one or other of the approaches of the status quo is either not feasible or not desirable. This section considers how different modelling approaches could be combined to create a coherent approach for all voltage levels.

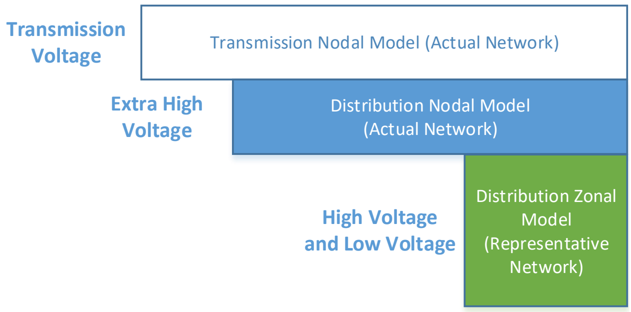
Modelling determined by the voltage of assets used by the customer

7.2 Under this approach, a 'boundary voltage' is set with:

- charges for use of assets at all voltages above that boundary voltage set using a nodal charging approach for all customers which use those assets; and
- charges for use of assets at all voltages below that boundary voltage set using an average approach for all customers which use those assets.

7.3 Figure 9 shows how models could be combined to ensure that users charges for assets at a given voltage level are calculated in the same way regardless of customers' voltage of connection.

Figure 9: Representation of modelling determined by the voltage of assets used by the customer



7.4 A key decision for the way in which options are combined to create hybrids is the 'boundary voltage'. Typically, the lower the voltage at which nodal prices are determined, the more locational the charges derived will be. However, this is reliant on accurate allocation of customer to assets at boundary voltage. The mapping of customers to electrical assets is sometimes inferred as the connectivity data is not always available. For example, a customer could be assumed to be connected to the nearest asset (e.g. a low voltage cable) whilst in practice it is connected electrically to a different transformer which is further away. The level of inference is reducing as DNOs improve their data. This improves the overall accuracy of determining which customers are connected to which asset though mapping of customers to assets is unlikely to be ever 100% accurate.

Availability of data for more nodal network charging

7.5 All DNOs have the capability to undertake detailed power system analysis down to the high voltage side (HV) of a primary substation (EHV/HV) as this analysis is required to implement both LRIC and FCP. DNOs responses to the RFI have been reviewed to determine whether it would be possible to extend this analysis, or potentially simplified analysis to produce nodal charging at lower voltage levels. The detailed responses are provided in Annex 3.

7.6 In summary, with regard to power system analysis at the HV level to support the extension of the current EDCM approaches, as stated previously in paragraph 6.14, extending the current LRIC/FCP approach used for EDCM from the HV side of the primary substation to include customers connected to the HV network and to the LV side of HV/LV substations would require significantly more resources, modelling tools and data requirements and may not be computationally possible using the current methodology. DNOs generally have discrete models at this level which are updated as required for analysis on a particular network to support a new connection request or to determine the approach to reinforcement. Some DNOs do have maintained models but they sometimes use different analysis software than used at EHV which does not have the automated scripting needed to undertake the EDCM approaches. At LV, modelling capabilities are even less with only discrete models available.

7.7 All DNOs have extensive monitoring down to primary substations, though in some cases the monitoring is current (amps) rather power (kW/ KVA). Some DNOs also monitor HV circuits at the primary substation in addition to the transformers. DNOs may also deploy more complex monitoring schemes in specific locations to support flexibility services or active network management schemes. These will be limited in deployment to support a particular solution and not appropriate for tariff setting which will require sufficient data from the whole network. At LV, there is generally less loading data available with a reliance on maximum demand data only. There are initiatives to increase the level of monitoring but the extent of the low voltage networks mean that if extensive monitoring were deployed it would take many years to roll out. What monitoring is required for charging purposes is dependent of the data needed to derive the charge, which will be considered in the academic and charge design work. If extensive time of use charging is to be introduced then sufficient monitoring at different times of the day will be required to support the charges calculation.

7.8 Whilst there are some initiatives by DNOs to extend power flow modelling and network monitoring, such capabilities will not be available across all DNOs in the near or medium terms and will not be available in the RIIO ED1 period or within the timescales of the SCR process. The current requirement for the EDCM approaches is to undertake full AC power system analysis and calculating incremental effects of changing load at large numbers of nodes. This is far more complex and onerous approach than is used to determine charges at transmission. The feasibility of determining more granular nodal charges will to a large extent be determined by the approach and data required to calculate the charge.

7.9 Under the current EDCM boundary, DNO produce around 4,300 site specific tariffs. If the boundary were lowered to customers connected to a lower voltage substation this would increase the number of site specific tariffs to around 38,500. The whole system impacts of DNOs publishing such a huge number of tariffs, including billing system and supplier validation of charges would also need to be considered.

Section Conclusions

7.10 In order to combine different modelling approaches without undermining cost-reflectivity at the boundary between those approaches, it is necessary to only use one modelling approach for assets at each voltage, with charges for assets at the voltage fed through to users connected downstream. In order to avoid decreasing locational granularity for users connected at EHV, nodal pricing for upper voltages should be maintained. As determined in section 6 the current EDCM modelling approach can only practically be deployed down to primary substation level.

7.11 So the remainder of this document assumes that nodal charging is used down to the primary substation and considers options which could be combined with that nodal modelling to give a coherent set of charges for all voltages for users connected at HV and LV.

8 Representative Network Models

Section summary

8.1 This section considers modelling approaches which could be used for the HV and LV networks, and how those approaches could be combined with the nodal approach at upper voltages.

High-level options for representative models

8.2 As covered in the previous sections, in order to maximise locational granularity, a nodal charging model should be used down to primary substation level. There are then four options for the way in which representative network models are defined:

- A separate network model created for each primary substation;
- A single network model created covering each licence area in its entirety;
- A group of network models created covering specific regions within each licence area; or
- A set of archetypical network models, which would be assigned to each primary.

8.3 Note that defining an area geographically or electrically may yield quite different results which may be difficult to explain to stakeholders. For example, in rural network areas the customers electrically connected to a given primary substation are also likely to be geographically distinct from those connected to another primary substation and therefore geographical and electrical groupings are likely be closely aligned. However, there are also many circumstances, particularly in urban areas where the electrical networks are likely to 'overlap', meaning that customers identified as geographically similar (e.g. buildings on the same street) may in fact be connected to different sections of the electrical network. Network configurations can also change which could alter customers' electrical connectivity despite the customer remaining in the same geographic location.

Separate model for each primary

8.4 Under this option, a network model would be created representing the assets serving a typical customer connected to each primary. It would entail the creation of *ca.* 5,500 representative network models across GB. The data needed to facilitate this option would be largely dependent on the nodal modelling approach used for higher voltages.

