Charge design options for distribution and transmission charges – discussion note

Summary

This note provides an overview and initial assessment of the different options for how charges are designed, ie choices around the structure of tariffs.

We have identified five basic options for the design of **distribution use of system (DUoS) charges:**

1. **Agreed capacity** – charges based on users' agreed access rights could provide DNOs with greater certainty about customers' maximum possible contribution to the system peak, though we need to do further work to establish the extent to which this would filter through to how DNOs plan their networks. We also need to consider the administrative burden to agree and maintain capacities for all customers

2. **Actual capacity** – charges based on users' maximum recorded capacity requirement may more closely align with the drivers of network costs, although this would be dependent on the granularity of charges (ie the alignment between a customer's peak and local assets) and the factors the DNOs consider when planning their networks. In practice, we think this option could be similar to a volumetric time-of-use option and we have not yet identified any clear merits of actual capacity in comparison

3. **Volumetric time-of-use** – while we do not think flat volumetric charges (with the same charge for consumption at any time during the year) reflect key drivers of network costs, we do think that volume-based charges with high charge periods that vary by time of day and potentially seasons could reasonably reflect network cost drivers, and may have merit in being relatively easy to understand.

4. **Dynamic charging** – which could involve high charge periods only being set shortly in advance, when peak network conditions are forecast, may not be feasible by 2023 due to the extent of the network monitoring equipment that would need to be installed and connectivity identified to support it. However, we will need to undertake further work to identify whether arrangements could be implemented to allow for dynamic charging in the future.

5. **Critical Peak Rebates** – which could involve paying rebates to users who reduce their usage during peak times may also be infeasible, due to similar challenges around monitoring as the dynamic charging options and difficulty in establishing a method to determine the baseline by which any reduction would be measured. However, we will continue to consider whether there are any simpler variants that may have value.

For **transmission network use of system (TNUoS) demand charges** for large users, our preliminary view is that the main options are between moving to a different form of dynamic charging than the current Triad approach (with high charging periods notified in advance) or moving to an agreed capacity approach. We will consider applying volumetric time-of-use or actual capacity TNUoS charges (among other options) for small users.

We also consider a number of issues that cut across different options, such as whether introducing more seasonality and locational variation into when high charge periods could have merit.

This discussion note is set out as follows:

- Section 1 – we set out the charging design options that we are considering for DUoS charges
- Section 2 – we give initial consideration to the overarching question of whether demand and generation should be treated as equal and opposite
- Section 3 – we discuss our initial assessment of the individual charging design options and their application to DUoS charges
- Section 4 – we discuss our initial assessment of the individual charging design options and their application to TNUoS demand charges
- Section 5 – we discuss our initial thinking on cross-cutting issues relating to more than one DUoS charging design option
- Section 6 – we discuss our initial thinking on cross-cutting issues that relate to both DUoS and TNUoS charging design options
- Section 7 - we set out our preliminary views around the charging design options and how they apply to DUoS and TNUoS charges and cross-cutting issues.

5.1. Charging design refers to the choices around the structure of tariffs, such as between volumetric or capacity based charges, whether charges should include seasonal differences and whether the same design should apply to both transmission and distribution and generation and demand customers. Charging design will also take into consideration the locational granularity that charges should be calculated and applied at, as described in the Distribution Locational Charging Models note.

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

5.3. Our Access and Forward Looking Charges Significant Code Review (Access SCR) concerns the charging design for forward-looking charges. Forward-looking charges are those that signal the forward-looking cost to the network which the network companies seek to signal to the customer (through their supplier) to elicit a response to that price signal. This contrasts with the charging design for residual charges, which recover the portion of total revenue not recovered via forward-looking charges and do not seek to elicit a response. The charging design of residual charges is being reviewed through the Targeted Charging Review (TCR).[1]

5.4. In our December launch statement for the Access SCR, we included a wide-ranging review of DUoS charging within the scope of the review. We also said we would undertake a focused review of TNUoS charging, [2],[3] which would look at:

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[1] We have separate concerns about the scope for reduced demand during Triad periods to reduce users' residual charges, which can distort behaviours while not leading to network savings. These issues are being addressed through our Targeted Charging Review SCR: https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-minded-decision-and-draft-impact-assessment

[2] We are not reviewing the charging design of TNUoS charges for transmission connected generation users, as we did this relatively recently (through Project Transmit which was implemented in April 2016) and our analysis pre-SCR launch (including work carried out by Baringa) did not identify strong need for further significant changes

[3] We will cover TNUoS charges for distributed generation users, the Reference Node and the application of TNUoS demand charges to small users (with a focus on domestic and small business demand users)

- demand charging – the current approach creates uncertainty, due to the unpredictable nature of the charges, and may not be cost-reflective
- distributed generation – aligning charges across different sizes and types of users could reduce distortions, ensure a level playing field and support more efficient investment decisions
- the Reference Node – we have identified this as a lower priority but indicated that we would consider it, if changes are required as a consequence of reviewing other matters or if there is evidence that it is a significant cause of a distortion between types of users.

5.5. We have identified five basic charging design options, which are summarised in this discussion note alongside some cross-cutting issues that may impact on many or all the options and our preliminary views, where we have reached one. In addition to our five separate options, there may also be merit in combining them into hybrid options, such as combining agreed capacity with time-of-use charging options (similar to under the current arrangements for larger users). We have not considered these in detail at this stage but may do going forward if our analysis suggests they could be merited. Finally, we will also consider which charge design fits best with our emerging position on access rights and flexibility.

Section 1. DUoS charging options under consideration

5.6. We have engaged with both the Delivery and Challenge Groups on the development of our future charging design options. We also reviewed international case studies on network charging and these have informed development of our charging design options. The case studies were summarised in an annex to a note[4] we have published on how our charging design options might apply to DUoS charges.

5.7. We have identified five basic options for network charges that could be applied to demand users (or potentially credits for demand users in some instances, such as in a generation dominated area). These charges are in many cases incurred by suppliers, rather than end users, and it is up to the supplier whether and how they pass the costs on to different customer types as illustrated in the table below.

