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Options for improving locational accuracy of distribution charges – discussion note

Summary

In this discussion note, we set out the options for reform of how distribution locational charging signals are calculated, followed by our preliminary views. The discussion note includes the options we have identified in two key areas:

- **Network cost models:** this includes the options we have identified to improve the methodologies used to estimate and attribute network costs to different users.
- **Locational granularity:** this includes the options we have identified to improve the extent to which distribution charges vary by location.

In the first section, we consider whether network cost models should seek to signal the Long Run Marginal Costs (LRMC), based on network development timescales, or the Short Run Marginal Costs (SRMC), based on operational timescales. This includes a preliminary assessment of different ways in which the costs could be determined and their feasibility. We also discuss the types of costs that could be signalled by an LRMC charge, potential modelling approaches, and who the charging signals should be sent to.

Our preliminary view is that distribution charging cost models should continue to be based around an LRMC approach. SRMC approaches may be possible in the future. However our analysis so far suggests that there are significant feasibility challenges with distribution level implementation at present. We have identified both allocative and incremental approaches to LRMC pricing as two models for further consideration.

In the second section, we consider different options for improving the cost reflectivity of charges by improving how well they reflect local network conditions. This could involve charges for customers connecting below 22kV facing charges that vary across a distribution network operator (DNO) region, rather than there being a single charge as now.

Our analysis so far suggests that it may be possible to have charges vary for customers according to which primary substation they are connected to. We are continuing to consider the extent of variation in cost drivers and the potential benefits of grouping substations to avoid undue complexity. We think that there may be merit in having charges vary according to the varying costs of the extra high voltage (EHV) network that each primary substation is connected to. In addition, we are considering the extent to which there is sufficient network mapping and monitoring to support charges varying according to differing cost drivers for the lower voltage networks. For example, we think that classifying different areas of the network as generation-dominated or demand-dominated areas may have merit, which will be an issue that we assess in more detail.

1.1. The note is set out as follows:

- Section 1: Options under consideration – network cost models
- Section 2: Options under consideration – locational granularity
- Section 3: Our preliminary considerations – network cost models
- Section 4: Our preliminary considerations – locational granularity

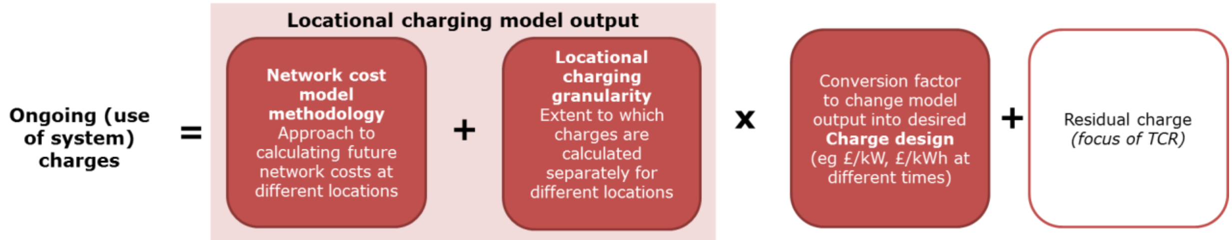
- Section 5: Summary of preliminary views
- Annex – Additional detailed design options for distribution locational cost models.

1.2. As part of our Access and forward-looking charges Significant Code Review (Access SCR), we are undertaking a 'wide ranging' review of the forward-looking element of Distribution Use of System (DUoS) charges. This includes both the Extra high voltage Distribution Charging Methodology (EDCM) and the Common Distribution Charging Methodology (CDCM).

1.3. A key part of this is examining how costs vary by location and how this could be reflected in charges. The idea is to better reflect the impact that network users have on network costs. Key aspects we identified as an issue were the excessive volatility of charges for customers connected at 11kV or above (who are charged under the EDCM), and the lack of granularity of charges for those connected at lower voltages (who are charged under the CDCM).[1] We also note that the use of different charging methodologies, based on the voltage of connection, can also create a step change in charges at the boundary between them.

1.4. DUoS is an ongoing charge levied on all users of the distribution network (or on suppliers on their behalf). In some situations (in current arrangements, generators only), it can also involve issuing credits (ie payments to users) rather than charges. It can be broken down as shown in Figure 1.

Figure 1: Conceptual breakdown of the calculation of Distribution Use of System charge



1.5. For those not familiar with the current charge design used for distribution and transmission charges, this note can be read in conjunction with our Current arrangements note.

Section 1: Options under consideration – network cost models

1.6. A key first question in how to determine forward-looking network charges is which of two conceptual options to pursue. These are different approaches for how the impact on network costs could be determined, based on the concept that charges should reflect the marginal cost of an extra unit of demand or generation on the network. Depending on this initial choice, there are then further options around the specifics of the model to be used.

- **Short Run Marginal Cost.** This is where network infrastructure is taken as a fixed consideration in charge setting. Network charges are based on the cost of

[1] See our Existing Arrangements note for further information on the current arrangements.

increasing/reducing generation and demand in real-time (or close to real-time) in order to manage network constraints. At times, the marginal cost could be close to zero (when there are no constraints), whereas at others it could be very high (when the network is constrained).

- **Long Run Marginal Cost.** This is where network infrastructure is not taken as a fixed consideration in charge setting. Network charges are based on the cost of developing the network and whether the behaviour of network users will increase or decrease these costs. Where an SRMC approach typically implies only charges are received, under an LRMC-based approach it is possible for network users to receive charges or credits, based on the extent to which they increase or decrease the network cost counterfactual (further discussed at paragraph 1.11). This is the current approach to forward-looking charging in Great Britain (GB) and is also the predominant approach used internationally for network charging.

Options for an SRMC-based charging methodology

1.7. We have identified two options for how an SRMC-based network charge could be set:

- **SRMC charge set ex-ante:** This approach would involve attempting to forecast network conditions and the marginal cost of resolving any constraints ahead of time. This forecast would be used to set the charge ahead of each time period.
- **SRMC charge set ex-post:** this approach would aim to calculate the SRMC price of each time period after the time period had finished, based on the constraints that occurred and any curtailment actions that the DNO needed to implement.

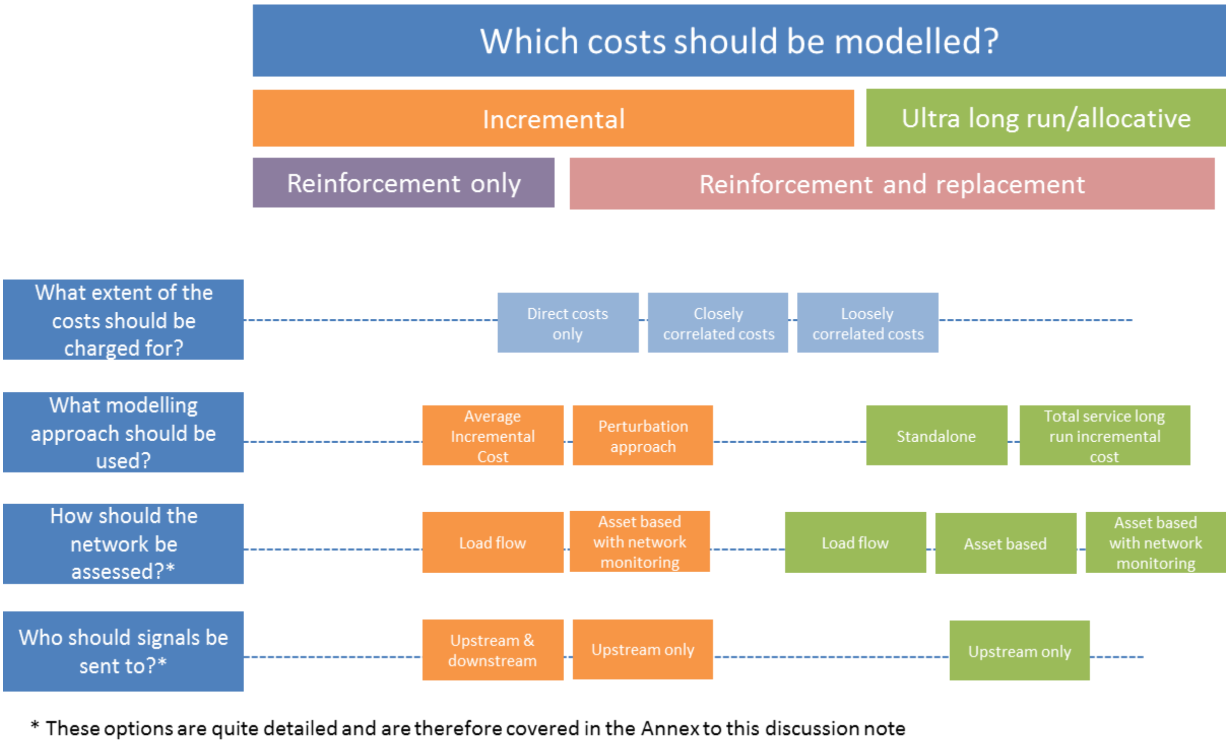
1.8. An alternative way in which an SRMC signal could be determined is through a market-based mechanism. A particular example of this is via Locational Marginal Pricing (LMP). This is where network constraints are accounted for within the wholesale energy market by allowing prices to vary locationally. This approach ensures that demand is met by the least cost generation, subject to the resulting flows on the network not exceeding available capacity.[2] We have not included this type of option within our assessment as it is outside the scope of the Access SCR (due to the practical challenges of implementing this approach at a distribution level). For completeness, we recap our reasoning for this in the Preliminary Considerations section.

Options for an LRMC-based charging methodology

1.9. Under an LRMC-based approach, there are a number of different methods that could be used to estimate long run costs. Figure 2 outlines these options, illustrating how the key high-level choice of which costs should be modelled influences the options that can be taken on a number of the subsequent design choices.

[2] This is achieved by overlaying users' energy bids and offers with a model of network capacity availability close to real-time.

Figure 2: Key design questions for an LRMC approach



Which costs should be modelled?

1.10. Within an LRMC-based approach there is a further decision to be made on what kind of network infrastructure costs to model. A key distinction between methodologies is whether to focus on signalling network costs that are likely to be incurred in the near- to medium-term or not:

- "Incremental cost" methodologies that provide a signal, based on the cost of a marginal addition of demand or generation, to indicate where/when they will result in network costs within a given timeframe (eg 5 years). This approach could be further divided into two:
  1. Signalling just where reinforcement costs may be incurred in future, as a result of a lack of spare capacity on the existing network
  2. Also signalling where existing network assets will need to be replaced in future, where a marginal increase or decrease in flows over the network could change the cost of replacement works.
- Methodologies that do not take into account spare capacity/remaining lifespan of the existing network. This type of methodology could be labelled as an "ultra long-run approach" based on the idea that, at some point in the future, a marginal addition of either demand or generation will require either investment in new network capacity (reinforcement) or replacement of existing capacity. The strength of the signal provided is not impacted by how long in the future those costs might be incurred. Alternatively, they can be seen as an "allocative" approach, determining how a marginal addition of either demand or generation uses the existing network and allocating costs in a cost-reflective manner based on this. This can be considered to send a forward-looking price

signal to the extent that future network requirements consist of a similar asset mix to that which exists already.