8.5 Under current arrangements, DNOs maintain a representative network model per licensee. In order to properly reflect the differences between each primary, detailed information will be needed on the mix of assets and customers connected to each of the *ca.* 5,500 primaries across GB. But despite assessing each individually, it is likely that many primaries will have similar mixes of assets and customers, so this is very unlikely to be a proportionate approach to creating locational charges when an approach using archetype network models will deliver a similar outcome for far less computational resource.

A single network model for each licensee

8.6 This would entail maintaining a network model akin to the existing 500MW model representing the HV and LV networks in that licence area. The resulting charges would still be more locationally granular than the status quo because the nodal prices for higher voltage network levels would still be used, but there would be limited locational granularity at HV and LV.

8.7 The improvements in locational granularity for this approach are derived only from the modelling carried out at higher voltage levels. The following options have the potential to deliver much greater locational granularity, and so this option will not be considered further at this stage.

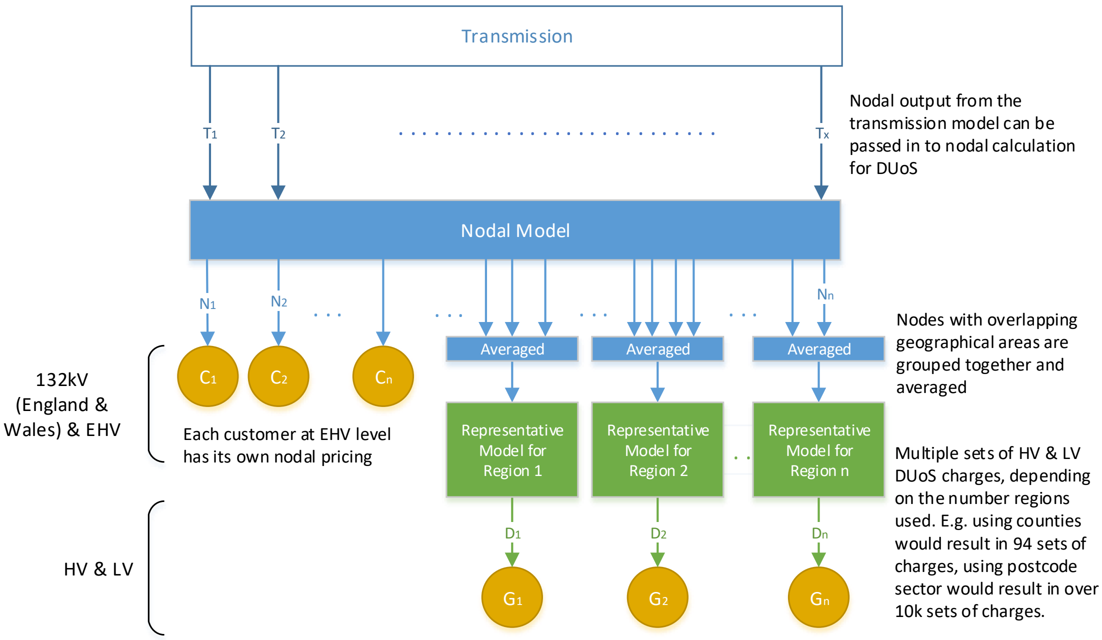
Regional network models

8.8 This would require each DNO to geographically segment its licence area. A network model would then be created for each geographic area, representing the network topology and customer base within that region. Under this option, it may also be sensible to consider averaging the nodal charges for nodes within a given geographic region, to create a single price applicable to customers in each region.

Representative network models used with regions defined by geographic factors

8.9 Figure 10 gives a diagrammatic representation of applying nodal charges at EHV and above, with the charges for HV and LV networks determined using representative network models applied to geographical regions.

Figure 10: Representative network models for geographic regions

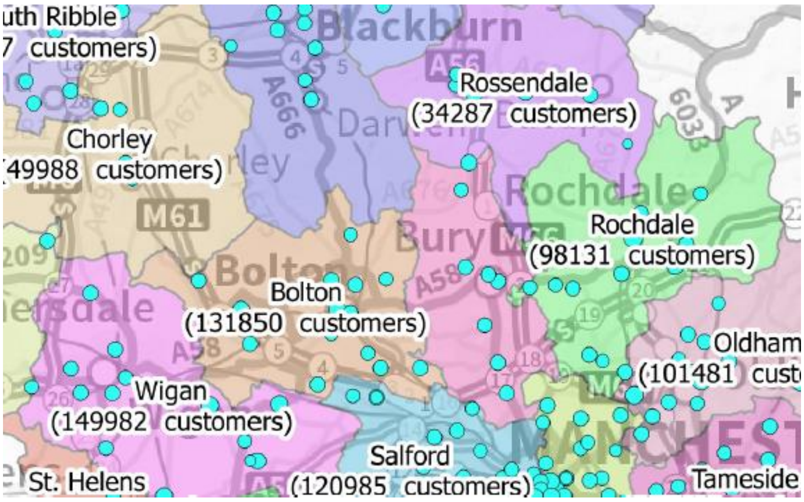


8.10 Under this option, the DNO's entire network area would be divided into regions based either on postcode, section of postcode (i.e. postcode area, postcode district or postcode sector), county , council area or ward, or based on some other means the DNO uses to segment its network (e.g. DNO operational zones). A representative model would be created for each region, based on the characteristics of the customer base and the network in that region.

8.11 In order for this option to be used, a mapping of customer to region would be required. Network operators hold address data (including postcode) for each connection to their networks, albeit not all connections to the electrical network have a postcode (e.g. unmetered supplies, pumping stations, traction supplies etc.) so a mechanism would be needed to assign a 'pseudo postcode' to those customers.

8.12 Such postcode data would make all options involving grouping by postcode straightforward. Similarly for council areas, it should be possible to map each postcode to a council area or ward as this data is freely available. An illustration of this approach is given below (Figure 11). In this particular example, the geographic area is defined by council area. A representative model for each area could then be determined using the mix of customers in the area, the loading and utilisation of the networks and the assets required to supply these customers. In the example, the primary substations supplying the area are also illustrated.

Figure 11: An example of a geographic network model



8.13 The level of granularity used is a key consideration – the practicality of implementing this option is improved by using larger areas, i.e. by using fewer elements of the postcode. Table 4 shows the count of regions which would be created by using different granularities of postcode[5].

Table 4: Count of distinct areas by postcode section

Postcode Section	Example (based on SW1 1AA)	UK Count of Distinct Areas
Area	SW	124
District	SW1	2,980
Sector	SW1 1	11,198
Postcode	SW1 1AA	1,756,807

8.14 Some postcode areas cross DNO network boundaries, so common charges are unlikely to be applied across those postcode areas. It should also be noted that the more granular the area the less accurate the information will be. At the boundaries between geographic areas, customers in one area may in fact be supplied by assets in another area. These boundary effects have a larger impact on the overall accuracy of the approach as the areas reduce in size.