[4] http://www.chargingfutures.com/media/1329/charging-design-initial-options-listing-final-version-publishable_-002.pdf

Table 1: comparison between different static charging design options

Actual capacity	• Customers are charged in £/kW (or measured in other similar ways), based on their actual maximum capacity on the network measured on an ex post basis. • Customers might only face a charge for their maximum actual capacity during a specified peak period that reflects the times the network is congested. • Alternatively, customers could face different rates for capacity measured during different time bands. The capacity measurement is reset at specific intervals (eg monthly, quarterly, annually).
Volumetric time-of-use	• Different unit rates (in £/kWh) are assigned to set periods of the day called time bands, which reflect the probability that the network will be congested during that period. • Customers are charged for the energy they consume during each time band. As part of our assessment, we will consider whether this should be on a gross or net basis.
Agreed capacity	• Customers (or suppliers on their behalf) would need to agree with their DNO the maximum capacity they require on the network on an ex ante basis • Customers would pay a £/kW charge (or measured in other similar ways, such as £/kVA), based on the level of agreed capacity.
Dynamic pricing	• Under Critical Peak Pricing, customers would be charged a high charge during periods when the network is actually congested and a low or no forward-looking charge for the rest (and vast majority) of the year. The high price periods would be determined and notified in advance (eg day ahead). • Typically, under Critical Peak Pricing the rate, but not the period, is known before the commencement of the year, so the period is the dynamically set element. • Alternatively, under real-time pricing, the rate is dynamically determined and may change for each half hour period of the year and notified to customers a short period in advance.
Peak rebates	• This is similar to a Critical Peak Pricing option, except that, instead of being charged high prices during a critical peak day, customers would receive rebates for reducing their consumption or capacity during the peak periods.

5.8. There are a number of alternatives for each element that makes up the five basic options, resulting in a large number of variants. Some examples are:

- whether to include seasonal variation in volumetric time-of-use charges
- the basis of agreed capacity – should it be negotiated individually, deemed for some users or chosen from a menu,[5] and how this fits with access rights choices
- the number of peak periods under a dynamic charging option.

[5] Under a 'deemed' option, the DNO or supplier would choose the capacity, while under a 'menu' option, there would be standard levels of capacity the customer could choose from

5.9. We developed a draft note on these basic options and the variants of these options and sought feedback from the Delivery Group and Challenge Group. Following our consideration of the Delivery Group's and Challenge Group's feedback, we published an updated note on the Charging Futures website[6] describing the basic options and variants in more detail.

5.10. The options described above all assume that a supplier will be individually billed for each customer, based on their actual consumption or actual or agreed capacity. However, it is also possible to introduce charging arrangements under which suppliers are billed, based on the aggregated consumption of all their customers in a specific segment (e.g. domestic or LV connected).[7]

5.11. In general, we believe that charging should aim to provide equivalent signals to different kinds of user, to avoid introducing distortions. For example, it is important to consider whether charges provide standalone generators with similar signals as demand users installing onsite generation. At the same time, there may be different charge design considerations for different types of user. We consider the issue of whether there should be differences between demand and generation customers in the next section.

Section 2. Should demand and generation be treated as equal and opposite?

5.12. Under our Access SCR, we are also reviewing the charging arrangements for distribution connected generation, which currently receives credits for export. This is informed by a wider question about whether demand and generation should be treated as equal and opposite. Key considerations include whether:

- Both demand and generation have the same impact on costs
- A symmetric approach is appropriate for all charging arrangements, or whether there is some justification for differences in treatment
- The application should be the same for all demand or all generation customers
- The impact on the wider regulatory framework.

5.13. In our Distribution Locational Charging Models note, we considered in detail whether generation and demand contribute to network costs in the same way, where they are the main driver of network constraints and peak usage. Our preliminary view was that both demand and generation are likely to have a similar impact on the network with respect to network constraints. For example, in an area where peak flows relate to generation output, rather than demand (known as a 'generation dominated area'), then an increase in demand at times of generation-led peaks would help avoid or manage constraints. In such instances, charging the customer for demand would send an inefficient signal, as it would incentivise the customer to reduce their demand, thereby increasing the risk of a generation driven constraint. It would also mean that demand customers may consider installing onsite generation or storage to reduce their charges, but this would act to increase rather than mitigate constraints. This suggests that, not only would a symmetric approach be more cost-reflective, but it would also incentivise efficient use of the network.

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[6] http://www.chargingfutures.com/
[7] At the time we published our note, we were not sure whether it would be possible to apply aggregate billing to all our options. Following conversations with the DNOs and some suppliers, we consider it is likely to be possible.

We recognise, that there are reasons why it may not be appropriate or practical to apply the same approach to generation and demand in all circumstances.

5.14. One example of this is the degree to which generation and demand influence network costs symmetrically. An example of this is on fault level constraints, which are generally caused by some generation technologies, rather than by demand, as discussed in the User Segmentation section of the Cost Drivers subgroup's report.[8] For costs like this, it may not be cost-reflective for them to be allocated to generation and demand users (and vice versa for demand only costs). We will need to do further work to determine the materiality of such costs that can be identified as being driven by generation or demand, as it may not be consistent with our third guiding principle to include additional complexity in our cost model for all cost categories.

5.15. Even where a decision is made that it is right that the underlying cost model should be the same in how it allocates costs to generation and demand customers, it may not be the case that all charge design options are equally appropriate for all types of user. We discuss this further in the Distribution Locational Charging Models note. We also note that, even where the underlying cost models allocate costs symmetrically, it may not be appropriate to reflect costs in the same way for all customers, where different customer groups drive different network costs. For example, within the TNUoS application of agreed capacity for larger generators, there is an adjustment for generators' technology type and annual load factor in calculating their wider locational tariffs. We will consider whether it is more cost-reflective to apply a similar approach to DUoS generation charges and will also consider if there are differences between types of demand customers that should also be reflected in the charging design. We will consider further whether demand and generation should be treated as equal and opposite, as we have greater clarity around the options that will be included in our shortlist, including firming up our views on the issues considered in the remainder of this chapter.

5.16. In order to treat generation and demand as equal and opposite, as discussed above, the key cost driver is whether the area is generation or demand dominated. An illustration of how charges and credits could be treated symmetrically is described below for a volumetric time-of-use charging design, in a generation dominated area, the allocation of charges and credits would be:

- Demand customers would receive a credit for their consumption generation-led peak times
- Generation customers would face charges for their output during generation-led peak times.

5.17. This example would be an extension of the current charging arrangements to recognise that either generation or demand customers could take an action that has a benefit or drives costs on the network. We will consider the issue of equal and opposite charges and credits further, as part of our treatment of generation and demand being equal and opposite, but note that the appropriate policy position may be influenced by the charging design, access rights and cost model chosen. Some examples of challenges include:

- Under an agreed capacity approach, where customers pay for their maximum level of capacity on the network and can use as much as they want within this limit (note this is under a firm access right), on what basis would credits be provided? If it was decided

[8] http://www.chargingfutures.com/media/1344/scr-cost-driver-consolidated-report_v21.pdf

that, in a demand dominated area a generator receives a credit for their agreed capacity (or vice versa in a generation dominated area), it is reasonable to expect that this would incentivise the generator to oversize their capacity to increase the credit. One option could be that credits are calculated or 'trued up' to reflect actual capacity, but we will need to consider the implications in more detail.

- Under a credit-based charging design, where a customer chooses to have a flexible connection in order to be connected more quickly, we will need to consider how to ensure the charging arrangements do not result in customers receiving a double benefit, which would not be cost-reflective. We consider the linkages between charging design and access rights choices further in our Links Between Options for Reform note.