What is the extent of costs to be charged for?

1.11. The extent of the costs that can be associated with reinforcement or replacement is a key decision to be considered. The network cost model could just take into account costs that are directly involved with a particular reinforcement or replacement and are related to the physical asset, such as the overhead lines or underground cables that are installed to reinforce an area of the network. At the other end of the spectrum are costs such as call centres, which are only very loosely correlated to the costs involved in developing and maintaining network capacity, and therefore an assessment of network development may not be an appropriate basis to allocate these costs to network users.

1.12. While there is a spectrum of possible approaches here given the range of different cost categories, for the purposes of this discussion note we consider three conceptual categories:

- **Include direct costs only** – which would include just the electrical assets required for the network reinforcement or replacement work.
- **Include closely correlated costs (plus direct costs)** – which could include costs such civil works, network repair and maintenance and possibly less closely correlated costs such as business rates and smart meter costs.
- **Include loosely correlated costs (plus direct and closely correlated costs)** – which could include costs such as call centres.

Who should signals be sent to?

1.13. In developing a network model, it is also important to consider which costs will be signalled to different users – specifically, whether generation and demand should receive equal and opposite charges/credits, and whether charges should be based on a user's impact on upstream costs (ie costs at the voltage they are connected to and above) only or also on any downstream costs that they contribute to. Our analysis so far suggests that these decisions are closely linked, and that there are two distinct approaches that could be coherent:

- **Generation and demand receive equal and opposite charges/credits, with signals covering upstream costs only.** This would involve a) the model only assessing the impact that users have on the network at the voltage they are connected to and at voltages above that; and b) where a user contributes to those upstream costs, they would need to pay a charge, and, if they help offset them, then they would receive a credit. We note that the status quo arrangements for EDCM distribution charging follow this approach, with the exception that b) is not met in generation-dominated areas where there are flows going back up the network.
- **Users pay charges for either upstream or downstream flows they are contributing to, with no opposite credits.** This would involve the model assessing the impact a user has on either upstream or downstream power flows. Those adding to dominant flows would pay a charge, while those offsetting dominant flows would not receive a credit.

1.14. At transmission, the "reference node" is used to help derive the TNUoS locational charges for different users and areas. We decided to include the reference node within the scope of the SCR. Further information on the options for reform will be included in our second working paper that will be published later this year.

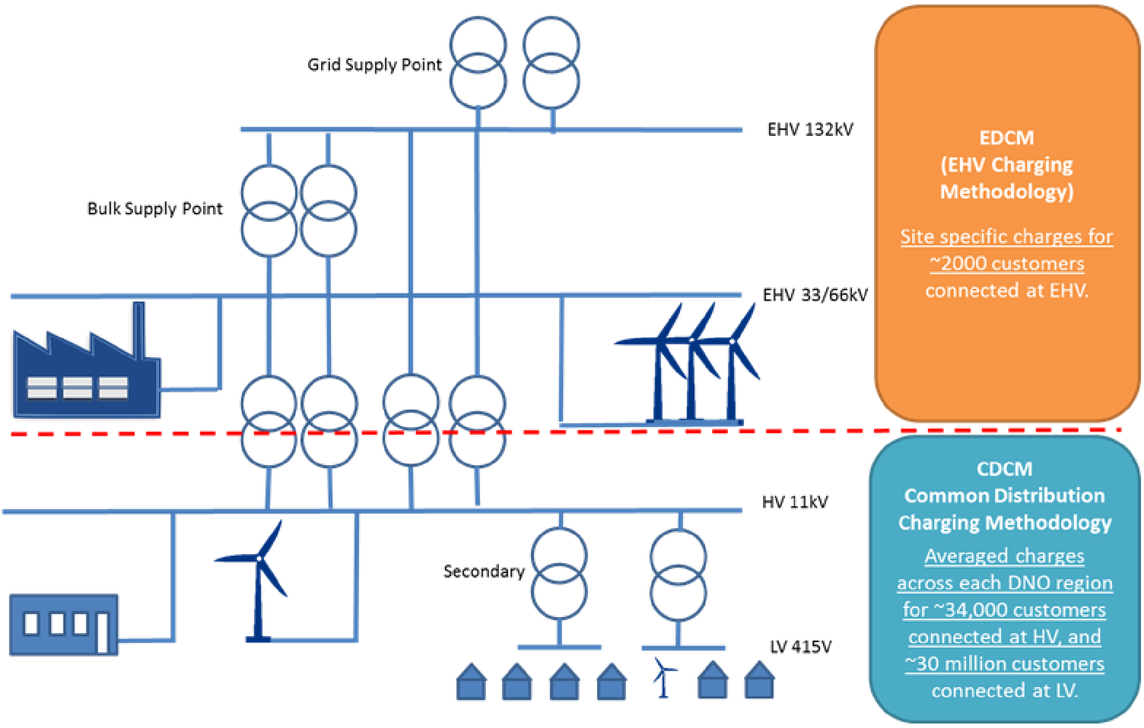
Section 2: Options under consideration – locational granularity

Options for integrating locational signals across voltages

1.15. Currently, there are three models used for calculating charges for users connected to the distribution network. These are Forward Cost Pricing (FCP), Long Run Incremental Cost (LRIC), which are both defined under the EDCM, and the Asset Replacement Model (ARM), also known as the "500MW model" and defined under the CDCM. Additionally, there is the Transport model, which calculates Transmission Network Use of System (TNUoS) charges.

1.16. For designated EHV properties (which includes "HV sub" customers), they will be charged on the basis of either FCP or LRIC (depending on the DNO region) and the users connected at HV or LV network will be charged on the basis of ARM. The ARM charge is an "all the way charge", which means it accounts for the user's requirement for using the EHV network also. This is illustrated in Figure 3. All distribution-connected users also pay TNUoS charges.

Figure 3: Distribution network topography and application of existing charging methodologies



Note: HV may include 6.6kV and 22kV in some areas

1.17. We are considering whether other options could provide better cost-reflective signals by reducing the risk that charging boundaries distort behaviour. We are also considering whether there may be value in combining or extending the models, as part of developing options for improved cost models and locational granularity. Options include:

- **Changing how customers connected at low voltage (LV) and high voltage (HV) are charged for their impact on EHV costs.** This could move away from a model where EHV costs are averaged across a DNO region to one that is more locationally granular. One option would be for EHV charges to be calculated for all primary substations under the EDCM, and then passing these down to the customers connected under each primary substation.
- **Consolidating the models used for the EDCM into a single model.** This could be one of FCP or LRIC, or could be extending the use of the Transport model to that level.

1.18. These options are not exclusive. Additionally, this list is not comprehensive and there are a number of different possible permutations. We may identify further options as we advance our views on what options for improved cost models and locational granularity may have merit.

Options for locational granularity of charges

1.19. We have identified the following basic options for the implementation of locationally granular charges. These are classified according to whether they would generate a nodal charge (specific to the location of each individual customer), or "zonal" charges (where the locational charge could apply to multiple customers, depending on how the zone is defined).

- **Nodal charging:** This is a fully granular option for setting network charges which would involve setting a customer-specific charge for network users. Presently, this approach is taken only for users connected to the EHV network whose charges are calculated using the LRIC methodology.
- **Zonal charging:** This is a less granular option for network charging, which would involve setting averaged charges on a zonal basis, though possibly with separation into further groupings to reflect variations in users or networks within each zone. This would mean that all users in a given zone (or groups within a zone) would face the same charge.
- **Hybrid charging:** This would involve extending nodal charging down to a certain voltage level and applying zonal charging below that point. This option may enable more cost-reflective charges to be produced by making use of the availability of better quality network data at higher voltage levels. The current approach is an example of this, as there is a customer specific charge for users connected to the EHV network, and a highly averaged zonal charge for users of the HV/LV network. There may be scope for more granular groupings to improve the accuracy of the signal within these highly averaged zones.

1.20. We have, therefore, taken a two-step approach to considering how locationally granular network charges may be achieved. Firstly, we have considered the options for how far down the network voltage level it might be possible to achieve a fully nodal charge:

- **Nodal charging to the primary substation.** Zonal charging below each primary substation. This would involve setting different charges for customers connected under different primary substations[3] (~5,000 substations) based on the network variations asset mix below each primary substation.

[3] Note that this option is reliant on being able to link network users to a substation (or group of substations) in order to determine what charges they face.

- **Nodal charging to the distribution substation.** Zonal charging below each distribution substation. This would involve setting different charges for customers connected under different distribution substations (~600,000 substations) based on the differing asset mix below each distribution substation.
- **Grouping nodes into small zones under either option above.** Zonal charging below that point. Whilst the current precedent is for the EHV network to be charged nodally (under the LRIC model), there may be a case to group nodes into small zones or branches (similar to the FCP model and approach at transmission level). Although potentially less cost-reflective, this averaging process could help to stabilise the charge and thereby improve users' ability to respond. This cross-cutting consideration could apply to either of the two nodal options above.

1.21. Secondly, we have begun to consider options for how more granular charges could be achieved below the point of nodal granularity (whether at primary or distribution substation level) to improve cost reflectivity below the point at which a customer-specific charge is produced. These options are not necessarily mutually exclusive as there could be multiple distinctions or classifications that help to improve cost reflectivity, though there would be a trade-off with increased complexity of charges:

- **Grouping by geographical proximity or electrical connectivity.** This could involve grouping substations in a similar location based on geographical proximity or their electrical connectivity.
- **Grouping by archetype based on customer/network characteristics.** This could involve grouping customers based on shared characteristics that link to cost drivers (eg intermittent or non-intermittent users) or grouping the network according to shared characteristics (eg rural/urban network classifications could be a way to capture different costs).
- **Grouping by network loading.** This could involve grouping substations based on how heavily loaded they are (eg charging all users connected below a primary substation based on the load index). A higher loading could indicate that an area of the network is nearer to a reinforcement requirement. It could also involve altering charges based on whether generation or demand is driving the requirement (ie whether the area is generation or demand dominated).