[5] Source: https://www.bph-postcodes.co.uk/guidetopc.cgi

Practical and Proportionate Assessment

8.15 The practical and proportionate assessment criteria used to evaluate particular options are described in paragraph 2.10. For criteria number 1, data availability, this is assessed as Amber. The assessment depends on the degree of granularity required, but data sets are available to assign customers and assets to particular regions. It is unlikely that DNOs could assign particular costs to a region but it would be possible to assign typical costs per asset type.

8.16 For criteria number 2, data processing, this is also assessed as Amber. The assessment depends on the degree of granularity required, but the approach should not be dissimilar to producing the CDCM models, though with a large number of models the likelihood of human error in populating each model increases.

8.17 For criteria number 3, data accuracy, this is also assessed as amber, though the more granular the approach the more estimates and assumptions would be required which could make the assessment red.

Conclusion

8.18 This may be a feasible option depending on how granular the zones are defined.

8.19 There are other considerations with the use of postcodes which would make this a less feasible option. Firstly, there may only be a partial postcode for a property, for example only the postcode (first 4 digits). Secondly, a property could have an incorrect postcode assigned to it and this may not identifiable. Continual cleansing of postcode to MPAN (Meter Point Administration Number) data would be required. Thirdly, unmetered supplies are billed on aggregates which will cover for example a whole local council which would include many postcodes. This could become a more significant issue as electric vehicle charging points are allowed against lamp posts and so the volume of electricity may rise considerably.

Archetypical network models

8.20 Under this option, each DNO would create a series of hypothetical, archetypical network models, which varied depending on either network (e.g. demand/generation dominant or level of loading) or customer (e.g. rural/urban or residential/commercial) characteristics. The DNO would then consider the network and/or customer base at each (e.g.) primary and determine which of the archetypical network models most closely resembled the network under that primary.

Archetypical representative network models used varying by level of loading

8.21 A measure of the level of loading at each substation would be used to determine which representative network applies to customers connected at that substation. At its most simplistic, this would use archetypical network models for demand or generation dominated networks, whilst a more nuanced version would use the level of loading to give a non-binary allocation of zones to representative models based on whether (for example) peak demand on the network is 0-50%, 50-80% or 80-100% of the network’s capability. These approaches are represented by Figure 12 and Figure 13.

Figure 12: Representative network models for generation and demand dominated primaries

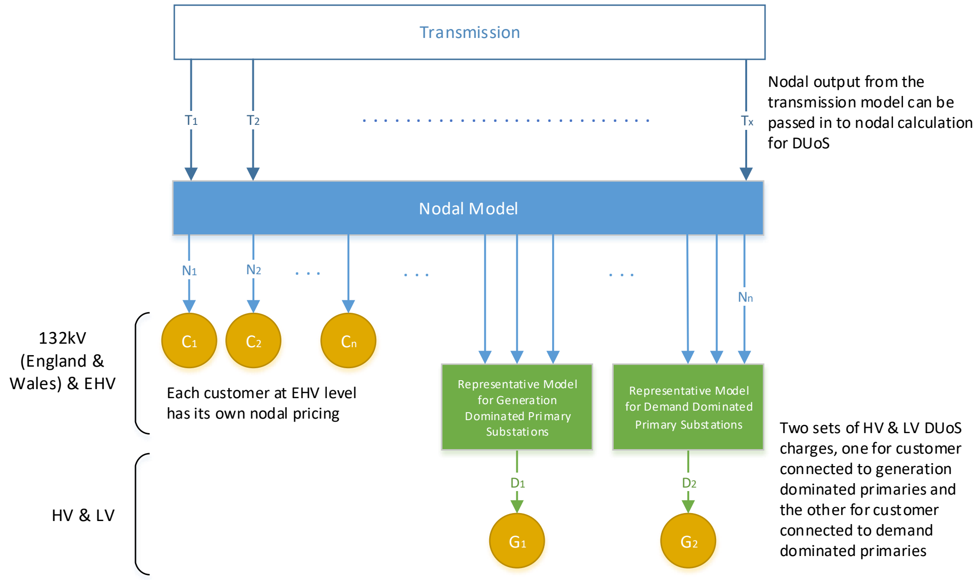
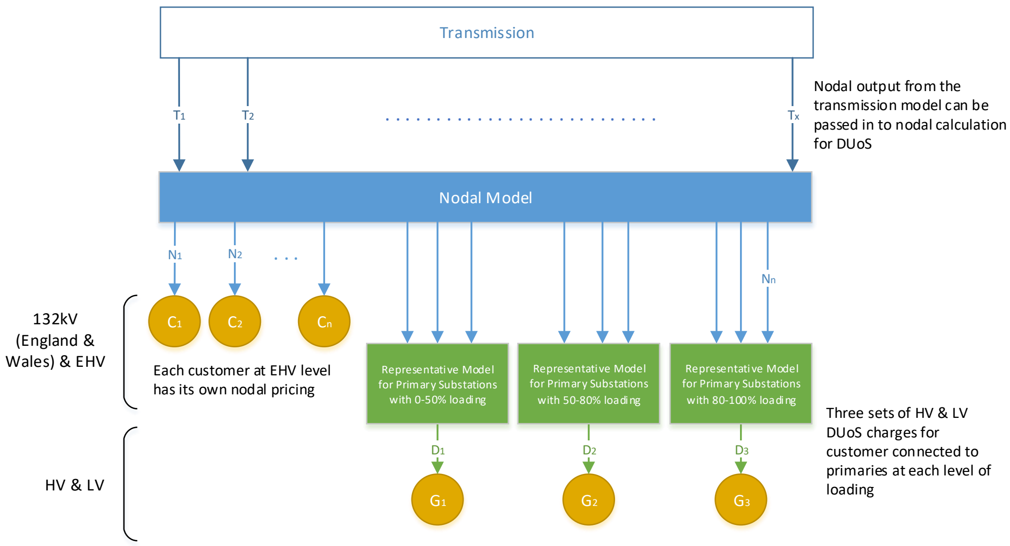


Figure 13: Representative network models determined by level of loading



8.22 This approach may not ultimately rely on fundamentally different network models, but may simply be achieved by applying them differently. A crude example would be to determine a network model assuming demand dominance and simply reverse the polarity of the prices determined when considering generation dominated network.

8.23 Data required to define models for this option would be similar to those for the 500MW model, albeit potentially needing several of those models. This data would be as per existing requirements so is readily available.

8.24 For the allocation of network models to customers, network monitoring data needed would depend on the mechanism by which demand/generation dominance is determined. If based only on peak flow, only maximum demand data is needed to determine whether a given network location is demand or generation dominated, but if based on (e.g.) total net volume, half-hourly monitoring will be required. If only maximum demand reads are needed, these are typically available down to distribution substation level (excluding pole mounted transformers). Half-hourly monitoring is available down to primary substation level, with all DNOs monitoring at least down to the incoming EHV feeders to each primary substation. Some DNOs also monitor the outgoing HV feeders from primary substations. The quality of the measured data is not to metering accuracy in all cases. A number of DNOs have initiatives to extend the monitoring of the networks but these are typically closely targeted at substations which are already close to reinforcement. Large scale coverage is not currently planned.