Section 3. Our preliminary considerations – application of individual basic options to DUoS charging design

5.18. In the following section, we set out our preliminary consideration of the five basic charging options and how they could apply to DUoS charges. We consider their suitability for TNUoS charges in Section 5.

Static charging options: actual capacity, agreed capacity and time-of-use volumetric options

5.19. In our charging design note, we set out three different static charging options – time-of-use volumetric, actual capacity[9] or agreed capacity charges. Each of these options have advantages and disadvantages, which we summarise in Table 2 below.

Table 2: comparison between different static charging design options

Design option	Advantage	Disadvantage
Time-of-use volumetric *Customers are charged for their actual consumption during different time bands*	• Incentivises customers to reduce peak usage on an ongoing basis • Static time-of-use is the current approach and so is easier for customers to understand • Time bands and charges set in advance are more transparent and predicable, enabling customers to more easily identify when they need to change their behaviour • Customers only face charges relating to their actual behaviour	• Static time-of-use periods may not reflect actual peak periods, resulting in inefficient network usage • Because the time bands are set in advance, they may over-reward flexibility when not required and under-reward during peak periods • May create a 'cliff edge' where consumption shifts in response to price signals, but results in a new peak period being created at the time the peak unit rate ends – could particularly be a challenge when smart devices are

[9] Note that, rather than instantaneous demand, this could be average maximum demand for some users because, smart meters can only record average maximum demand.

		ubiquitous and can be automated to respond to price signals[10]
Actual capacity *Customers are charged for their actual capacity measured during a daily peak period or on a time-of-use basis*	• If network costs are driven by system peak capacity, customers only face charges for the maximum contribution they have made during the system peak (and during the other time bands, if using a time-of-use approach) • Customers only face charges relating to their actual behaviour, rather than incurring costs for capacity they do not actually require	• For small users, it may be more difficult to understand the concept of capacity than volumetric charging • Customers do not have an incentive to manage their usage, provided they stay below the maximum demand recorded in the relevant period. This may make diversity assumptions more difficult • There may be limited difference in customer response between this and ToU volumetric, where time bands are also applied to actual capacity
Agreed capacity *Customers are charged, based on capacity they have agreed with their DNO (this could have a time-of-use element)*	• If network costs are driven by system peak capacity, customers face charges that reflect their maximum possible contribution to the system peak • As the network is sized for peak capacity (adjusted for diversity assumptions), provides greater certainty of customer usage for network companies • Reduces volatility of charges	• Provides limited incentive for customers to reduce their peak usage below their agreed capacity, as they still have to pay for the full capacity[11] • May not align with how the DNOs (or TOs) plan their networks, which could mean charges are not cost-reflective • May be difficult to agree capacities with smaller users and identify changes in their usage over time (e.g. buying an EV or solar panels)

5.20. In addition to the attributes set out above, there is a clear link between capacity based charges and the options discussed in our Access Right Options note. Defined access rights and agreed capacity charges complement each other – if we decide to implement defined access rights for some, or all, customers, then this would fit well with charging that is based on the capacity they have reserved on the distribution networks. We will need to assess how charges could be designed to reflect different access right options and what the appropriate consequences are if a user exceeds their capacity limit as identified through the

[10] See page 11 of this report for an example of this occurring in South Australia, where a new high demand period has been created between 11pm and 11:05pm: https://www.aer.gov.au/system/files/SAPN%20-%2020.34%20PUBLIC%20-%20SAPN%20Flexible%20Load%20Strategy.pdf
[11] Note that this issue may be partly addressed through wholesale market signals, where they are aligned with network charging signals. However, the issue may still exist, particularly where those signals are not aligned.

DNOs’ monitoring and enforcement arrangements (eg through exceedance charges or physical curtailment). The links between access rights and charging design are discussed further in our Links Between Options for Reform note.

5.21. We are also mindful of the fact that a long run marginal cost[12] based charge based on usage could distort operational decisions, with some stakeholders favouring an agreed capacity charging design so that operational dispatch decisions can be driven by market-based mechanisms (the wholesale market and flexibility markets) to support efficient operations. We discuss this in our Links with Procurement of Flexibility note, including the impact of the dynamic charging options discussed next. As discussed in our Distribution Locational Charging Model note, we note that improving the locational granularity of usage charges so they better coincide with the time of local network peaks could reduce the risk of distortions.

5.22. Finally, we some Delivery Group members suggested that DNOs do not currently take into account agreed capacity values, when planning their networks, but instead consider aggregated peak demand (adjusted for diversity, where applicable). In order for charges to be cost-reflective, they need to reflect the actual way networks are planned and costs are incurred. To determine this, we will need to undertake further work to better understand the link between network planning, assumptions made about the HV and LV networks and the charging approach, in order to confirm which options are most cost-reflective.

Dynamic charging options: Critical peak pricing or rebates and dynamic pricing

5.23. In our charging note, we also considered two dynamic charging options and peak rebates. Each of these options have advantages and disadvantages, which are summarised in Table 3 below.

Table 3: comparison between different dynamic charging design options

Design option	Advantage	Disadvantage
Dynamic charging (critical peak pricing) *Customers are notified in advance that there is going to be a critical peak period, during which high charges will be applied to consumption*	• More economically efficient than a static charging option, as peak charging periods more accurately reflect real-time network conditions • Limited number of times per year when a customer needs to change their behaviour in response to the charging signals • Creates an incentive for flexible services to reduce usage	• Feasibility challenges due to the level of network monitoring and forecasting required to determine when a critical peak period is expected • Difficult to predict and may require significant customer investment (or acquisition of third party services)
Dynamic charging (real-time pricing)	• Provides the most economically efficient	• Feasibility challenges due to the significant level of network

[12] We discuss the long run marginal cost model in our Distribution Locational Charging Model note

Customers are notified in advance of the price for every hour (or half hour), which reflects short-term network conditions	signals about when the network is constrained and gives the ability to vary the strength of the signal in near real-time to reflect the actual cost of managing constraints • Incentivises flexible services to reduce usage in response to sharp price signals	monitoring and forecasting required, in order to identify network conditions and set the price for the next hour (or half hour) • May be difficult for some small users to change their usage (ie may require technological solutions in order to benefit) • Difficult to predict and may require significant customer investment (or acquisition of third party services)
Peak rebates *This is similar to Critical Peak Pricing, except that the customer receives a rebate for actions taken during the critical peak period*	• Some of the literature suggests that this may drive a greater response from customers than a critical peak charge • Where customers are on a pass through tariff, a rebate is likely to be more acceptable than a sharp penalty during a critical peak period.	• Necessary to establish a baseline in order to identify whether a customer has taken the desired action • Feasibility challenges due to the significant level of network monitoring required.