Section 3: Our preliminary considerations – network cost models

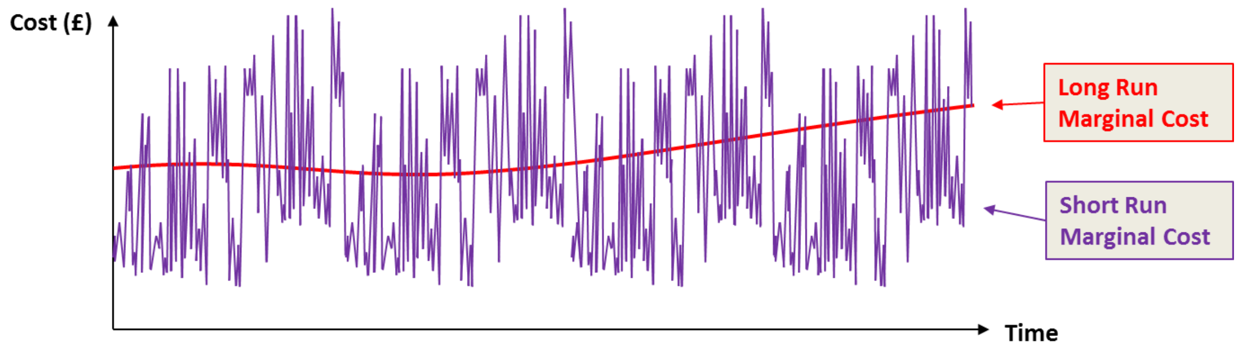
Determination of marginal cost

1.22. The aim of forward-looking charges is to provide network users with cost-reflective price signals, based on how they impact future network costs. It is a well-established principle in economic theory that price setting should focus on marginal costs to promote the efficient use of goods and services – in this context, with respect to the use of the network. A key question, particularly for monopoly assets, is what time-frame should be the focus of the marginal cost assessment.

1.23. As outlined in the previous section, network charges could conceivably aim to send signals about either SRMC or the LRMC of the network. Our initial investigatory work supports a view that choosing to set network charges for the same network costs according to one of these approaches should be a clear binary choice – that is users shouldn't be charged SRMC and LRMC for the same costs. It may be possible to charge a user both LRMC and SRMC, if those charges relate to different types of costs.

1.24. The SRMC and the LRMC should approximate each other where there is efficient build of the network (Figure 4). This is because investment in new network capacity (the LRMC) should occur once it becomes cheaper than the expected future SRMC of managing constraints to existing network capacity limits.

Figure 4 - Comparison of SRMC and LRMC over time



1.25. Based on this principle, charging for the same costs twice under both LRMC and SRMC approaches could risk double charging. However, this does not preclude signals for market response in both short run and long run timescales. For example, currently generators over 100MW face an LRMC, charge based on their agreed capacity, and can then receive short-term operational signals to support network management through the Balancing Mechanism.

1.26. Choosing to opt for either SRMC or LRMC-based forward-looking charges is likely to lead to significantly different and potentially divergent design choices. Therefore, we have set out our current assessment in order to facilitate more focused options development.

Short Run Marginal Cost based charging options

1.27. SRMC-based approaches theoretically send a more accurate signal to users that reflects the network costs of their decisions in operational timeframes (eg whether to generate or consume at a particular time). Congestion on distribution networks has historically been very low, as has explicitly incurred short run costs. This is because DNOs historically achieved the requisite levels of security of supply through network assets only, ensuring sufficient redundancy of network assets to meet demand, as required by the planning standards.

1.28. This historical position is now evolving with growth in procured flexible alternatives to conventional network asset investment and other improvements to facilitate more efficient network utilisation. DNOs are increasingly seeking to achieve security of supply through flexibility services from network users where it is economically efficient to do so (this could be through the DNO procuring services or through users opting for more flexible access choices). As a result, DNOs or users may begin to more explicitly incur short run operational costs to support network management. For these reasons, we felt it was appropriate to consider options to set charges on a short run basis.

1.29. The options for an administratively set SRMC-based network charge can be considered in terms of whether the charge is set **ex-ante** or **ex-post**. We believe that either of these options are compatible with the scope of the SCR, and have set out our current thinking accordingly below.

1.30. For both options, SRMC charges are based on the costs of users turning up and down in real-time to ensure that power flows do not exceed the fixed capacity of the network in operational timeframes. As such, the network charge would have to be updated on a highly dynamic basis to reflect the prevailing network conditions and user preferences in real-time. This leads to a significantly more volatile charge, based on whether the network is congested or not and how the price users will need to be paid to turn up or down (their opportunity cost) varies over time. A static charge - for example, one that is reviewed and set on an annual basis - would therefore not be compatible with the principles of SRMC charging. We discuss different charge design options in the Charge design options for distribution and transmission charges discussion note.

1.31. We also recap and update our previous high-level assessment of LMP below.

SRMC charges set ex-ante

1.32. This would involve setting the charge ahead of time and forecasting both network and market conditions to a high degree of accuracy in order to derive cost-reflective signals for each future charging period. Setting the charge closer to real-time may help to reduce the error in the forecasting of network and market conditions.

1.33. This approach would be highly dependent on a highly granular and detailed model of the network, with sufficiently widespread network monitoring to be able to determine the short run impact of the additional increments of generation or demand in any given location. The Locational Granularity of Charging report[4] produced by the Delivery Group concluded that, within the timescales of the Access SCR, network monitoring could only be ubiquitously available to a primary substation level and that monitoring of HV and LV networks would not be sufficiently granular or widespread for charging purposes. This presents a significant challenge to the feasibility of SRMC-based charging approaches, particularly given the variability in network flows at different times and in different locations.

1.34. It would also be highly dependent on the ability to produce an accurate estimate for the cost of actions that would be required in the market to manage network constraints. In order for the charge to set an accurate short run marginal price, DNOs would need to accurately forecast the cost of actions they would have to take to alleviate network constraints in the absence of the charging signal being in place. We consider that this would be extremely difficult to predict accurately – with sufficient locational and temporal granularity – as there would be no market-based mechanism to help discover the true price of these actions.

1.35. Our assessment of this option is that it therefore does not seem to be workable in practice. SRMC is based on the willingness of network users to increase or decrease their output, therefore determining the charge ahead of time would present a significant modelling and forecasting challenge. It could risk exposing users to a highly dynamic and volatile charge that does not accurately reflect the underlying network costs incurred.

[4] Locational Granularity of Charging report: http://www.chargingfutures.com/charging-reforms/access-forward-looking-charges/resources/

SRMC charges set ex-post

1.36. Setting an SRMC charge ex-post would require operational actions to be taken to manage the network constraints in real-time, and the cost of these actions then charged back to users of the network after-the-fact. This approach could conceivably encourage users to attempt to forecast and avoid those periods where they expect that the ex-post network charge is likely to be high. Given the highly dynamic nature of SRMC signals, this would have to be an ongoing process – again, to a very high degree of locational and temporal granularity.

1.37. In practice, we believe that this option could similarly result in a highly volatile charge. It would also be difficult for users to effectively respond to. Whilst the charge would be accurate to the costs incurred in this case, the ability for the market to accurately forecast and respond to ex-post SRMC charges on an ongoing basis is likely to be limited. For this reason, we do not believe that an ex-post SRMC charge would be sufficiently predictable to be a workable option.

Locational Marginal Pricing (LMP)

1.38. LMP is an alternative to setting SRMC based charges administratively, which involves allowing wholesale electricity market prices to vary by location for each market period. This enables the market to deliver competitive price discovery based on the value of network infrastructure to network users at each given location on the network close to real-time. The resulting price variation is reflective of variations in the value of network infrastructure to electricity network users at different times.

1.39. LMP therefore achieves similar outcomes to the concept of SRMC network charges via alternative means. Because LMP enables competitive price discovery (rather than administratively set charges) and combines energy and network costs within a single price, it is generally regarded to be the theoretically 'first best' solution to accurately pricing the network. However, it presents numerous feasibility challenges and complexities, particularly for distribution-level implementation.

1.40. Under an LMP-based model, locational prices can be highly volatile, based on whether the network is constrained in each market period. Where LMP has been used internationally (focused at the transmission-level) to prevent network users from being directly exposed to this volatility, the framework allows market participants to purchase long-term hedges against volatile real-time wholesale prices.

1.41. Typically this involves the system operator taking on the additional function of defining and auctioning financial instruments that are reflective of the network constraints that may arise. The idea behind this model is that the revenue is a key input into the justification for new network infrastructure.

1.42. Whist LMP seems attractive in theory, we note that it entails significant feasibility challenges, including:

- The framework to allow for hedging is very complex.
- It would involve a fundamental redesign of the wholesale electricity market. Particularly, most LMP models involve market clearing and dispatch decisions being centralised and determined through an algorithm, which would be a major change from our current system of self-dispatch.

- Network models and monitoring – LMP is highly dependent on highly granular, rich network data that is kept well maintained. This is necessary to determine how hedges are defined and manage network constraints in operational timescales.

1.43. Notably, we are not aware of any examples where LMP has been introduced at a distribution-level on a national basis. This is largely due to the very significant practicality issues. The possibility to extend LMP to distribution networks ("D-LMP") is possible in theory and is an area of active research and investigation. However, this significantly increases the complexity of arrangements and degree of feasibility challenges. This includes both challenges with sufficient network data and computational power, and potentially increased difficulties in establishing an effective hedging market which could need to include smaller users (including consumers). There is the additional risk that there could be insufficient liquidity in hedging markets for very localised distribution network constraints, with a low number of market participants behind them.

1.44. Implementation of LMP in GB would require broad reforms to wholesale electricity markets and system operation. For these reasons and others, it is out of scope of this SCR.

1.45. In summary, our analysis suggests that it is extremely difficult to send an accurate signal for an SRMC-based network charge (if set ex-ante), and extremely difficult to predict and for network users to respond to a highly dynamic and volatile SRMC signal (if set ex-post). For these reasons, we do not presently anticipate shortlisting SRMC-based charging options for detailed consideration. We consider that LMP would be a better way to send short run charging type signals as it allows market-based price discovery, but continue to believe the practicality challenges mean it is not viable in the nearer-term and so maintain that it is not within the scope of this SCR.

Long Run Marginal Cost based charging options

1.46. LRMC charges are derived from the cost of network infrastructure, when costs are assessed in network development timescales. This generally leads to more stable and predictable charging signals, although this is dependent on further design choices discussed below. Unlike SRMC, LRMC charges are compatible with either static or dynamic charging designs.

1.47. The greater predictability of LMRC-based charges means they have the potential to better inform user investment decisions, such as whether and where to invest in certain energy services (eg storage) or demand technologies (eg electric vehicles (EVs) and associated charge points) given what this would mean for network costs. They can also help inform the case for network reinforcement or replacement, as this should only go forward if there is sufficient demand from users for them, once they have taken into account the costs of them (ie they have shown willingness to pay).