8.25 A connectivity model showing the zone within which each customer is connected would be needed (e.g. if zones are by primary, a mapping showing the primary to which each customer is connected). This data is available down to the HV networks. Connectivity models to the lower voltage networks are being developed by DNOs but these is a range of capabilities and progress.

Practical and Proportionate assessment

8.26 The assessment against the 'data availability' criteria is green. Assuming the level of loading is determined based on usage at the primary substation, similar data will be required to that used for the EDCM power flow modelling under current arrangements and so is readily available. However, if the level of loading were required further down the network, this would move to amber or red depending on the voltage at which data is required.

8.27 The assessment of data processing is amber. The assessment depends on the degree of granularity required, but the approach should not be dissimilar to producing the CDCM models, though with a large number of models the likelihood of human error in populating each model increases.

8.28 The assessment of data accuracy is also amber. Significant assumptions will be required when determining the level of loading at a given primary. In order to establish a consistent approach, a prescriptive method will be required to determine whether a primary is (for example) demand or generation dominant. But a prescriptive approach will not cover every scenario, and in fact many primaries will be demand dominated at certain times and generation dominant at others, so any binary assignment will inevitably result in a level of inaccuracy.

8.29 More specific assessment will be required when particular archetypes are identified to represent particular cost drivers.

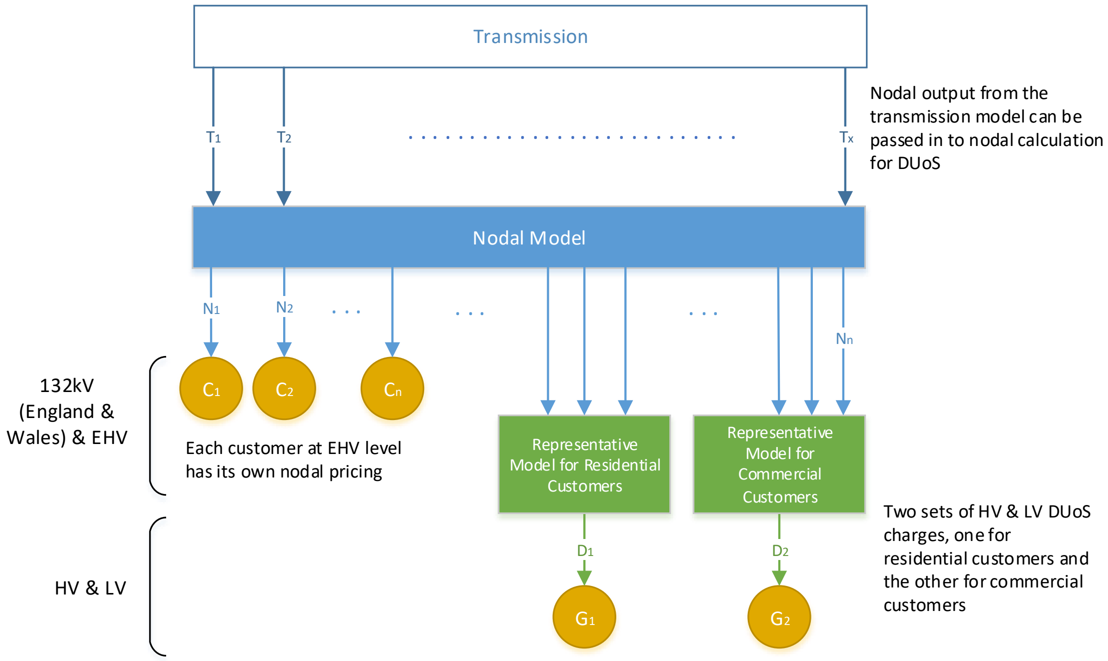
Conclusion

8.30 This option is likely to be feasible but is dependent on key design choices which will determine the number of network models which are required and the way in which a network model is allocated to each customer or zone.

<u>Archetypical representative network models used varying by customer characteristics</u>

8.31 Under this approach, a suite of archetypical network models would be created, which would be representative of the typical network designed to serve customers of a given type (e.g. residential, commercial or industrial). Users would be categorised based on their end-use, and the most appropriate network model used based on the dominant category of customer connected. Figure 14 shows the use of representative models based on customer characteristics.

Figure 14: Representative network models determined by customer characteristics



8.32 A more nuanced version of this approach could be to use differing proportions of the archetypical networks depending on the customer base (e.g. a primary with 40% commercial and 60% domestic load could have charges derived using a 40% scalar of a 'commercial' archetype network model and a 60% scalar of a 'domestic' archetype network model).

8.33 This option requires knowledge of end-use for all users. Network operators hold registration data for each connection point. This is a combination of data which the supplier is responsible for assigning (at the time of connection or following any subsequent change) and data which the distributor is responsible for assigning. For each MPAN, the following data is held:

- **Profile class (PC)**. The PC is between 00 and 08 and is used to assign profile coefficients to non-half-hourly settled customers, with those coefficients used to estimate half-hourly usage data for each customer from periodic (e.g. monthly) meter reads. The supplier is responsible for assigning the appropriate PC. Note: BSC change P272 'Mandatory Half-Hourly Settlement for Profile Class 5-8' has results in PCs 5-8 being phased out. The PCs used are as follows:
    - 00 – half-hourly settled customers
    - 01 – Domestic Unrestricted customers
    - 02 – Domestic Economy 7 customers
    - 03 – Non-Domestic Unrestricted customers
    - 04 – Non-Domestic Economy 7 customers
    - 05 – Non-Domestic Maximum Demand customers with a Peak Load Factor of less than 20%
    - 06 – Non-Domestic Maximum Demand customers with a Peak Load Factor between 20% and 30%
    - 07 – Non-Domestic Maximum Demand customers with a Peak Load Factor between 30% and 40%
    - 08 – Non-Domestic Maximum Demand customers with a Peak Load Factor over 40%.
- **Standard Settlement Configuration (SSC)**. The SSC is a four digit identifier which defines how a non-half-hourly meter is configured for Settlement. It defines how many time periods are applicable for a given meter and the times consumption is recorded in each time period. For the majority of non-half-hourly settled customers, the 'unrestricted' SSC is used, reflecting that only a single unit rate applies. However, it does enable the

identification of 'Economy 7' type customers, where multiple unit rates apply as defined by the SSC. SSCs are not applicable to half-hourly settled customers where consumption in each time band can be calculated directly from the actual half-hourly metering data. The supplier is responsible for assigning the appropriate SSC.