5.24. Under the current Common Distribution Charging Methodology (CDCM) and Extra-high voltage (EHV) Distribution Charging Methodology (EDCM), charges are static. This means the unit rates and applicable time bands are set in advance of the relevant charging year and do not vary over the short-term in response to actual network conditions. However, it is also possible for network charges to be set on a dynamic basis where some or all elements are updated within the charging year to reflect network conditions and send price signals to customers about the impact of their behaviour on the local network. This approach, which requires more granular charges that better reflect local network peaks could reduce the risk of distortions. These signals could take the form of a charge where a customer's actions drive costs or a rebate where a customer's actions benefit the network (eg through reducing a constraint).

5.25. The Locational Cost Models subgroup has been considering network monitoring and connectivity mapping, as part of its work on different options for cost models. This is particularly to support consideration of whether a short run marginal cost (SRMC) based model, which would require a granular knowledge of actual network conditions. The subgroup identified in its published report[13] that DNOs only have extensive monitoring down to the primary substation level and, at HV and LV, there is less data available and the DNOs have relied on maximum demand data. The exception to this is where some DNOs have implemented more detailed monitoring in specific locations to support flexibility or active network management.

5.26. In order to effectively implement dynamic charging, the DNOs need to map much more accurately the electrical connection between customers at lower voltage levels and

[13] http://www.chargingfutures.com/media/1341/scr-locational-granularity-of-charging-report-v11.pdf

the relevant assets and introduce monitoring at the same levels across their whole networks, rather than in just some locations. This is in order to be able to segment a DNO region into more granular locations so charges can be set to reflect actual conditions on specific assets. Note that, although it might be possible to identify in real-time when EHV assets are constrained, this may not reflect when the networks are constrained at lower levels so sending a dynamic signal, based on the EHV network, may not result in more efficient use of the HV and LV networks. We discuss the extent that more locationally granular charging would be possible in our Distribution Locational Charging Model note.

5.27. The subgroup's current view is that it is not feasible to extend monitoring of their networks from the primary substation level down to LV by 2023. Although we note the subgroup's current view, we will work with them to further define the current limitations and scale of change that would be needed (noting this may vary by DNO). In addition to the work that was undertaken by the Delivery Group subgroups, we sent the DNOs surveys in late April to gather their views on the feasibility of our different charge design options.[14] Although a number of the DNOs indicated they were unable to estimate implementation timeframes to introduce short-term congestion forecasting and real-time pricing at this stage, those that did generally suggested it would take around five years. However, it should be noted that they all indicated they had low certainty that the estimates were accurate. We are minded that there may be an opportunity for such improvements in data availability to be aligned to the Energy Data Taskforce report recommendations.[15] We will be considering how we can take advantage of this as it informs our wider work relating to the modernisation of energy data.[16]

5.28. Finally, we interviewed our Challenge Group suppliers to understand the potential impact that some elements of our charging design options could have on their systems and tariff offerings.[17],[18] We asked the suppliers how they might treat dynamic DUoS charging options and responses can generally be summarised as:

- Larger industrial and commercial (I&C) customers may be able to respond to more dynamic price signals with sufficient notice. However, a number of suppliers noted that some customers in this group still prefer simple tariffs (ie a flat rate option that does not pass directly through to the customer the wholesale, network and other costs the supplier has incurred) so they can budget more effectively and would not be interested in dynamic tariff offerings
- The majority of domestic and small and medium sized (SME) customers prefer simple tariffs and a number of suppliers stated they would not propose to offer a dynamic charging option, unless they felt there was customer demand for it
- Many suppliers indicated that technology and automated solutions may be required for some consumers, as it will enable them or other third parties to undertake actions behind the scenes through direct load control and similar measures, without customers having to actively engage in their energy management. A key example of this is an EV tariff with a smart charger, which could enable the charger to be turned on, when prices are low (or turned off if prices spike), or throttle the speed of the charging in response to dynamic price signals.

[14] We also asked similar questions of the ESO which we consider in the TNUoS section.
[15] https://es.catapult.org.uk/news/energy-data-taskforce-makes-five-key-recommendations/
[16] https://www.ofgem.gov.uk/about-us/ofgem-data-and-cyber-security
[17] We invited all 12 suppliers from our Challenge Group to participate in these interviews, of which all with the exception of one supplier choose to participate.
[18] The suppliers' responses are summarised in the Engagement with industry stakeholders discussion note

5.29. Based on the work undertaken by the Locational Cost Models subgroup on the data available to support an SRMC based cost model, which is discussed in detail in our Distribution Locational Charging Model note, and the fact the data requirements are similar in order to implement dynamic charging, our preliminary view is that fully dynamic network charging may not be feasible for DUoS charges by our SCR implementation date of 2023. We recognise that the level of universal monitoring at a granular level required to enable dynamic network charging is extensive, and therefore could incur disproportionate cost and practicability issues. We are continuing to assess the cost and benefits of granular network monitoring, and encourage DNOs to continue making improvements to their network visibility.

5.30. Our consideration of dynamic charging options also reflects the fact that, unless suppliers reflect them in their tariffs, they might only elicit a limited behavioural response from customers. We note that some suppliers are developing innovative new offers in this area, such as helping optimise their customers' usage given market and charging signals.

5.31. Even if it is not feasible to implement full dynamic charging under our Access SCR, we consider that it is still important that, where possible, we improve the cost-reflectivity of static charges. To achieve this, we will continue to investigate whether to introduce seasonality, increase the locational granularity, and allow DNOs to set time bands that vary across a region. We also intend to consider whether there could be hybrids that can capture the merits of different options, for example whether a peak rebate could be added to an agreed capacity charge.

Section 4. Our preliminary considerations – application of individual basic options to TNUoS demand charges

5.32. In the previous section, we assessed the potential for the five basic charging design options to be applied to DUoS charges (including as credits for demand users in some instances, such as in a generation dominated area). In this section, we set out our preliminary assessment of whether they can be applied to TNUoS demand charges. Our initial view is that there are three broad approaches to reform of TNUoS demand charges that we could adopt:

- An ex ante **critical peak pricing approach**. We are proposing to not consider a critical peak rebate option, which is the inverse of the charging approach, because the existing approach has already proven to be effective in eliciting a response from users, as described in more detail below.[19] Our preliminary view is also that suppliers may be best placed to design incentives that engage their customers and elicit the desired response.
- Move towards an **agreed capacity approach**.
- Adopt a **static charging approach** based on actual energy consumed or actual capacity utilised during peak periods (i.e. volumetric time-of-use or actual capacity).