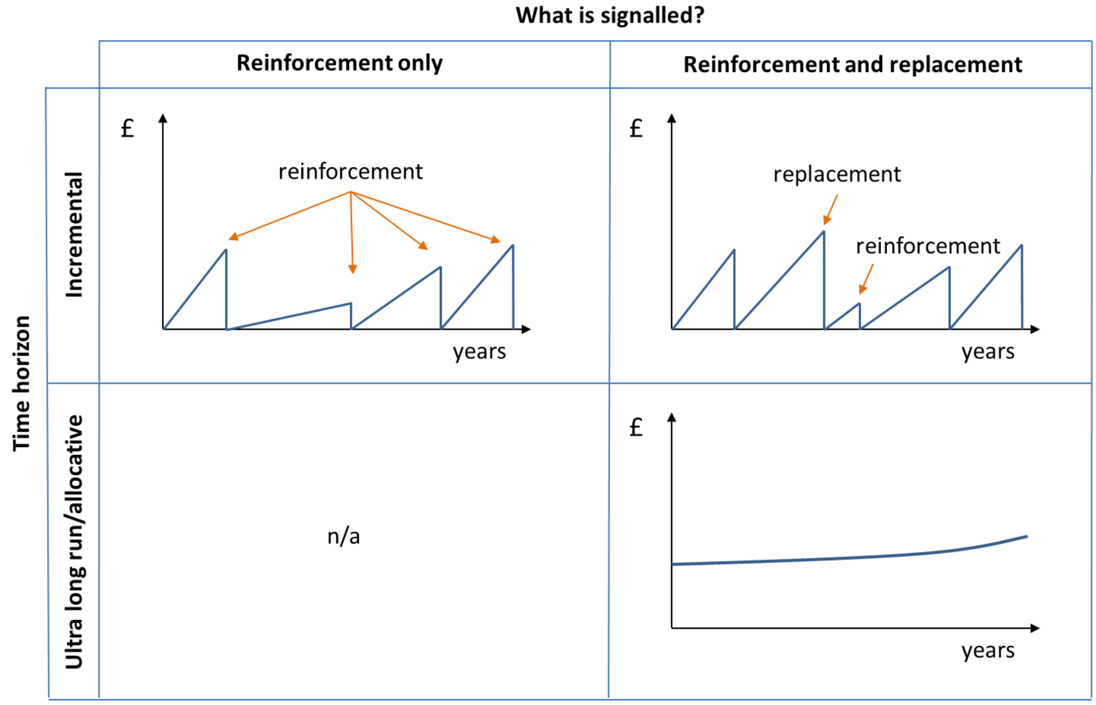
1.48. A drawback of LRMC charges is that they do not provide the same level of accuracy of signal to users about the value of their decisions in operational timeframes, as SRMC charges could theoretically provide. Flexibility markets – such as DNOs procuring services from providers who can dial imports/exports up or down when needed to avoid network congestion – could work alongside the charging signals to ensure that users get the right signals to support efficient operation of the network in real-time. The links between flexibility and the access and charging reforms are more fully explored in our Links with procurement of flexibility discussion note.

1.49. Our initial review of international examples suggests that current practice both in GB and internationally is for network charges to be based on some measure of LMRC. As we have set out, if choosing an LRMC-based approach, then there are a number of further design choices to be made. These have different pros and cons in terms of how well they meet our Guiding Principles (described in our Context and our approach note). The rest of this section outlines our initial considerations on this for the different design choices.

Which costs should be modelled?

1.50. Figure 5 shows illustrative charges under different LRMC methodologies. Each of the charts plots the charge for a user over time (in years).

Figure 5: Different options for reinforcement/replacement signals and time horizons



1.51. Under incremental LRMC approaches, the charge only rises above zero when the network cost model foresees that network reinforcement or, under the right hand side option, replacement of existing infrastructure is likely to be needed within a certain timeframe.

1.52. The benefit of such an approach is that it means that the signal is sent at the time when a change in behaviour has the most chance to lead to an immediate reduction in network costs, if it can defer or reduce the need for either reinforcement or replacement. For example, in the context of signalling reinforcement costs, relative differences in charges at different locations will provide signals about where there is more spare capacity. To the extent to which this can encourage users to locate where there is spare capacity, then this can reduce nearer-term network costs.

1.53. We see the downsides of an incremental LRMC approach are:

- The charges produced under either incremental LRMC approaches are inherently more volatile. This can make it hard for users to predict and respond to the charging signals, which could negate the potential behavioural benefits. We have heard lots of anecdotal evidence that this is how customers connected at EHV perceive the EDCM charge – that it is so inherently unpredictable that they do not factor it into their decision-making. However, we recognise that some of the volatility is driven by the modelling inputs, and not just the incremental nature of the modelling. Work is ongoing in this area to understand the drivers of EDCM volatility.

- Linked to this, to follow an incremental LRMC approach there is a need to make assumptions about future load growth on the network. This is inherently uncertain, particularly given how the energy system is transforming. This leads to the risk that the charge is based on spurious forecasts about the future.
- This approach does not reflect all costs onto users, as the charge is only above zero for a short period until falling back as and when reinforcement does occur. Given that network charges are set based on annuitised infrastructure costs over a 45 year period, this means that users are only facing a small fraction of these costs through the forward-looking charge, and are not contributing to ongoing costs they cause, following the point that reinforcement is undertaken. This may limit the extent to which the charge provides an effective incentive for users to change their behaviour, as they know that increased charges could only be temporary until additional capacity is in place. This problem is particularly acute for the reinforcement only approach (which puts more costs into the residual), where, once capacity is in place, users may face no charge, despite the fact that in time there will be a need to replace network assets to maintain that capacity.
- This model has greater requirements for network information to support it. The EDCM uses sophisticated load flow modelling but this is only possible at higher voltages where there is sufficient network information and so would not be possible at all voltages. It is conceivable that an incremental long run approach could be undertaken using asset based modelling with network monitoring. This requires less network information than load flow modelling but still may not be possible for all voltages. This is discussed further below.

1.54. The benefit of an ultra long run or allocative approach is that it can provide a more stable signal to users about the costs of using the network over the long term. It also gives a better indication of whether users are willing to pay for network assets to continue to be maintained and for reinforcement when this is needed (as they will face the cost of the network they are using on an enduring basis, rather than the costs falling away once reinforcement or replacement has occurred). Such an approach is not as reliant on detailed network data (reflected in that it is currently used for the CDCM) and does not need to make forecasts of future network loads to set charges. However, it will not send signals to users about where there is spare capacity in the network, or where their continued use of the network is going to contribute to the need for asset replacement in the near-term.

1.55. We consider that there is a reasonably strong case for signalling replacement costs through forward-looking charges, whether through an incremental or ultra long run approach. This is because replacement costs are a major driver of network costs – as shown in Figure 12 included in the annex to this discussion note, which sets out total DNO costs for RIIO-ED1. Currently 13% of DNOs' annual expenditure during the RIIO-ED1 period is on the direct costs of replacing ageing network infrastructure (though we note this percentage may change, as reinforcement costs could grow in future given the energy system transformation). By continuing to use the network, users contribute to the need for asset replacement, and at the margin, reductions in network flows could reduce the scale of future network replacement activity.

1.56. We do not yet have a clear view on which of these approaches would best support our Guiding Principles and will continue to consider this. In doing so, we will carefully consider the different benefits in providing cost-reflective forward-looking charges and the relative importance of these. We consider that these are:

- Providing a cost-reflective signal can encourage users to modify their behaviours to reduce network costs. This could provide short-term network cost savings (such as by locating where there is spare capacity to avoid near-term reinforcement) or savings over the longer-term (such as generation locating near to demand so that less network assets are needed in future).
- Even where behaviours do not change in response to cost-reflective charges, this can still provide a useful indicator about users' willingness to pay for new network infrastructure, supporting efficient development of the network.
- Cost-reflective signals can also support effective competition between providers of energy services, ie ensuring that competition between them reflects their full underlying costs, so that the most successful are those that can drive most value for consumers. This means that individual providers may not change their behaviour but the mix of providers who succeed in the market could change, due to charges properly reflecting underlying network costs.
- For consumers, cost-reflective signals can also help guide equitable allocation of future network costs, as it is arguably fair that users pay for costs they contribute to. We recognise that this argument is not clear-cut, particularly for consumers in vulnerable situations, and intend to consider it further in our second working paper.

1.57. There may be some hybrid approaches that allow the merits of the incremental and ultra long-run models to be combined. For example, one option could be to adapt an ultra long-run/allocative approach so that charges are discounted in areas where there are significant levels of spare capacity. We intend to give this further consideration in our next phase of work.

What is the extent of costs to be charged for?

1.58. Figure 12 in the annex of this discussion note also shows a breakdown of DNOs' expenditure forecasts with respect to historical spend. This shows that the direct cost of reinforcement and replacement during the RIIO-ED1 period amounts to 18.3% of DNO spend. A narrow approach to setting forward-looking charges would be to just estimate these costs within the charging cost model (or only reinforcement costs if that option is followed). However, there are a number of other DNO costs that are closely related to these reinforcement and replacement costs. For example, once network infrastructure is built and being used then there are subsequent costs involved in operating those assets. Where the extent of these costs is closely driven by the size of the network (based on users' decisions around location and usage of the network) then there is a case for these costs to also be included in forward-looking charges alongside the direct cost of new network infrastructure.

1.59. Our initial view is that there are some costs that seem to be more strongly correlated with the size of the network, such as:

- Repair of faults
- General repair and maintenance
- Business rates
- Tree and overhead line clearances
- Diversions.

1.60. Whereas other cost categories are more weakly correlated and so inclusion within the forward-looking charge would risk not being cost-reflective.

1.61. We intend to further consider these costs and the extent of correlation with the size of the network, and whether there is a case for including strongly correlated costs within the charging model.

Who should receive the signal?

1.62. Our current network charging approach has been developed on the premise that power always flows downwards through the network (ie from the transmission level down through the distribution voltages). This was drawn from the past where most (centralised) generation was connected at the transmission level. Based on this, charges for demand customers were based on the premise that they contributed to the need for network capacity at all voltages above them, ie they paid charges based on upstream network costs. It has also been assumed that what generation there was connected at lower voltages (distributed generation) would always offset the dominant downward flows and so should always get charging credits to reflect this.

1.63. The electricity system no longer functions like this, with flows increasingly going both upwards in areas of the network where there is significant distributed generation ("generation-dominated areas"). This is likely to become increasingly common as we decarbonise the power system.

1.64. We therefore thought it important to reconsider whether the approach of basing a user's charges on their contribution to upstream flows only (ie ignoring their impact on downstream flows) continues to make sense. In doing so, we think it is important to consider:

- Whether the forward-looking charge provides the right relative signals about how a user's contribution to network costs will vary if locating, or making operational decisions, at different points on the network. We see this as fundamental to ensuring effective forward-looking charges.
- Whether the forward-looking charge a user would pay at different locations reflects network costs in absolute terms, ie if a user's actions would add costs to the network then they should face a charge that broadly equates to those costs. We see this as desirable but not as fundamentally important as getting the right relative signals.
- Whether users that can help mitigate future network costs can readily access the value they provide.

1.65. We have assessed how well these criteria are met in relation to the status quo. The annex to this discussion note walks through some examples of different network configurations for both the status quo and options we discuss below. It is clear to us that there are a number of problems with this approach – in areas where the dominant peak flow is upwards then parties do not face cost-reflective charges in either relative or absolute terms (because demand is paying charges while offsetting the peak flow, while generation is receiving credits while contributing to peak flows).