- **Measurement Class (MC)**. The MC is a letter A-G and categorises each metering system. The supplier is responsible for assigning the appropriate MC. The MCs in use are:
    - A – Non-half-hourly metered
    - B – Non-half-hourly unmetered
    - C – Half-hourly metered in 100kW premises
    - D – Half-hourly unmetered
    - E – Half-hourly Metering Equipment at below 100kW Premises with current transformer
    - F – Half-hourly Metering Equipment at below 100kW Premises with current transformer or whole current, and at Domestic Premises
    - G – Half-hourly Metering Equipment at below 100kW Premises with whole current and not at Domestic Premises
- **Line loss factor class (LLFC).** The LLFC is a three digit alpha-numeric identifier which determines the loss factors which are applied to an end users metering data in Settlement to determine their likely contribution to their supplier's total volumes at GSP level. It is also used to assign the appropriate DUoS tariff. Distributors are responsible for determining the appropriate LLFC. In many instances the combination of PC and SSC assigned by the supplier uniquely identify the appropriate LLFC, although there are some instances (e.g. half-hourly Settled CT metered customers) where multiple voltages of connection could apply to the same combination of PC and SSC so distributors are required to determine which LLFC should apply based on the voltage of connection.

8.34 Many of these registration details can be used to determine the customer type (domestic or non-domestic). For example, for non-half-hourly settled customers the PC can be used to determine whether the customer is domestic (PC 1-2) or non-domestic (PC 3-8), whilst for half-hourly settled customers the MC can be used to determine whether the customer is domestic (MC F) or non-domestic (MC C, E or G). However, drawing a clear distinction between commercial and industrial could be challenging but may be achieved through a defined rule-set using registration data – for example commercial could be defined as non-domestic customers with whole current metering, being those in MC A on PC 3-8 and those in MC G.

8.35 The boundary between commercial and industrial (or residential and commercial) is not necessarily clear cut, for example sites could mix industrial and commercial loads behind the same meter making the allocation of network models challenging.

Practical and Proportionate Assessment

8.36 Data availability has been assessed as Green (see paragraph 2.10 for RAG definitions). The approach is essentially producing multiple CDCM type models for different types of customer that may require different mixes of assets to service their requirements.

8.37 Data processing has also been assessed as Green. The assessment depends on the degree of granularity required, but the approach should not be dissimilar to producing the CDCM models, though with a large number of models the likelihood of human error in populating each model increases.

8.38 Data accuracy has been assessed as Amber, though the more granular the approach the more estimates and assumptions would be required which could make the assessment Red.

Conclusion

8.39 Assuming a sound mechanism for differentiating between commercial and industrial customers can be defined, this option is likely to be feasible. Alternatively, this could be simplified to only distinguish between domestic and non-domestic users.

Section Summary

8.40 Table 5 below shows the options which have been explored in full. All assumed nodal down to EHV and representative below.

Table 5: Summary of Practical and Proportionate Assessment

Option	Data Availability	Data Processing	Data Accuracy
Geographic Regional	**A**	**A**	**A**
Archetypical – level of loading	**G**	**A**	**A**
Archetypical – customer characteristic	**G**	**G**	**A**

9 Conclusion and Next Steps

9.1 The analysis set out in the previous chapters illustrates that it would be feasible to introduce greater granularity into use of system charges and increase consistency between charges set at transmission level, distribution EHV and distribution non-EHV to remove boundary issues which artificially encourage customers to connect at different voltage levels. In order to progress this work further, additional assessment is required on the options for the boundaries between the various approaches that have been identified.

Option to Extend Transport Model Principles Down to 132/33kV in England and Wales

9.2 Transmission charges are calculated by National Grid Electricity System Operator (NGESO) using their transport model. This model calculates charges down to the 132kV system in England and Wales but down to 33kV in Scotland as the 132kV network in Scotland is classed as transmission. As illustrated in **Error! Reference source not found.**, these charges are l evied directly on suppliers to pass through to the relevant customer. This has raised a number of concerns that 132kV connected customers are charged differently in Scotland than they are in England & Wales.

9.3 A potential solution would be for the NGESO to calculate the forward-looking charge for all the 132kV networks using their transport model. Under this approach the England and Wales DNOs would provide the required data to the NGESO (a composite network topology model of the entire 132kV network from the GSP down to the HV boundary) to enable it to calculate the forward-looking charges associated with each 132kV/EHV substation, as they currently calculate in Scotland. The England & Wales DNOs would then incorporate these forward-looking charges into their charging methodology. The transport model works on a scenario basis to optimise for the whole network, therefore it is necessary to have a single whole network model to conduct this assessment (different parts of the network cannot easily be assessed in isolation since, if part of the 132kV network was missing from the model, it would alter the prices for all other network users).

9.4 A further option to provide potentially greater locational granularity would be for the transmission transport charge at each GSP to be levied on the DNOs, with these charges then incorporated into DNO's charges. This would require changes to the regulatory arrangements to allow DNOs to pass these charges through and also to ensure that the NGESO is not exposed to significant cash-flow risk. The potential advantage of this is that costs at the transmission level which are currently averaged across the DNO region, particularly for demand, could also be made more granular and be combined with more granular distribution charges. This would provide more coherence to the requirement for more granular charges at distribution level, which different charges being considered for particular nodes or discrete areas with the practice at transmission where costs are averaged over large numbers of nodes and wide areas.

Options for Boundary between Nodal and Representative Models

9.5 The current boundary for nodal charging is the low voltage side of primary substations or customers connected to the EHV or 132kV networks. There are approximately 4,300 customers numbers in GB under the current EDCM methodology plus a further 34,500 customers connecting to the HV networks and substations. Some DNOs have indicated that the nodal approach could be extended to nodes on the HV networks. This would increase the number of nodes to around 600,000 including nodes where there isn't a directly connected customer. Therefore, in addition to the lack of data and capability of the DNOs in undertaking this analysis in the short/ medium term, it is clearly not practicable to deal with such a large number of nodes. This suggests that it is not feasible to move the boundary between the nodal and representative models beyond the current HV substation boundary. It would, however, be feasible to use the charges derived from the nodal models for the substations to introduce greater locational granularity for customers connected to the HV networks and below.