5.33. We consider that these basic options for reforming TNUoS demand charges have similar conceptual advantages and disadvantages as per our discussion of the options for DUoS charges, as described above in Section 4. However, we think that in the context of

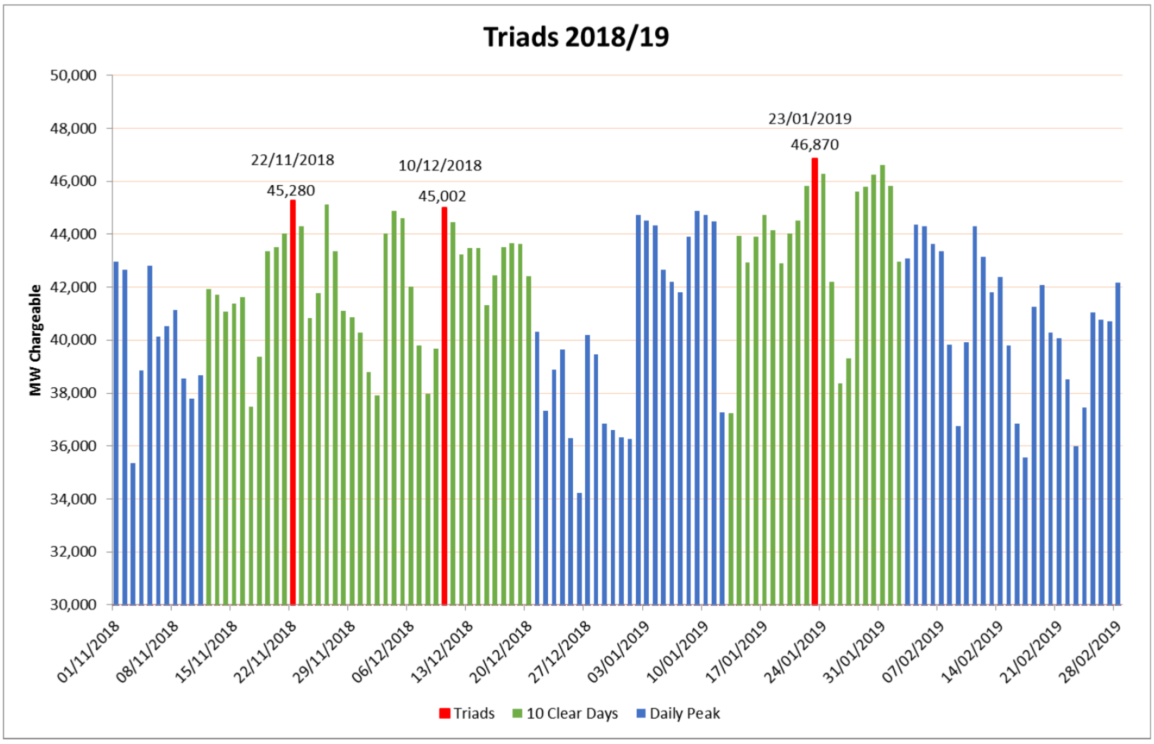
[19] In some cases, this response has been driven by residual charges being recovered during Triad periods, which we are reviewing as part of our Targeted Charging Review.

forward-looking transmission charges there are some specific considerations relevant to the assessment of options, which we discuss further below.

An ex ante critical peak pricing approach

5.34. The current Triad approach can be seen as an ex post critical peak pricing approach, with larger customers charged for their usage during Triad periods, which are the three half hour periods over winter where system-wide demand is highest (providing they are more than 10 days apart). This methodology is illustrated for 2018-19 in Figure 1 below.

Figure 1 – Triad dates for 2018-19 charging year



5.35. Although historically, Triad has been effective at encouraging customers to reduce their demand, we consider there are several reasons to consider changes to the current Triad approach for forward-looking charges:

- the Triad periods are becoming an increasing source of uncertainty. This creates significant financial risks for customers, if their general practice is to reduce demand during Triad periods but then they fail to correctly predict a Triad period (ie they did not reduce their demand in this period and therefore face a charge). For very large demand customers, we understand this may also be because they contribute such a significant amount to the peak that their usage determines when it may be, which means they are unable to avoid it through behaviour change.
- it is not clear how well Triad periods reflect the periods when network constraints are highest. This is because it is set on a GB-wide basis based on maximum system demand. For example, demand in Scotland currently gets paid credits based on the basis that they offset the need for transmission capacity to transport power from wind generation to southern-based demand. The network constraints caused by these flows may not be that well aligned with the Triad periods.

5.36. When considering whether there needs to be reforms to the current TNUoS demand charging approach, we are mindful that our initial research on academic literature indicates that critical peak pricing is considered to be one of the most cost-reflective approaches that can be adopted for electricity network charging. The Triad approach has also led to a significant reduction in peak demand,[20] with the ESO estimating that Triad periods generally have seen around a 2GW reduction in peak demand. Many suppliers have communication systems and channels for large users to be notified when a Triad period is forecast (see the Engagement with industry stakeholders discussion note, which summarises responses from our supplier interviews).

5.37. As such, and although it has drawbacks, Triad is a "tried and tested" and proven demand side response mechanism. Given this, one option is to introduce the following reforms to address the concerns raised with the current approach:

- An ex ante (ie in advance) critical peak pricing charging approach, which would provide customers with much greater certainty regarding when the peak periods will occur
- Greater locational granularity by having regional peaks, ensuring the signals customers receive reflect the actual conditions on their part of the network
- Additional critical peak periods, which will smooth TNUoS charges, rather than signals being focused just on three peak periods.[21]

Ex ante charging

5.38. Under an ex ante critical peak pricing regime, the ESO would notify suppliers in advance of when the peak period would occur and they would advise their customers so those who were able to could adjust their demand. In response to our network company feasibility survey, the ESO advised that their control room undertakes short-term forecasting. In addition, the ESO already receives the suppliers' forecast demand by Grid Supply Point group (ie all GSPs within a DNO region) along with individual demand data for a small number of very large demand users who are directly connected to the transmission system. This suggests that data may be available for ex ante critical peak pricing, although the accuracy of these forecasts may differ and there would be complexities to implement this.

5.39. With regards to notifying customers of an upcoming critical peak period, we understand the communication and other systems are already established for large demand users from suppliers and other third party agents. Our interviews with Challenge Group suppliers indicate these systems would not require significant change to notify large users in advance of a peak period because the majority of them already have an opt-in Triad warning service, which alerts users of a potential Triad period. However, work would be required to determine a) how these could be adapted to allow ESO to provide a signal in a timely manner; and b) whether the same approach could also be used to communicate with small users, if the Triad arrangements were extended to small users. We describe the

[20] We note that a degree of this behavioural change will have been driven by the fact that residual charges are recovered during Triad periods, which we are reviewing as part of our Targeted Charging Review. We are concerned that behaviour change driven by residual charges is distorting behaviour, increasing system costs while simply moving the burden of paying residual charges to less flexible consumers.
[21] Although moving to more than three critical peak periods would mean that it would no longer be a 'triad' charging methodology, we have referred to the approach as Triad throughout this chapter (reflecting the current arrangements) for simplicity.

outcomes of our supplier interviews in our Engagement with industry stakeholders discussion note.