1.66. This could be improved through changes such that charges and credits (for time-of-use charges) to flip in such situations, such that the distributed generation were paying the charge and demand receiving a symmetrical credit. We think this would ensure that parties receive the right relative signals about their contribution to network costs. However, the fact that charges are based on upstream costs only would mean that there could be situations where users' charges do not reflect their contribution to network costs in absolute terms – for example a demand user who is connected at a high voltage would not face a charge for the cost of flowing power to it through the downstream network. Under this option users that are able to mitigate future network costs are clearly able to access the value they provide as they receive credits.

1.67. We think that the alternative approach that would help ensure better cost-reflective charges in absolute terms would be to charge users for either upstream or downstream flows they are contributing to, but with no opposing credits. We think this would ensure that users face charges that reflect both the right relative cost differentials between locations and the right level of absolute costs. However, it does mean that credits would no longer be paid to those offsetting network costs (as to pay them credits would mean the right relative cost differentials were no longer maintained). This may make it hard for those users to access the value they are providing the network.

1.68. We intend to consider these issues further. We recognise that moving away from the current system of charges and credits would be a substantial change and would need strong justification, particularly if it means that users who can help mitigate future network costs could not readily access the value they provide. Our initial view is that, providing the relative price signals are right, it is not clear that ensuring cost-reflective charges in absolute terms in all situations would be sufficient to make such a change worthwhile.

Section 4: Our preliminary considerations – locational granularity

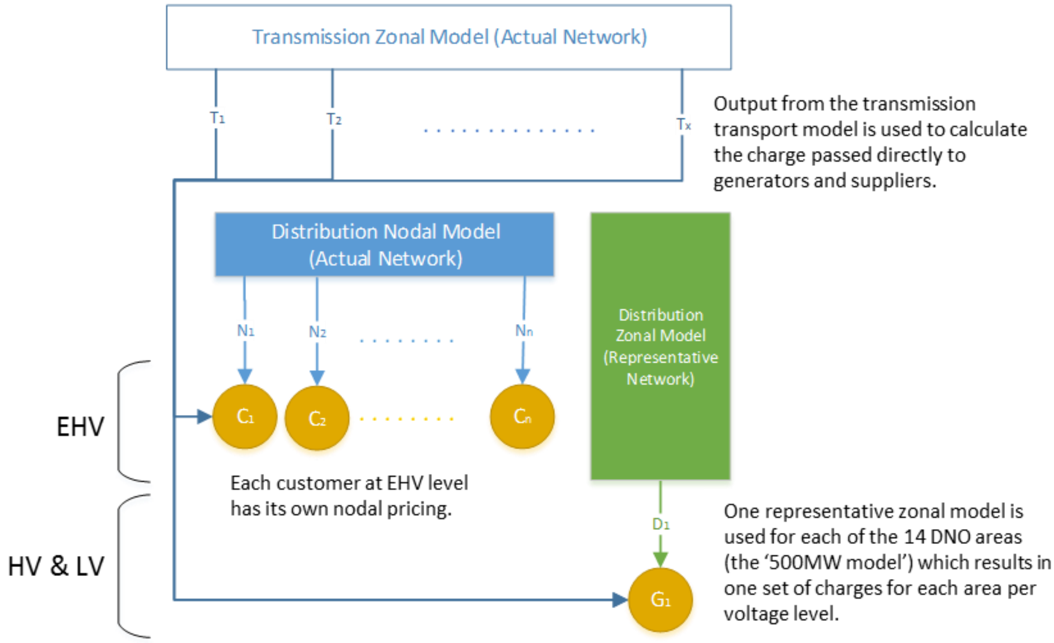
Integrating locational signals across voltages

1.69. Improvements to the locational granularity of charges is one of the initial areas which has been investigated by the Delivery Group. A detailed report[5] summarising their considerations was published earlier this year and we have drawn on this evidence to inform our current working positions.

1.70. The Delivery Group 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 customers' use of the distribution network. A zonal representative network model is used for HV and LV customers' use of the distribution network. These arrangements are illustrated in Figure 6.

[5] The report on locational granularity of charging is available at the following location: http://www.chargingfutures.com/media/1341/scr-locational-granularity-of-charging-report-v11.pdf

Figure 6: Representation of current charging arrangements

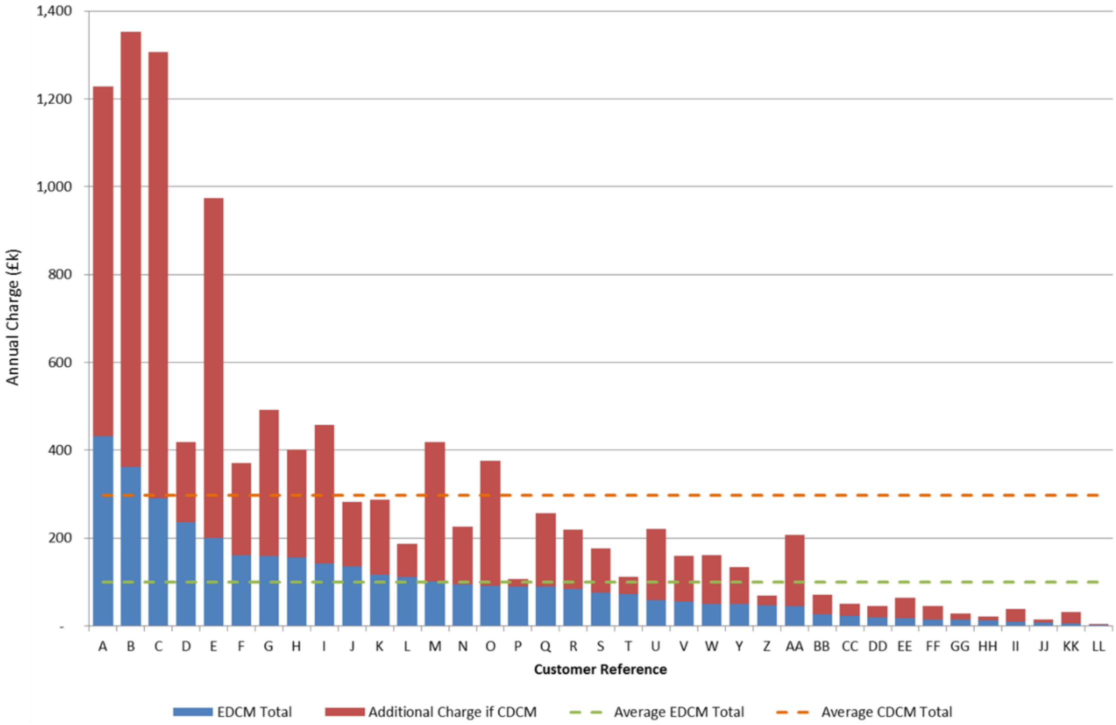


1.71. This approach creates changes in the charges which a user faces depending on where they connect to the network, which are not always reflective of the different cost drivers, but are more directly related to the differences between charging methodologies. This is because the EDCM and CDCM use fundamentally different cost model approaches to determine the impact of a user on the same EHV network, and the charges are calculated and applied to a different level of granularity.

1.72. The distortions that this creates are most readily observed at the boundary between the methodologies. 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 their charges for use of all distribution voltages calculated using the CDCM.

1.73. Figure 7 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 (ie 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 c.200%, but could be as much as c.700% in the most extreme case.

Figure 7: Comparison of how DUoS charges for different customers would change if they were connected on the HV side of the primary substation rather than the EHV side (source: Northern Powergrid Yorkshire area)



Such a significant change in charges is unlikely to be reflective of the additional cost incurred by the DNO in developing a short section of HV network. The impact of a customer connected to direct to a primary substation compared to that of an equivalent customer connected to a short section network (at the same primary substation) will be very similar.

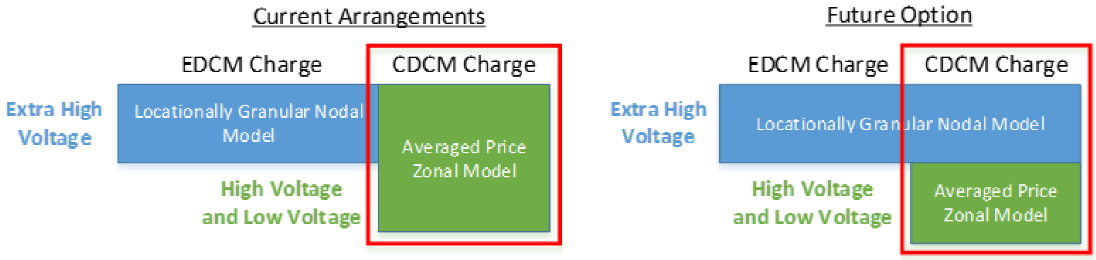
1.74. The differences are therefore likely to be a consequence of the different cost model methodologies used (given that they account for different costs), and the granularity to which the charge is calculated. With regard to the latter, in this example the short section of HV network would be charged for on the basis of the average cost of the entire HV network in the DNO area.

1.75. As highlighted in the prior network cost models section, the EDCM only accounts for reinforcement costs that are anticipated to be incurred in the nearer-term, as opposed to the broader "total service" costs that are accounted for under the CDCM. Any approach which considers a given cost driver at one voltage level but not another is likely to be distortionary, and could ultimately skew cost recovery between voltage levels.

1.76. We believe that the difference in these methodologies could presently be the most significant contributing factor the differences we observe. This presently has a significant impact on the charges that a user faces which could be due to regulatory artefacts rather than genuine cost differentials. We are of the view that our changes to the locational granularity of charges should to attempt to provide cost-reflective signals for network consistently across voltage levels where possible.

1.77. An option under consideration is whether we could disaggregate the EHV component of the "all the way tariff" to provide a more locational signal to HV/LV users based on the locational impact that they have on the EHV network. This is illustrated in Figure 8.

Figure 8: Comparison of current 'all the way' charge versus future 'layered' charge option



1.78. The current arrangements mean that although the EHV network charge is calculated to a high level of granularity for EHV connected users, this locational signal is not passed down to users connected at HV and LV.

1.79. We believe that there could be merit to this option, particularly if the existing distinctions in cost model methodologies between voltage levels are retained. A granular signal is already calculated for those customers who are charged under the EDCM who connect into primary substations at the EHV/HV boundary, and this signal could be readily passed on to users of the HV and LV network as well.

1.80. Any change along these lines would need to be integrated with the options we discuss below for varying CDCM charges by primary substation, or by groupings of primary substation, alongside our consideration of whether there is any case to also group primaries in assessing the EHV network. Whilst this could help to minimise the volatility of charges, the reduction in granularity may negatively impact cost reflectivity.

Consolidating the models used for EDCM to a single model

1.81. The EDCM presently contains two different methods for calculation of locational charges for customers connected at EHV or at a primary substation. Presently each DNO licensee can choose which method they apply for customers in that area. LRIC is used by eight DNO licensees and produces a nodal charge, whereas FCP is used by six licensees and produces a zonal charge based on network branches. More detail on these methodologies is provided in our Current arrangements discussion note.