Annex 1: Glossary

The following terms are used throughout this document:

- ‘Branch’ – a section of electrical network connecting two nodes.
- ‘Node’ – a single point on the network. Examples include:
    - a given customer’s point of connection;
    - a given customer’s point of common coupling (the point at which sole use assets meet the shared use network); or
    - the point at which incoming (high voltage) or outgoing (low voltage) feeders connect to a substation.
- ‘Nodal charging’ – a price set for each individual node.
    - The LRIC approach used for some distribution networks uses the cost of incremental demand at each customer’s point of common coupling to derive charges for use of the shared network for that customer – this is a nodal charging approach.
- ‘Region’ – a geographically defined area.
- ‘Regional charging’ – charges set for customers within areas defined by geographic characteristics.
    - The key differentiation between ‘zonal’ and ‘regional’ is that zones are defined by characteristics of the electrical network whilst regions are defined by geographical characteristics.
    - This differentiation is not always so clear cut – for example, a given DNO’s distribution services area is defined geographically but could also be defined zonally as a group of GSPs.
- ‘Zone’ – a group of nodes.
    - Zones can be defined in many different ways.
- ‘Zonal charging’ – a price set for a group of nodes.
    - The FCP approach used for some distribution networks uses the cost of incremental demand for a group of nodes to derive charges for use of the shared network for all customers connected to those nodes – this is a zonal charging approach.
    - The ICRP approach used for the transmission network calculates a charge per node, and then groups nodes which are both electrically adjacent with and have similar charges into zones, with the nodal charges averaged across each zone to determine charges for customers connected in that zone.

Annex 2: Previous work undertaken on locational charging

Options for locational charging have previously been considered to some degree in at least four forums, namely:

- the 'EDCM review' which concluded in December 2015;
- stage one of the 'CDCM review' which concluded in October 2016;
- stage two of the 'CDCM review' which concluded in June 2017; and
- the Access and Forward-Looking Charges Task Forces which concluded in May 2018.

EDCM Review Group Report – December 2015
The two main proposals of the EDCM review group in this area were:

- removing and replacing 'Charge 1' (which sets charges based on future reinforcements) with an alternative method of calculating a unit charge; and
- use of a single EDCM based on Network Use Factors for setting locational charges.

Both of these options would reduce the locational granularity of EDCM charges, therefore may not be considered further as they are not compatible with the brief under which this report is being developed.

CDCM Review Stage One Report – October 2016
Alternative approaches to the 500MW model were considered, including:

- use of generic 500MW models (which could include both demand and generation) using benchmark / Ofgem allowed costs and RRP (Regulatory Reporting Pack) data for asset volumes making it DNO specific;
- full network models using RRP data;
- new 500MW model including all relevant costs;
- notional efficient network similar to the 500MW model but adjusted to account for generation and future technologies;
- derivation of a new 500MW model which would determine the minimum level of assets to meet green and/or amber time band levels of demand which can then be used to determine minimum charges (unit rates and/or capacity) and another model for peak that includes the assets necessary to meet peak demand.

Despite the drive for increased locational granularity, it is likely that representative network models will be required for charging for at least some voltages of the networks. The improvements to representative models considered by the CDCM review may be of interest in the context of this report.

CDCM Review Stage Two Report – June 2017
Initial views were that two contrasting costing model options should be developed further:

- An improved 500MW model which seeks to address some of the concerns with the existing models around inclusion of replacement costs, commonality, transparency, and the exclusion of DG. This option maintains the forward-looking approach.
- Full network costing model which would determine the modern equivalent asset value of the full network using the 'asset register' submitted in regulatory reports.

The former of these focusses on improvements to the representative network models used and so may be of interest in the context of this report. The latter is effectively non-locational and so not compatible with the brief under which this report is being developed.

Access and Forward-Looking Charges Task Force Final Report
Three options were considered under the building blocks for generating locational charges:

- **a ‘500MW’ model** (as used at LV and HV currently) or a **probabilistic approach**, which assigns the costs of reinforcement to a user (or group of users) in proportion to the probability that an increment of usage by that user will trigger reinforcement on the assets to which that user is connected, i.e. a ‘cost allocation’ model;
- **DC load flow investment cost related pricing (DCLF ICRP)**, which calculates the incremental cost of additional demand and/or generation at a nodal level based on peak system load being met by either intermittent or conventional generation (i.e. an ‘incremental’ model); and
- **forward cost pricing** which calculates the expected cost of reinforcement for a given network group (i.e. a group of nodes), with charges calculated based on recovering that cost over the calculated length of time until that reinforcement is expected to be necessary, i.e. a ‘contingency’ model.

These options will be considered further, albeit at a high level as, for example, the ICRP and FCP are variations on the same theme as they both provide high locational granularity. This report aims to identify the level of locational granularity which is both feasible and cost-reflective, without giving consideration to detailed design considerations such as the specific choice of nodal network modelling approach to be used.

Annex 3: Relevant extracts from Ofgem's January 2019 request for information

Electricity Northwest Ltd

ENWL maintain power system models as an accurate representation of our present whole EHV (132kV and 33kV) network and also their whole HV (11kV and 6.6kV) network. Electrical connectivity, equipment parameters including circuit impedances, loads and embedded generators are all represented consistently across these networks.

The models are updated on a regular basis as new equipment is connected to and disconnected from the network. Incorporated data is of a good quality when considering the historic development of the network and studies using these models are judged to give sufficiently accurate results to inform our network development plans. Some assumptions have to made where accurate data is not available; for example in the absence of continuous measurements of the load on individual distribution transformers (HV/LV), the measured load is allocated on each feeder to the distribution substations connected to that feeder.

Comprehensive data is available for their LV networks, but an electrical model of the whole connected LV network is not maintained. Such LV network models have been developed for innovation projects but these are limited to small portions of the LV network.

Whilst the modelling software is available to determine the EDCM charges for primary substations and above, they are currently not equipped to undertake the HV and LV network studies that would be required to produce pricing for HV and LV customers. The present software used for HV network models doesn't currently have the necessary automation needed and they are currently unable to conduct automated simulations of LV network behaviour. This may be much easier in the future as ENWL are investing in a new Network Management System which will improve how will provide opportunities for simulating network behaviour at all voltages (EHV, HV and LV). In conjunction with this a comprehensive data cleanse is being undertaken to produce a consistent accurate data set and new network models.

In terms of load data, all 132kV and 33kV substations have SCADA installed, which allows near real time monitoring of voltage, current, real and reactive power. 6.6kV and 11kV primary substations also have SCADA fitted on incoming transformer circuit breakers and feeder circuit breakers providing the same capability. This information is stored in the form of half hour averages, with data retained for a period of seven years. Most ground mounted distribution substations have maximum demand indicators. A very small but increasing number of ground mounted distribution fuses have a smart fuse fitted. These intelligent and controllable devices provide remote indication of feeder current and voltage. New 6.6kV and 11kV generation connections will be fitted with four quadrant monitoring.

Northern Powergrid

As for all DNOs, NPG have the capability to undertake detailed analysis to EHV and a full connectivity model at EHV maintained.

Current (amps) data available on outgoing HV feeders from primaries but voltage reference required to derive kW data. kW data is available at primary transformer level. Half-hourly monitoring is being deployed on select distribution substations, but is not expected to be widespread in the foreseeable future.

Regarding the representation of system data in models for design purposes, NPG currently only use the substation maximum demand information and engineers will look at HV feeder load profiles in the PI historian to determine peak feeder loadings for the feeders. The system models do not process half-hourly data.