5.40. We would only see a behavioural change during the peak charging periods, if we moved to an ex ante approach. This is in contrast to the current ex post Triad approach, where behaviour change occurs over a much higher number of periods as users seek to reduce the risk of incorrectly forecasting a Triad period. This may support there being a higher number of ex ante peak charging periods, which we discuss further below. A further potential issue is that, if customers know in advance when a peak period will occur, they may just defer consumption until after the period, resulting in the critical peak shifting slightly, rather than being smoothed.

5.41. We note that, given our initial view in the preceding chapter that it may not be possible to implement all the dynamic charging designs for DUoS demand charges, continuing with a critical peak pricing approach means the charging design might still be different for transmission and distribution demand users. We consider this further in the Cross-Cutting Considerations section later in this discussion note.

Regional network peaks

5.42. Under the current Triad approach, although the tariff varies by demand region (aligned with the DNO regions), the three Triad periods are determined by when the system as a whole peaks. This means some customers will receive a strong signal to reduce demand during a period when their regional transmission network is not constrained and do not receive a signal when reduced demand would be beneficial.

5.43. We are considering whether there may be benefits in making changes so critical peak periods are able to vary between demand regions to reflect actual network conditions and intend to undertake further work with the ESO to identify the extent that regional transmission network peaks coincide with the overall system peaks or not.

Additional critical peak periods

5.44. The third reform to the current approach is to increase the number of critical peak periods from three. This would address the criticism that the Triad signal is too sharp, although we recognise that this will be partly addressed by the changes to residual charges being considered under our TCR. Introducing more peak periods alongside an ex ante approach would also mean that the value of behaviour change is signalled across a higher number of peak periods. This would have value if there are more than three periods during which network assets are expected to be nearing capacity constraints and/or there was a risk that the ESO's forecasts of peak periods would not be fully accurate.

5.45. If our analysis supported an increase in the number of peak periods, we might also need to consider whether the number of peak periods should be fixed or could vary year on year (or between demand regions), reflecting network changes.

5.46. We will need to consider if there is a cashflow risk for the ESO where charges are set in advance, but the number of periods that revenue is collected from can vary within a range. Under this scenario, if there were less periods than expected when charges were set, the ESO could under-recover allowed revenues and need to seek a revenue adjustment in the following year. We will consider as part of our impact assessment the holistic impact of any proposed changes on the ESO's ability to forecast accurately and collect TNUoS demand revenues.

Move towards an agreed capacity approach

5.47. As described in Section 3, one of the options for the DUoS charging design is **agreed capacity.** In order to remove one of the differences between the charging arrangements, we are considering whether such an approach should also be applied to TNUoS demand charges.

5.48. Under an agreed capacity approach, the ESO would need to know each customer's agreed capacity in order to calculate charges on a £/kW or £/kVA basis. Although there are several ways this could be achieved, including the ESO agreeing capacities directly with customers, our initial view is that the simplest option would be for the ESO to use the capacities agreed between the DNOs and customers (or suppliers on their behalf) for their access to the distribution network, as the basis for TNUoS demand charges. As such, this option would have a significant dependency with the approach to charge design for DUoS – if DUoS charges do not incorporate agreed capacity charges, then it would be difficult to adopt agreed capacity charges for TNUoS demand charges also.[22] We note that the ESO does have contractual relationships with demand customers directly connected to the transmission network and so could more readily agree capacities with these customers. However, these represent only a small proportion of demand. We also note that the issue of defining distribution connected customers' access rights for the transmission network is relevant here. As set out in our Access Rights discussion note, we intend to cover this in more detail in our second working paper.

5.49. An important impact of moving to an agreed capacity approach to charging is that it would place more emphasis on users' access right choices and trading, and/or flexibility procurement by the ESO and DNOs as a way of sending operational signals to users about where there is a need to turn up or down to support network management. We discuss the interaction with flexibility in our Links with Procurement of Flexibility discussion note.

Adopt a static charging approach based on actual energy consumed or actual capacity utilised during peak periods

5.50. Static time-of-use, actual capacity and Triad approaches all share a similarity in they are based on a user's actual consumption or actual capacity during peak times. However, the Triad approach, which is a form of dynamic charging, should be more economically efficient than a static charging option, as charging periods are set closer to real-time and so can more accurately reflect peak network conditions. This is consistent with our assessment of DUoS charging design options. Accordingly, in applying our first Guiding Principle (on economic efficiency), continuing with a Triad (or reformed Triad) approach appears to rank higher than a static time-of-use or actual capacity option.

5.51. Although the Triad approach might be more economically efficient conceptually, we also need to consider our other Guiding Principles, including the nature of energy as an essential service (Guiding Principle 2). As discussed in Section 4, we consider a volumetric

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[22] We note there is also potentially a dependency with our decision under the Targeted Charging Review – if we decide there to use agreed capacity as the basis for residual charges then this will require the ESO to obtain agreed capacity data from DNOs.

time-of-use charging option may be easier for small users to understand than Triad or actual capacity options. We will need to consider further the most appropriate arrangements for small users and will consider this further in our second working paper.

5.52. A further factor in why a volumetric time-of-use or agreed capacity charging design could be applied to TNUoS charges is whether we adopt one of these options for DUoS charges.[23] In such a case, there might be an argument to adopt the same charge design at the TNUoS level for consistency. This might promote our second Guiding Principle, by enabling users or suppliers to understand better the charging arrangements due to greater alignment between TNUoS and DUoS charges and therefore simpler arrangements overall.

5.53. For both of these approaches, there is a question about whether there should be increased seasonality in charges, consistent with the discussion in Section 6 in relation to DUoS charging design. For those small users who are currently electively half-hourly settled or who move to half-hourly settlement in the future, there is an additional question as to whether the approach to larger users (which could be a reformed Triad mechanism or something else) should be applied. We intend to consider these questions in further detail in our second working paper.

Section 5. Our preliminary considerations – cross-cutting policy issues for DUoS charging design

5.54. In addition to our assessment of the individual charging options, we have considered a number of cross-cutting issues relating to DUoS charging arrangements, which we discuss in this section. We discuss cross-cutting considerations relating to TNUoS charges in the following section.

How should peak use or capacity be measured?

5.55. Forward looking charges are predominantly driven by reinforcement required to meet future peak capacity and therefore the charging regime will need to measure this, in order to send signals to customers. There are three key options for measuring peak usage:

- Consumption (kWh) recorded over a short defined period can serve as a measure of peak usage. For example, the HH settlement period with the highest consumption.
- Measuring capacity in kW takes into account active power, which refers to the real power being carried by an electrical current.
- Measuring capacity in kVA refers to ‘apparent power’, which takes into account both the active power measured in kW and reactive power measured in kVArh.