1.82. We presently find it difficult to see a rationale for retaining different approaches for different areas, which are largely an artefact from historical charging reforms where a common approach was not agreed. We believe that there would be strong benefits to ensuring a harmonised model is taken forward in the future, which could help to reduce complexity and improve the transparency of the charging regime.

1.83. Whilst we recognise that there are differences in the asset mix and connectivity of the distribution network in different licensee areas, we are of the view that these differences could be accounted for in the inputs to a common model rather than through entirely different methodologies that predicate charges on a different understanding of how users drive or save costs.

1.84. Both LRIC and FCP are examples of an incremental long run approach. In considering the potential for an ultra long run approach, one of the options which we are continuing to explore is the possibility to extend the Transport model (used to calculate TNUoS charges) to the EHV network. This could be either an extension of the Transport model itself, or an analogous model for the EHV network that adheres to similar principles.

Whilst we are yet to fully consider this option, one of the potential benefits it could provide is improved alignment of network charges across the transmission and distribution network.

Locational granularity of cost models

1.85. As context for this discussion, Figure 9 provides a breakdown of the approximate number of customers and agreed import/export capacities at each voltage level of the network based on information provided by the Delivery Group.

Figure 9: Breakdown of distribution network topography, customer numbers and capacities

	Customer count	Generator count	Sum of agreed import capacities (MVA)	Sum of agreed export capacities (MVA)
Grid Supply Point (400/275kV→ 132kV)*	152	123	2,965MVA	4,075
EHV distribution network (132kV)	211	152	3,127MVA	8,434
Bulk Supply Point (132kV → 66kV or 33kV)	281	171	3,029MVA	3,785
EHV distribution network (66kV or 33kV)	1,398	1,332	2,196MVA	12,828
Primary substation (EHV → HV)	371	92	2,041MVA	521
HV distribution network (22kV)	24,104	3,514	22,975MVA	
Distribution transformer (secondary substation)	10,392	448	3,064MVA	9,824
LV distribution network (<1kV)	30,777,150	11,527	Not available	

Direct transformation from 132kV to HV

*Note that 132kV network is classified as transmission in Scotland, and therefore is not included in these figures.

Key: Distribution network (blue); Point of transformation (grey)

Extent to which greater locational granularity can be achieved

1.86. Currently, the EDCM extends to the lower voltage side of the primary substation. One possibility we have been considering is whether a nodally granular methodology such as the EDCM could be further extended into the distribution network, subject to data availability, the improvement in cost reflectivity and the proportionality of such an option.

1.87. Our initial work with the DNOs through the Delivery Group has concluded that it is not presently possible to extend a fully nodal assessment of the network down to HV using load flow modelling (as is presently done for EHV). The current EHV models include c.5,300 fully modelled primary substation sites compared to c.600,000 sites that would be required to extend this to a secondary substation level (including the HV network).

1.88. Whilst asset-based modelling to this level of granularity would be less dependent on having a fully modelled network, the lack of accurate and maintained connectivity models for the HV network across all DNOs presently leads us to believe that this approach may also be infeasible within the SCR timescales. A prerequisite for this option is accurate information on the lengths and types of circuits, and the mix of assets below each primary substation. While we continue to investigate this area further, at present it appears that this data may not be consistently available in all cases.

1.89. Our initial assessment of extending the level of granularity suggests that, whilst we recognise the value that improved network data could bring in the future, it is unlikely to be feasible to obtain the necessary missing data (within the timescales we envisage for implementing the conclusions of this SCR), given the large volume of high quality data on network assets that would have to be collected and maintained in power flow modelling software.

1.90. Whilst there are some targeted initiatives by DNOs to extend load flow modelling capabilities and network monitoring to HV on a targeted basis, these capabilities are not expected to be available across all DNOs within the RIIO-ED1 period, nor will the coverage of rollout be sufficient for charging purposes within the timescales of the SCR.

1.91. If our assessment remains unchanged following our further investigations, we do not expect it will be credible to develop and implement options for location-specific charges below a primary substation level. We therefore do not expect that forward-looking DUoS charges will be locationally granular to an individual street level, or an individual household level. We are undertaking further work with input from our Delivery Group to consider what level of granularity may be both feasible and desirable if accurate nodal (per customer) charging is not currently possible at HV and LV.

1.92. There are a number of different options for how charges could be set based on grouping primary substations according to variables that enable more locationally cost-reflective signals to be set on an average basis. These options for charging based on groupings could include:

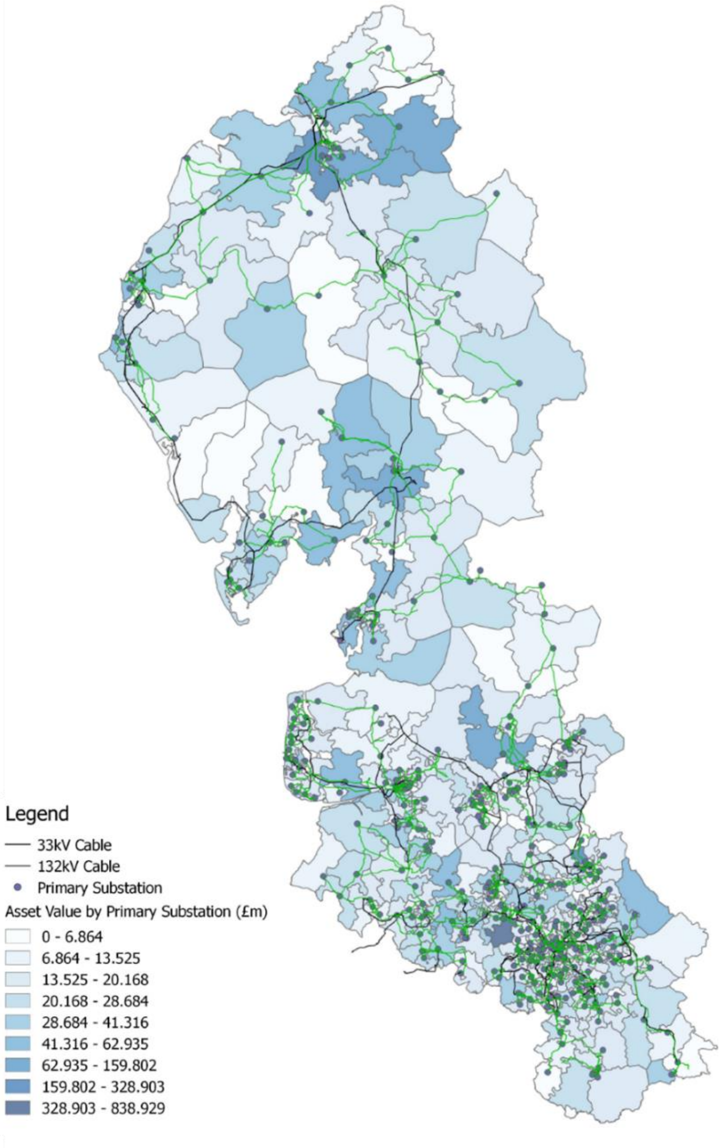
- Averaged charging across groups of electrically proximate primary substations in an area (eg clustered substations within a postcode region).
- Charging based on the classification of primary substations that capture differences in cost drivers (eg urban vs rural areas).
- Charging based on groupings of primary substations with a similar asset mix (eg the average length and/or proportion of overhead lines versus underground cables), which could possibly be inferred if actual data is not available.
- Charging based on classification of primary substations according to whether network reinforcement is driven by generation export or demand import constraints (ie generation or demand dominated areas).

1.93. Our first step in considering this has been to validate the assumption that HV and LV network costs vary significantly by location and that there could be value in signalling these cost variations to a more granular level.

1.94. Figure 10 is based on data received from Electricity North West Ltd (ENWL) and shows evidence of variation in asset values below the primary substation. ENWL are presently undertaking an exercise to improve their network connectivity models, and therefore were able to provide data on their HV network, as well as inferred data for the LV network (where asset information has been assumed and linked to substations based on geographical proximity). The cost data illustrated in this figure is based on Ofgem benchmarking data for typical asset values.

1.95. The figure shows that although HV and LV costs do appear to vary significantly, there is no clearly apparent pattern to cost variations based on geographical location or electrical connectivity, and that the costs inferred below one primary substation may not be indicative of the costs incurred below a neighbouring primary.

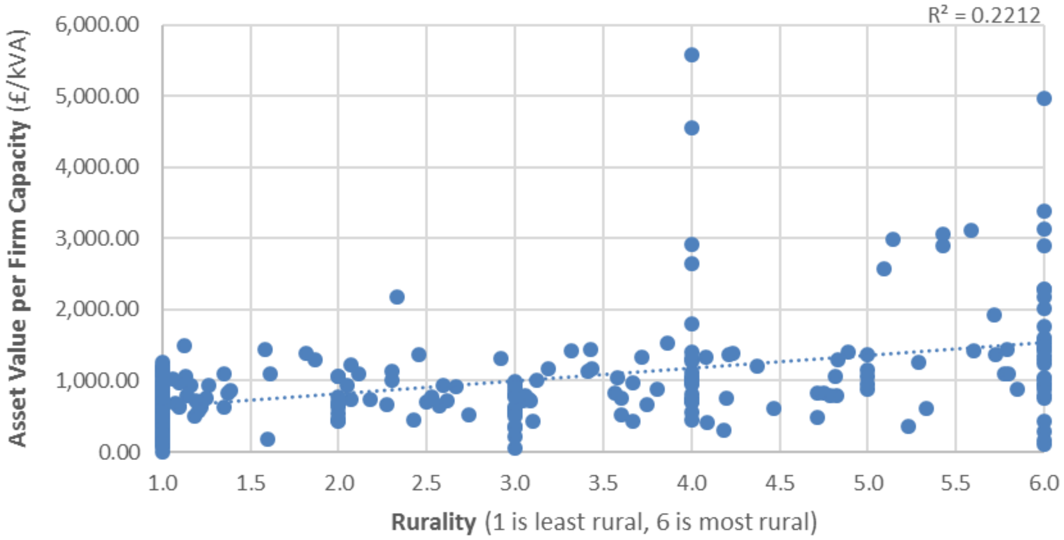
Figure 10: Map of asset value of HV and LV network below primary substation, by primary substation (source: Electricity North West Ltd network data and Ofgem cost data)



1.96. Whilst we are yet to fully explore all potential categorisations, we have conducted some early analysis of whether primary substations could be categorised according to an urban/rural classification (using Office for National Statistics data linked to primary substations). This is show in

1.97. Figure ***11*** and would seem to suggest that, although there is a weak correlation between rurality and increased costs, a simple single variable classification according to rurality is unlikely to produce a cost-reflective charge.

Figure 11: Chart of asset value of HV and LV network below primary substation divided by firm capacity of primary substation (£/MW) versus rurality of primary substation (source: Electricity North West Ltd network data, Ofgem cost data and Office for National Statistic rurality data)



1.98. A key consideration for the next phase of the work will be to consider how generation dominated areas would be treated under each of these locational granularity options (for example, whether generation could receive a charge, and demand could receive a credit), such that network users receive cost-reflective revenues.