NPG do not comment on the availability of data to produce comprehensive power flow modelling below EHV but comment that it would result a large increase in the resources required to carry out intensive power flow modelling when calculating tariffs.

For all half-hourly site-specific settled customers connected at EHV, HV and LV, half-hourly information is stored in a data historian which has an asset framework model that allows them to assign customers to the primary substation that feeds the network to which they are connected. NPG use this information in particular to summate the generation export profiles to enable them to calculate the gross maximum demands at the primary substations. NPG have plans to map all half-hourly customers to the primary substation. This information is currently 93% complete.

Scottish Power Energy Networks

A network connectivity model is available at 132kV and EHV. Network models at HV and LV are built on an ad hoc basis, based on specific connection enquiries and reinforcement requirements and as such there is no managed power flow connectivity model at HV and LV.

All Grid (132/33kV) and Primary (33/11kV) substations have conventional power flow monitoring (for half-hourly amps, volts, real power and reactive power). The accuracy and quality of this data is good and is fully aligned with the network connectivity model.

In addition, enhanced secondary substation monitoring (ESSM) provides the most locationally granular network data. ESSM measures each phase of each LV feeder emanating from a secondary substation (11kV/LV). This type of monitoring is new for ED1, as such there is very little coverage at present, but by the end of ED1. ESSM will be installed in 10-12% of secondary substations with a capacity greater than 200kVA. These installations will be targeted towards substations most likely to become overloaded. The accuracy of the secondary substation current and voltage measurement is typically 1-2%.

Scottish and Southern Electricity Networks

SSEN provide no indication of their power flow modelling capabilities in the request for information, however full connectivity and power flow modelling is assumed to at least EHV to enable EDCM charging.

In terms of data, a very high percentage of their 132kV down to 6.6kV circuit breakers have amps measured and recorded in a real-time database. Where there is no direct measurement other monitoring is available which would allow the data to be inferred. The current standard for circuit breakers requires more data e.g. Amps, Volts, MW and MVar so more data will become available as switchgear is changed.

On their HV network there is monitoring but this is generally refreshed far less frequently (sometimes only twice a day). Newer devices are being introduced which will produce more real time data but this is still a very low amount when compared to the volume of assets and HV circuits. There is no real monitoring of LV. Many of the measurement devices are not metering class so the quality of the data could be improved by more accurate measurement.

In the SHEPD area, network monitoring has reduced granularity/density in more rural areas.

UK Power Networks

For EHV and 132kV networks UKPN have full three phase load flow modelling tool covering all three of their licence areas which is linked to network monitoring data automatically. They have a modelling tool which can be used to study load flows for sections of network in isolation for HV and LV, however in LPN this requires manual updating of network monitoring data. UKPN are in the process of upgrading to a single model for all three licence areas that is capable for three phase load flow modelling for the HV and LV networks.

UKPN comprehensively monitors its EHV and HV networks across its three licence areas. Some of these are legacy monitoring devices and are not capable of providing information on dynamic and multi-directional power flows.

A new standard has been developed which looks to provide a standard approach to the design of these systems at each of the voltage levels. For example at both EHV and HV networks this would require visibility of Volts, Amps, Active Power, Reactive Power, Power Factor, Power Quality (Harmonics), Frequency and Fault Level. Currently, however, in most cases only have Volts, Amps, Active Power and Reactive Power are currently available.

Western Power Distribution

In addition to connectivity and power flow modelling at EHV to enable EDCM charging, WPD indicate that more granular HV prices could be determined by extending load flow modelling further down the network to include HV network customers. They state that this would be computationally onerous but possible but with practical considerations around it – data quantities, validation and checking. Their view is that large parts of the process could be automated.

A number of parameters are monitored across the network at different voltage levels. They have monitoring across the EHV (132kV, 66kV, and 33kV) networks, down to the outgoing 11kV feeder breakers at the Primary Substation 11kV bars. They do not have any visibility out in to the 11kV networks (other than some remote automation devices) for network configuration.

Product description on proposal to establish a Delivery Group sub-group focused on:

Locational Granularity of DUoS Forward-Looking Charges

1. Context and objectives

1.1. This advice is being sought in the context of Ofgem's Significant Code Review (SCR) into electricity network access rights and forward-looking charges, which was launched in December 2018.

1.2. While the SCR is Ofgem-led, the SCR will also involve significant industry input. A Delivery Group of network stakeholders has been established. We propose to establish a sub-group under this Delivery Group focused on the Locational Granularity of DUoS Forward-Looking Charges to deliver this request. The sub-group would be comprised of a selection of network stakeholders and Patrick Cassels from Ofgem's Network Access and Forward-Looking Charges team.

1.3. This advice is a foundational piece of analysis that will be important in helping to shape the listing and analysis of charging and access rights options under the SCR. Given the foundational nature, it is important that the requested timeframes are achieved. Accordingly, we are keen to shape the scope of this task so it is manageable within the timeframes.

1.4. It is commonly understood that a goal of network charging and access reform is to make charges more "cost reflective". It is also commonly understood that a more locationally granular approach to network charges can improve the cost reflectivity, as network charges will be more bespoke to individual network users, and the impacts of their behaviour on network costs.

1.5. Additional locational granularity may be desirable to achieve improved cost-reflectivity, however we recognise that the options may be restricted by practicalities of the network and user information that is readily available, or could be acquired. This is particularly true for users connected to the high voltage and low voltage networks, where currently granular data and models may not exist or be readily available. The sub-group has been formed to assess the degree to which more locationally granular approaches can be applied in future, including the extent to which the more granular approaches presently applied at extra-high voltage could be consolidated and extended to lower voltages.

1.6. Initially, this sub-group should consider the options available to increase the locational granularity of the DUoS regime. The sub-group should list and assess the practicality of options to increase granularity. These range from:

- Charges based on an accurate nodal model of the networks – considering the example of the TNUoS transport model (which includes e.g. distances, asset type and capacity etc.)
- Charges based on grouping of areas and/or branches of the network into different categories, particularly where insufficient information may be available for a more granular approach, e.g.:
    - Urban/rural/industrial/residential areas

- Based on measures of how fully utilised different assets/branches of the network are, how this may change, and the driver for this (e.g. generation-dominated vs demand-dominated areas)

1.7. These options could apply to, for example, EHV only, HV only or HV and LV etc., or other hybrids approaches (such as segmentation by user type or type of network) – this should be explored. Consistency across the regime is desirable where it supports cost-reflectivity.

1.8. The aim of the first stage of work is to define these options for additional granularity and assess which may be feasible (not assessing desirability). This should include considering what is possible with network data/models that DNOs currently have or could be obtainable in the near future, for example, as part of DSO development. The sub-group should also consider in outline terms what might be the additional costs/time involved in obtaining further data/models to facilitate more granular charges.