5.56. When deciding on an appropriate method for measuring peak capacity, we also need to consider whether the meters have the technical capability to record to necessary information. We describe different meter types’ functionality in Table 4 below.

[23] The seasonality, locational granularity and time-of-day elements that we are considering for DUoS charges could also be applied on a transmission level to increase the cost-reflectivity of the volumetric time-of-use and actual capacity charging options.

Table 4: technical differences between smart meter types

	Able to measure:				Able to be remotely read
	kWh	kW	kVA	kVArh	
Automated meter reading (AMR) device fitted	√	√	√	√	√
SMETS[24] version 1 (SMETS1)	√	√[25]		√	√
SMETS2	√	√		√	√

5.57. Although not all meters are able to record peak capacity, it can still be calculated using data that is measured by the meters. For example, it is possible to use consumption data over a half hour period to calculate average maximum demand in kW. Therefore, on its own, metering capabilities do not necessarily preclude any of the ways to measure peak usage. In deciding on an appropriate approach, our preliminary view is the considerations should include:

- Whether there is a benefit in adopting the same measurement of capacity for all users, or whether there should be continuity for users in how capacity is currently measured for them.
- Whether there is a benefit in adopting a simpler to understand measurement of capacity for small users, such as kWh over a short period.

Is it cost-reflective to have a flat volumetric or fixed charge component of forward-looking charges?

Flat volumetric charges

The subgroup also considered whether any of their costs vary according to volumes of energy consumed. They concluded for both transmission and distribution that, similarly to customer numbers, although overall consumption is one of the factors that influences ongoing costs on the network, it is not the key factor. Instead, it is one of a number of other considerations, such as the level of environmental salinity, maintenance costs and generation required to support demand.

Given the conclusions of the subgroup, our preliminary view is that flat volumetric DUoS charges are not cost-reflective, as they do not specifically incentivise customers to reduce consumption at times when the network is (or is predicted to be) constrained.[26] However, although the use of flat volumetric charges may not meet Guiding Principle 1 with regards to cost-reflectivity, we recognise that applying them for small users may support Guiding Principle 2. This is because these customers may have less flexibility with when they consume energy or are less able to invest in technologies to achieve this. For example, if all, or a significant proportion, of the forward looking charge was recovered over a very small period of time (i.e. the network peak), then the unit rate for energy consumed during

[24] Smart metering equipment technical specification: https://www.gov.uk/government/consultations/smart-metering-equipment-technical-specifications-second-version
[25] A remote party is able to get an instantaneous reading from the relevant register but the meter does not have a log of the information
[26] We will take additional analysis to determine whether to continue with some form of peak or time profiled volumetric charges as part of any changes made under the SCR

that period would be much higher than under a flat volumetric charging regime. If the peak period coincides with when families come home from work, cook dinner, etc, then they could face significantly increased charges.

We will be specifically focusing on small user issues, including any protections that should be applied for them, as part of our next working paper to be published later in the year.

Fixed charges

Although we are yet to reach a decision on whether there should be a cost-reflective fixed charge under the Access SCR, under the TCR, we consulted[27] on a leading option of recovering residual costs through a fixed charge. This is because the purpose of residual charges is to recover any difference between the DNOs' allowed revenue under their price control and forward looking charges, rather than sending a signal to customers to change their behaviour. We propose to publish our decision on the TCR later this year. In this section, we consider whether there is a case to include a fixed charge element as part of the forward-looking charges.

Under the current CDCM and EDCM, customers pay fixed charges that primarily relate to operating costs associated with assets that are not (or are potentially not) shareable, which are known as sole use assets. This subsection is focused on costs that are driven by customer numbers and can be recovered through daily fixed charges (e.g. p/MPAN/day), rather than forward looking charges.

Analysis in the Cost Drivers subgroup's report, identified a small number of costs that are driven by customer numbers, such as Ofgem's licence fees, which are allocated to DNOs based on their number of MPANs, and call centre costs, which would need to increase, if there was a significant increase in customer numbers. The DNOs also noted that some of them have Quality of Service standards that limit the number of customers that can be connected to LV and HV circuits, which may also influence when additional reinforcement is required. Although it is apparent there are some costs that have a clear link with customer numbers, further work would need to be undertaken to determine whether these costs are sufficiently material to merit a separate fixed charge component of DUoS charges.[28]

Should certain users face reactive power charges?

5.58. Given reactive power charges only apply to some customers under the current arrangements and it is quite a technical subject, we put the explanation of what it is and a detailed discussion of our initial views in the annex to this note. In summary, under the current CDCM, some half-hourly settled customers (generally considered to be larger customers) incur reactive power charges, once their reactive power exceeds 33 per cent of total active power. Our Cost Drivers subgroup concluded that, although there are not any

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[27] https://www.ofgem.gov.uk/system/files/docs/2018/11/targeted_charging_review_minded_to_decision_and_draft_impact_assessment.pdf

[28] We note that, the transmission analysis identified that customer numbers have a direct relationship with network constraints and therefore the need for reinforcement, due to the impact that a significant increase in connections would have on costs and this could equally be applied to distribution costs. However, the key driver would still be peak capacity.

examples of reactive power driving reinforcement costs, it is a component of overall network loading (ie it takes up capacity and so may contribute to the need to reinforce).

5.59. As reactive power charges are only applied to reactive power in excess of the requirements set out under the national terms of connection, our preliminary view is that they should continue to be paid, if charges are based on kW or kWh. However, consistent with an exemption introduced under DCP22,[29] our initial view is that generators should be exempt from reactive power charges, where they have entered into agreements with the DNO to adjust its reactive power. We will consider further whether reactive power charges should apply to a wider group of customers.

Should seasonality be reflected in forward-looking charging signals?

5.60. Under the current DUoS methodologies, only the EDCM contains a seasonal element in the 'super red' unit rate, which applies on weekdays during the months determined by each DNO as being the peak period. For all of the DNOs, the peak period occurs between November and February inclusive,[30] although the actual hour reflect the specific conditions in each DNO region. However, these all occur between 4pm and 7:30pm. There is also a seasonal element under the Triad approach, which applies during the three highest peak periods between November and January that are separated by 10 clear days.

5.61. Under the CDCM, the time bands apply year round. The DNOs have carried out an initial assessment of the primary substations in a subset of DNO regions,[31] which indicated that, of their substations which had schemes requiring intervention,[32] the majority of them experience their period of highest demand during winter. However, as set out in Table 5 below, there are also substations, which experience summer peaks, which suggests that it may not be more cost-reflective to introduce seasonal charges in winter only.