1.99. We think that introducing generation-dominated and demand-dominated archetypes could have merit, as there is reasonable data to support such a classification at primary substation level, and this would allow clearly different cost drivers to be differentiated. We intend to gather further data on the extent to which cost drivers do vary between generation- and demand-dominated areas.

1.100. The treatment of "spare" network capacity may interact with the options for locational granularity options. If we determine that spare capacity could be reflected in a charge, this may support the case for additional granularity (because the level of spare capacity will vary across the network). In practice, we note that it is unlikely to be possible to measure spare capacity on a universal basis below primary substations. Whilst the DNOs submit information on this in their load index packs, which is based on spare capacity availability at the primary substation transformer, this may not provide meaningful information about the spare capacity of the downstream network. This implies that it would not be possible to take a moderate long-run approach to setting charges for costs below primary substation level.

1.101. We will be undertaking further work with input from the Delivery Group on the desirability of these different options from an efficiency perspective, based on the extent to which they could support improved cost reflectivity. Additionally, this analysis has not included the costs of non-electrical assets, such as civils (eg undergrounding), repairs (eg digging up roads), and differing maintenance costs (eg tree-cutting).

1.102. One of the main barriers to enhanced locational granularity, particularly for smaller users (but also true for large users) is the public and political acceptability of applying different costs to different users. To some extent, there is already some differentiation between the charges in different DNO regions. This barrier will be considered further in the Small Users working paper.

Section 5: Summary of our preliminary views

1.103. Our preliminary view is that distribution charging cost models should continue to be based around an LRMC approach. SRMC approaches may be possible in the future however our analysis so far suggests that there are significant feasibility challenges associated with at-scale distribution level implementation. Seeking to set SMRC charges administratively would not facilitate competitive price discovery and therefore we believe this would be better delivered through a market-based approach such as LMP. We do not believe such an approach is feasible at distribution-level in the near term and continue to consider it out of the scope of this SCR.

1.104. We are continuing to consider the merits of the different options for the estimation of LRMC. We think there is a reasonable case for including replacement costs within the charge in addition to reinforcement costs, and possibly other costs closely correlated with network development. These are a significant DNO expense and users' continued use of the network means that these costs need to be incurred. Including replacement costs can conceptually work under either an incremental long run approach (that considers spare capacity availability but may be more volatile) or an ultra long run marginal cost approach (that does not but may be more stable). However, we recognise that, in practice, it is unlikely that significant parts of the network will be replaced with smaller assets, particularly in a world of electrification of heat and transport.

1.105. We note that there are presently inconsistencies in how different costs are treated by the different DUoS methodologies. This creates potential distortions in how costs are signalled at different voltage levels. We are of the view that changes to the locational granularity of charges should attempt to provide cost-reflective signals consistently across voltage levels where possible, avoiding undue cliff edges. One option to do this could be to have charges from the EDCM pass down to lower voltage customers, rather than using a separate model as presently. This would mean charges for users connected to the HV or LV network would be calculated in the same way as users connected to the EHV for their use of the EHV network.

1.106. We have also considered whether the current approach of charging users based on their impact on the upstream network continues to be fit for purpose. We think that if charges can reflect the differences in cost drivers between generation-dominated and demand-dominated areas of the network, then the present system of charges and credits (based on upstream costs only) can provide the right signals about how costs vary relatively between different locations. The present system also ensures that users who can provide value to the network can access that value readily through a system of credits. An approach that considers both upstream and downstream costs, but only involves charges, could bring benefits in terms of ensuring charges reflect absolute costs, but it is not clear that such a substantial change to charging arrangements would be justified. In particular, it would make it harder for those who can help mitigate network costs to access the value they can provide, as they would no longer receive credits.

Annex – Additional detailed design options for distribution locational cost models

How should the network be represented?

1. It is necessary to have an appropriate representation of the network in order to determine how network users in a given location are contributing to or helping offset future network costs. We believe the high level options for this network modelling are:

   - **Load flow modelling –** Also referred to as a 'power flow' modelling, this is where a simulated representation of the network is created to show how power will flow across the network at peak times. If needed for the chosen methodology, this can also be used to estimate where and when reinforcement might be needed.
   - **Asset-based modelling –** This is where a model is created based on the mix of assets and/or a measure of the amount of network (eg distance of cables and/or overhead lines) and assumptions about how power will flow over those assets.
   - **Asset based modelling with network monitoring –** This is where an asset-based model could be supplemented with either real-time network monitoring based on DNO SCADA or based on periodic review of substation load indices. It can act as a proxy for load flow modelling to allow better informed judgements than a pure asset-based model about how power is flowing and, potentially, on how close is the need for reinforcement or replacement of assets. Since this approach is informed by real metered data, it could potentially be more accurate than load flow modelling assumptions.

2. Load flow models of the network, using a fully nodal representation of the network which includes data on each network element, have the potential advantage that they can produce a very accurate picture of how different users are contributing to flows across the network. This can then be used to attribute costs to users based on which assets they are flowing over (or offsetting the dominant flows on, in the case of credits). They can be used for both ultra and incremental long run approaches, as they can either be agnostic about levels of spare capacity on the network or use load growth forecasts to model when reinforcement will be needed.

3. However, load flow models are very data intensive. This means that load flow modelling is not currently possible for voltages below primary substation level as DNOs do not have sufficient data to allow this. We expect this to improve over time but not in time to be feasible for the implementation timelines we are aiming for with this SCR. Additionally, the quality of load flow model outputs relies on the quality of input data, including assumptions about generation and demand, and ensuring that the model assesses the network at the right times (ie 'peak flow' – which might be different across the network at different times).

4. One important consideration is what level of detail is warranted for a charging model, with an important consideration being that transparency of the model has significant value for users in helping them predict their charges. This is a criticism made of the load flow modelling approach used for EDCM charging – the models contain confidential customer data which mean that DNOs are not able to make their load flow models public, resulting in opaque pricing.

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 (eg operation and maintenance costs). More simplified power flow analysis can be used to assess the amount that each user group makes use of particular assets. For example, the CDCM identifies the contribution to peak demand made by each user group as this is deemed to be a key underlying driver of costs.

6. Such approaches are typically used when detailed data on where power flows is not available, or overly onerous to collect/process. They can vary in the level of granularity – the CDCM currently involves one asset model per DNO region but it is possible that this could be split such that different asset models are constructed to represent different types of network. However, they may not be as accurate in situations where it is not clear what is driving peak flows and the direction of them, and they cannot be used to inform judgements about when reinforcement or replacement will be needed.

7. Asset based modelling supplemented with network monitoring information can be seen as a hybrid between the two basic approaches. It could potentially be used to help derive which ways dominant flows are at peak in different network areas or proxy for when reinforcement might be needed (for example using load indices). It could also potentially be used as a proxy for when asset replacement might be needed (using asset health indices). However, this is dependent on the coverage of those indices – for example, substation loading indices (which DNOs already report on[6]) can tell information about how close to capacity they are but do not tell you about the loading of circuits connected to them. We intend to consider further the extent to which network monitoring information can supplements asset based modelling to support the different cost model and locational granularity options. In addition to being less data reliant than load flow modelling, such an approach could also have benefits in terms of allowing the forward-looking charge to be derived in a more transparent manner than the current approach at EDCM.

What modelling approach should be used?

8. A further design decision is how to calculate the marginal cost of an additional unit of demand or generation on the network. Different options apply depending on the choice of ultra versus incremental long run marginal cost approach, and may rely on certain approaches for representing and assessing the network (eg a load flow assessment). We discuss which methodologies are used currently in network charging in GB in our Current arrangements note.

9. We have identified two broad options for an incremental LRMC approach:

- **Average Incremental Cost.** The LRMC is derived by dividing the additional cost of forecast network build by the forecast size of the demand increment. The 'FCP' methodology used under the EDCM is similar to this approach.
- **Perturbation-based Marginal Cost.** The LRMC is derived by subtracting the cost of a best forecast network build scenario from the cost of that scenario plus a small, permanent increment of demand or generation. The 'LRIC' methodology currently used under the EDCM is similar to this approach.

[6] For each 132kV and 33kV substation and 33kV substation group this gives details of loading, capacity, limiting constraint and season of constraint.

10. We have identified two broad options for an ultra LRMC approach:

- **Standalone Approach.** The LRMC is derived from the costs of meeting a small increment of demand or generation, without forecasting the future. The Transport model methodology currently used to determine TNUoS charges is an example of the standalone method.
- **Total Service Long Run Incremental Cost.** The LRMC is derived by dividing the full cost of a hypothetical optimised network by the capacity served. CDCM is an example of this approach.

11. We view this question as being highly linked to the question of whether to pursue an incremental or long run marginal cost approach.

12. The average incremental cost and permutation-based marginal cost approaches are different ways to implement an incremental long run based approach. While we have not considered the relative pros and cons of these methodologies in detail at this stage, our initial analysis suggests that the perturbation-based marginal cost approach may have some advantages in terms of more clearly identifying the cost of a marginal addition to the network, and in not relying as heavily on forecasts of future demand and generation on different nodes on the network.

13. The standalone approach and the total service long run incremental cost methodologies are different ways to implement an ultra long run based approach. Again, we have not considered them in detail at this stage but our initial thinking is that the key difference is that the standalone approach implies use of load flow modelling based on a model of the existing network, whereas the total service long run incremental cost approach implies use of asset-based modelling. It therefore seems that the choice between these methodologies will follow from the choice between the network modelling approaches.