1.9. The aim of the second stage of the work is for the sub-group to consider which options for the introduction of the additional granularity would be desirable, considering how additional granularity would support improved cost reflectivity. This should draw from the work being undertaken relating to the request for information/network cost drivers sub-group. To the extent that variation in granularity may be desirable, the group should consider the interactions between different levels of granularity, e.g. to ensure that the linkages between EHV, HV and LV maximise cost-reflectivity if different levels of locational granularity are proposed (or other variations that might consider user types, for example).

1.10. The findings of this sub-group will be used to inform the next phase of work to establish greater locational granularity of forward-looking DUoS charges. This will bring together leading options that are both feasible and cost-reflective (identified in this sub-group) with different conceptual charging arrangements (identified in workshops with independent academia). This subsequent phase will be taken forward under a new Product Descriptor. The findings of this sub-group will also be used to inform a further sub-group focused on developments to the connection charging boundary, as more locationally granular charges may enable implementation of a shallow charging boundary.

2. Deliverables and timeframes

2.1. Key deliverables and timeframes are set out in the following table.

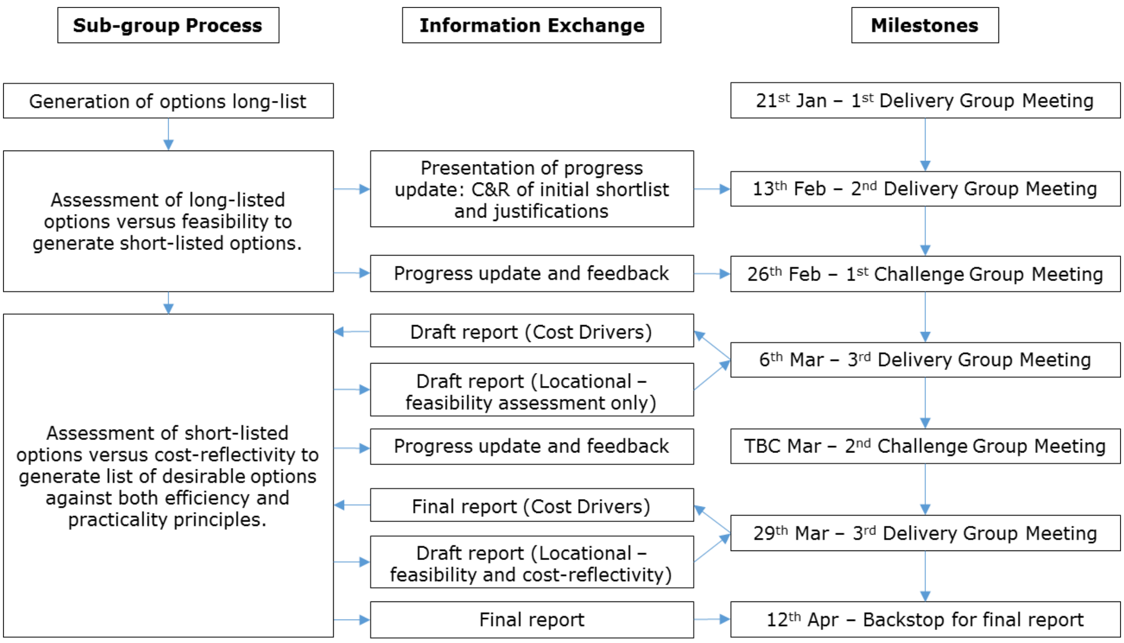
Timeframe	Deliverable
1st Delivery Group meeting on **Monday, 21 January 2019**	Ofgem to discuss project with Delivery Group and seek feedback on the Product Description. Sub-group established to take analysis forward – volunteers sought from among Delivery Group members.
By **Friday, 25 January 2019**	Finalise list of sub-group members, product description and circulate offline via email to Delivery Group.
2nd Delivery Group meeting on **Wednesday, 13 February 2019**	Sub-group to present progress update: initial options for locational granularity based on data and models availability. (can be verbal only)
1st Challenge Group meeting on **Tuesday, 26 February 2019**	Present progress update to Challenge Group. Challenge Group to provide feedback on the options presented, including feasibility (publishable presentation format)

3rd Delivery Group meeting on **Wednesday, 6 March 2019**	Sub-group to present draft advice to the Delivery Group for feedback. (draft advice in Word document report)
2nd Challenge Group meeting in **March 2019 (Date TBC)**	Sub-group to present draft advice to Challenge Group for feedback. (draft advice in Word document report)
By **29th March 2019**	Final report circulated to Ofgem and Delivery Group **(Final advice should be in a report form capable of being published)**
By **12th April 2019**	Backstop for delivery of final report to account for potential changes as a result of Cost Drivers sub-group final report.
Middle of April 2019	Draft report circulated to the Challenge Group offline
End of April 2019	Final report shared with Delivery Group for sign-off

2.2. The key final deliverable of the sub-group is a publishable report. The report should outline each of the areas specified in the detail of request section of this descriptor. The analysis should draw on the data received through Ofgem's recent information request to the network businesses as appropriate for discussion and inclusion.

Flow Chart Representation

This flow-chart added following initial sub-group meeting on 25/01/2019 to clarify interactions between this sub-group and milestones.



3. Engagement

3.1. This group is chaired by Ofgem, with coordination provided by the ENA.

3.2. The role of coordinator is ensure work is allocated appropriately among sub-group members, to organise meetings of the sub-group, and to ensure deliverables and timeframes are met.

3.3. The primary Ofgem contact for the sub-group is Patrick Cassels.

4. Detail of request

4.1. Options definition based on availability of granular data and models

- Outline the key options for increased granularity of charges at HV and LV (given that nodal granularity is already available at EHV).
- Establish limitations imposed by the availability of data and models for the HV and LV networks (taking into account planned developments in network monitoring and/or other improvements in availability of network or user data).
- Where data and models are not presently available, establish the feasibility of obtaining this information or developing improvements in available data and modelling, and in broad outline terms establish the time/costs involved.

4.2. Assessment of how well different options improve cost reflectivity

- Conduct and assessment of how different options for level of granularity could achieve greater/lesser cost reflectivity through different approaches. This should build on the outputs/analysis following the Request For Information, and the initial views of the cost drivers work group by this point. It should highlight whether options:

  1. Support additional locational granularity where the cost drivers work suggests that there are significant variations in costs.
  2. May provide unnecessary additional granularity where the cost driver work suggests that costs are relatively uniform across different areas.

- Establish where options would maintain or create different approaches at different voltages, areas or according to different user types, and assess the options for interactions between these approaches (for example, cascaded charges or all-the-way charges). Assess the key design choices and trade-offs involved in effective coordination/consistency of signals across these boundaries, and the overall desirability of proposed options in accordance with the principles of the Significant Code Review (efficiency and practicality principles only at this stage).