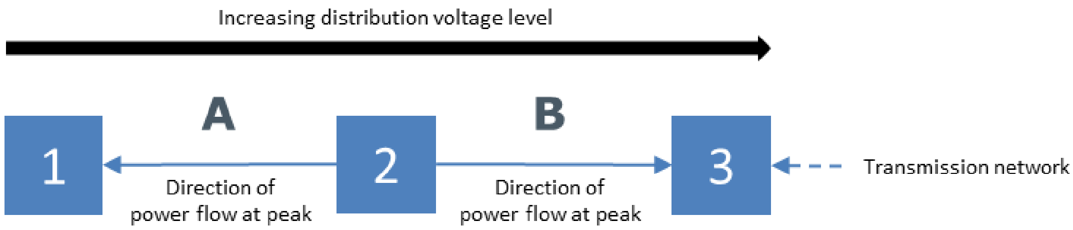
DNO costs disaggregated by category

Figure 12: Total DNO costs for RIIO-1 period sourced from Regulatory Reporting Pack submissions (2012/13 prices)

			Total	Per DNO	Per DNO Per Year	Proportion
Load related	Connections within the price control	£'m	362.3	25.9	3.2	1.1%
	Reinforcement (Primary Network)	£'m	965.1	68.9	8.6	2.9%
	Reinforcement (Secondary Network)	£'m	519.6	37.1	4.6	1.6%
	Fault Level Reinforcement	£'m	112.9	8.1	1.0	0.3%
	New Transmission Capacity Charges	£'m	98.3	7.0	0.9	0.3%
	Total load related costs	**£'m**	**2,058.2**	**147.0**	**18.4**	**6.3%**
Non-load capex	Diversions (Excluding Rail Electrification)	£'m	601.4	43.0	5.4	1.8%
	Diversions (Rail Electrification)	£'m	19.7	1.4	0.2	0.1%
	Asset Replacement	£'m	4,258.4	304.2	38.0	13.0%
	Refurbishment no SDI	£'m	349.5	25.0	3.1	1.1%
	Refurbishment SDI	£'m	232.6	16.6	2.1	0.7%
	Civil Works Condition Driven	£'m	363.4	26.0	3.2	1.1%
	Operational IT and telecoms	£'m	446.9	31.9	4.0	1.4%
	Blackstart	£'m	65.5	4.7	0.6	0.2%
	BT21CN	£'m	71.0	5.1	0.6	0.2%
	Legal & Safety	£'m	261.3	18.7	2.3	0.8%
	QoS & North of Scotland Resilience	£'m	197.3	14.1	1.8	0.6%
	Flood Mitigation	£'m	92.3	6.6	0.8	0.3%
	Physical Security	£'m	3.5	0.3	0.0	0.0%
	Rising and Lateral Mains	£'m	151.2	10.8	1.3	0.5%
	Overhead Line Clearances	£'m	350.8	25.1	3.1	1.1%
	Worst Served Customers	£'m	17.6	1.3	0.2	0.1%
	Visual Amenity	£'m	56.9	4.1	0.5	0.2%
	Losses	£'m	30.9	2.2	0.3	0.1%
	Environmental Reporting	£'m	63.7	4.5	0.6	0.2%
	Total non-load capex (excluding Non-op capex)	**£'m**	**7,633.9**	**545.3**	**68.2**	**23.3%**
Non-op Capex	IT and Telecoms (Non-Op)	£'m	466.4	33.3	4.2	1.4%
	Property (Non-Op)	£'m	142.8	10.2	1.3	0.4%
	Vehicles and Transport (Non-Op)	£'m	233.8	16.7	2.1	0.7%
	Small Tools and Equipment	£'m	173.9	12.4	1.6	0.5%
	Total non-op capex	**£'m**	**1,016.9**	**72.6**	**9.1**	**3.1%**
HVP	High Value Projects DPCR5	£'m	72.5	5.2	0.6	0.2%
	High Value Projects RIIO-ED1	£'m	95.8	6.8	0.9	0.3%
	Total high value projects	**£'m**	**168.3**	**12.0**	**1.5**	**0.5%**
Moorside	Moorside	£'m	-	-	-	0.0%
	Total Moorside	**£'m**	**-**	**-**	**-**	**0.0%**
Network Operating Costs	Faults	£'m	2,349.6	167.8	21.0	7.2%
	Severe Weather 1 in 20	£'m	68.2	4.9	0.6	0.2%
	ONIs	£'m	644.3	46.0	5.8	2.0%
	Tree Cutting	£'m	890.8	63.6	8.0	2.7%
	Inspections	£'m	262.5	18.8	2.3	0.8%
	Repair and Maintenance	£'m	713.8	51.0	6.4	2.2%
	Dismantlement	£'m	13.9	1.0	0.1	0.0%
	Remote Generation Opex	£'m	27.7	2.0	0.2	0.1%
	Substation Electricity	£'m	147.7	10.6	1.3	0.5%
	Smart Metering Roll Out	£'m	207.9	14.8	1.9	0.6%
	Network Operating Costs	**£'m**	**5,326.4**	**380.5**	**47.6**	**16.3%**
Closely associated Indirects	Core CAI	£'m	4,685.6	334.7	41.8	14.3%
	Wayleaves	£'m	499.3	35.7	4.5	1.5%
	Operational Training (CAI)	£'m	529.7	37.8	4.7	1.6%
	Vehicles and Transport (CAI)	£'m	568.1	40.6	5.1	1.7%
	Closely Associated Indirects	**£'m**	**6,282.7**	**448.8**	**56.1**	**19.2%**
Business Support Costs	Core BS	£'m	1,316.6	94.0	11.8	4.0%
	IT& Telecoms (Business Support)	£'m	1,018.4	72.7	9.1	3.1%
	Property Mgt	£'m	432.5	30.9	3.9	1.3%
	Total Business Support Costs	**£'m**	**2,767.5**	**197.7**	**24.7**	**8.5%**
Other costs within Price Control	Atypicals Non Sev Weather	£'m	332.7	23.8	3.0	1.0%
	Atypicals Non Sev Weather (excluded from Totex)	£'m	5.0	0.4	0.0	0.0%
	Network Innovation Allowance (NIA)	£'m	111.9	8.0	1.0	0.3%
	Network Innovation Competition (NIC)	£'m	67.9	4.9	0.6	0.2%
	IFI & Low Carbon Network Fund	£'m	34.1	2.4	0.3	0.1%
	Other costs within Price Control	**£'m**	**551.6**	**39.4**	**4.9**	**1.7%**
	Total Costs within Price Control	**£'m**	**25,805.6**	**1,843.3**	**230.4**	**78.8%**
Costs outside Price Control	Connection costs outside of the price control	£'m	- 1,238.8	- 88.5	- 11.1	-3.8%
	Other cost outside of the price control	£'m	1,301.1	92.9	11.6	4.0%
	Total Costs outside Price Control	**£'m**	**62.4**	**4.5**	**0.6**	**0.2%**
Total Non Activity Based costs		**£'m**	**6,870.6**	**490.8**	**61.3**	**21.0%**
	Total DNO	**£'m**	32,738.5	2,338.5	292.3	100.0%

Who should receive the signal?

14. The examples below set out four different conceptual approaches to how charges could be levied on network users, accounting for factors such as; whether both charges and credits are issued, whether charges are for upstream network voltages only or also include downstream network voltages, and the treatment of areas where generation is driving network costs. The example is based on a three node distribution network.



Example 1 – Status quo arrangements (for comparison)

Description	Circuit	Additional Increment	Node 1	Node 2	Node 3
• Upstream only • Both charges and credits • Demand assumed to drive costs	A	Demand	charge	-	-
		Generation	credit	-	-
	B	Demand	charge	charge	-
		Generation	credit	credit	-

15. In this example, the table has been completed based on status quo arrangements. The cells highlighted in red indicate a situation where additional generation connecting to nodes 1 or 2 and exporting at peak would drive network development costs, but (under current arrangements) would continue to receive a credit. Conversely, demand would be mitigating peak flows but would be paying a charge. The current charging regime is based around considering users' impact on upstream network voltages only, therefore no charging signals are sent for node 3 under DUoS charges (they would be exposed to TNUoS charges alongside nodes 1 and 2).

Example 2 – Introduction of generation dominated areas

Description	Circuit	Additional Increment	Node 1	Node 2	Node 3
• Upstream only • Both charges and credits • Demand assumed to drive costs	A	Demand	charge	-	-
		Generation	credit	-	-
	B	Demand	credit	credit	-
		Generation	charge	charge	-

16. In this example, the arrangements have been amended to introduce the concept of generation-dominated areas (GDAs). In this example, circuit B is designated as generation dominated because it is export constrained. This means that additional generation at peak would drive network development costs rather than offset these costs.

17. In this scenario, credits and charges have been reversed for the cells highlighted in example 1, which would appear to rectify the non-cost-reflective treatment of generation that is located in GDAs – generation connecting at either node 1 or 2 will now face a charge to reflect they are contributing to peak flows on circuit B.

18. Under these arrangements, demand locating at node 3 would also be contributing to peak loads on circuit B but would face no charge (highlighted in yellow). This means the

charges would not be absolutely cost-reflective of the cost they are having on the system. However, they would still face an accurate relative cost-reflective signal – that using the network at node 3 is relatively more expensive than using it at node 2.

19. We believe that this set of arrangements could have merit because it ensures that generation and demand are treated equally and oppositely with respect to signals at all times. This can support onsite generation (located with demand) being treated equivalently to standalone generation.

Example 3 – Upstream and downstream charging (credits and charges)

Description	Circuit	Additional Increment	Node 1	Node 2	Node 3
• Upstream only • Both charges and credits • Demand assumed to drive costs	A	Demand	charge	credit	credit
		Generation	credit	charge	charge
	B	Demand	credit	credit	charge
		Generation	charge	charge	credit

20. In this example, the table has been completed on the basis of a charging regime under which all network users are issued both credits and charges for their impact on both upstream and downstream voltages. We do not presently believe that this set of arrangements would provide a cost-reflective signal to network users and this example is included to explain our reasoning.

21. In this scenario, we consider that the signals for users in the cells highlighted in red do not reflect how users can exacerbate or alleviate network flows, and so deviates from cost reflectivity. Demand at node 1 will still need to be served in these cases; additional demand at nodes 2 or 3 does not mitigate the needs for flows over circuit A. Conversely, additional generation at those nodes would not increase flows over circuit A. Similar logic applies to the charges for circuit B for those connected at node 3.

22. We note also that such a model of credits and charges could introduce potential for instances of "double signalling" through both charge avoidance and credit eligibility. For example, demand that chose to locate at node 2 rather than node 1 would both avoid a charge for its impact on circuit A and also receive a credit for its impact on circuit A (ie the difference in charging treatment will potentially double the change in the value they can bring in reducing network costs). This would appear to breach the principles of cost-reflective charging, unless the magnitude of the charge could be adjusted accordingly in a manner which is cost-reflective for all charge recipients.

Example 4 – Upstream and downstream charging (charges only)

Description	Circuit	Additional Increment	Node 1	Node 2	Node 3
• Upstream only • Both charges and credits • Demand assumed to drive costs	A	Demand	charge	-	-
		Generation	-	charge	charge
	B	Demand	-	-	charge
		Generation	charge	charge	-

23. In our final example, the table has been completed on the basis of a system where all network users are issued only charges for their impact on both the upstream and downstream network. Under this approach, no credits are issued.

24. We believe that this model would be consistent with the principles of cost reflectivity. Whilst no credits are issued, network users do still receive a locational signal due to the absolute difference in their network charge. For example, demand choosing to locate at

node 1 would face a charge for circuit A, whereas demand choosing to locate at node 2 could avoid this charge. The magnitude of charges could still be set cost-reflectively to ensure that accurate signals about the differences in costs/benefits between locations are sent.

25. One feature of this approach would be a move to absolute network charging based on cost/benefit incurred. Whilst this option does appear to work conceptually and would enable absolute charging signals, it would entail a significant departure from status quo arrangements and the case to do this would have to be made proportionate to the benefit that could be delivered by such a significant change. We have particular questions around whether this approach would allow users who can help mitigate future network costs to readily access the value they provide, and whether it could introduce distortions in treatment of different types of user if charges are not symmetric (eg between onsite generation and standalone generation).