Table 5: percentage split of substations between summer and winter peaks

	EHV	**132kV**	**Overall**
Substations with **summer** peaks	8%	7%	16%
Substations with **winter** peaks	65%	19%	84%

5.62. Northern Powergrid (NPg) undertook an exercise to identify the season that each of their primary substations experiences its maximum peak period. It can be seen from the maps in Figures 2 and 3 that, although the vast majority peak during winter, a significant number of primaries peak during the other seasons. In addition, in the major towns, such as Leeds, Hull and Sheffield, there are an almost equal number of substations that peak during spring as during winter.

[29] In August 2016, we approved DCP222, which amended the CDCM so that, where a half-hourly metered generator has entered into an agreement to adjust its reactive power, it will be exempt from reactive power charges. The decision is here:
https://www.dcusa.co.uk/Documents/DCP%20222%20Authority%20Decision%20Letter.pdf
[30] Note that UKPN's London region also includes a summer peak from 11am to 2pm during June to August
[31] A primary substation is one at which the primary voltage is greater than HV and the secondary voltage is HV (covers 132/11kV substations).
[32] To ensure consistency, the subgroup used data reported to Ofgem, as part of their regulatory reporting packs. The specific data related only to substations where interventions would be required.

Figure 2: seasonal peak for each primary substation in NPg's North East region

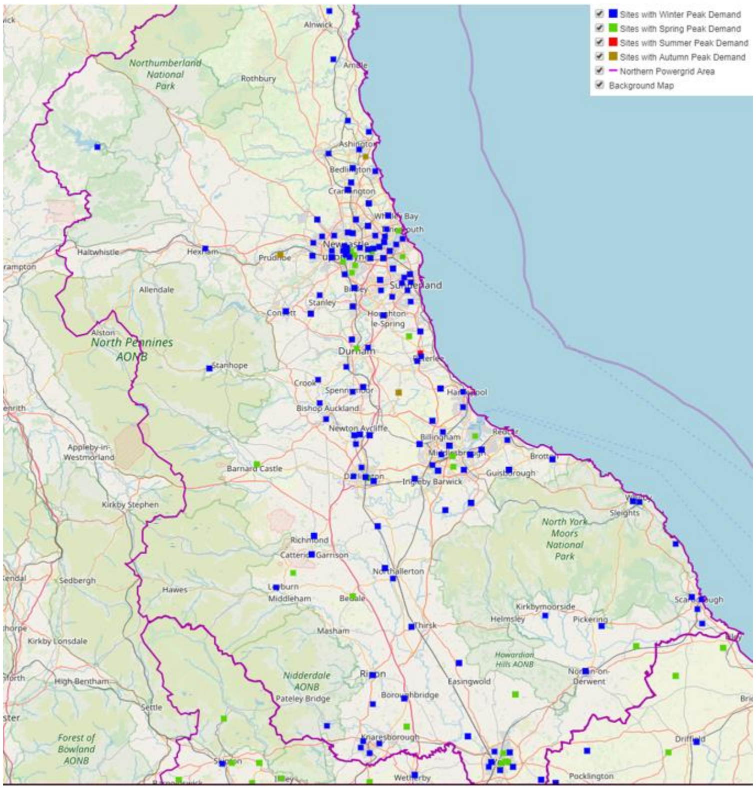
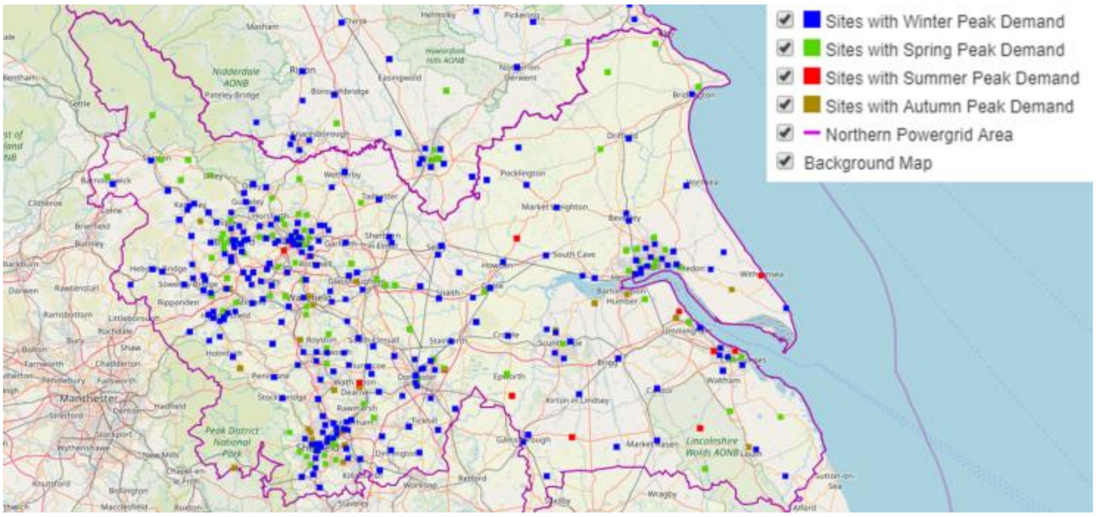


Figure 3: seasonal peak for each primary substation in NPg's Yorkshire region



5.63. This initial evidence suggests that it may not be cost-reflective to introduce winter peaking across the whole of NPg's regions, due to the number of substations that peak in the other seasons. However, when deciding on the degree of seasonality to include, we will need to consider the trade-off between cost-reflectivity and simplicity, as we are already aware from the current methodologies that too much complexity can make it difficult for parties to understand how costs are assigned to them. Some examples of the trade-off we will need to consider are:

- As discussed below, we are also considering the time-of-day that peaks occur, which, when combined with the seasonality assessment, might indicate the most cost-reflective approach would be to also introduce separate winter peak periods across a DNO region.

However, it may not be proportionate to do this, due to the administrative burden and the complexity for customers, when compared to the benefit of variable winter periods.

- As can be seen in the NPg maps, there are some substations that peak in summer and a number that peak in spring. Unless a decision is made that charges should be applied at the primary substation level, there will need to be some aggregation in order to apply time bands, charges, etc. Given the majority of substations peak in winter, it would be simplest to apply a winter peak, even where some substations peak in a different season, but this would send an inaccurate signal to customers who impact on the assets that peak at different times of year.
- Ensuring any changes to reflect seasonality are future proofed and can vary over time, as usage on the network changes (eg managing summer conditions is becoming more of an issue). We will consider how to set out the requirements for seasonality, including whether to prescribe in the DCUSA or allow DNOs discretion to determine the seasonality annually, as part of our further assessment.

5.64. The assessment described above indicates that it may be more cost-reflective to introduce seasonality, which would ensure the signals faced by customers better reflect their impact on the network at different times (e.g. a sharper signal in winter would incentivise customers that are able to, to consider reducing their usage). However, we recognise that this may not mean that the same seasonal peaks apply at all voltage levels (e.g. the bulk supply point may have an autumn peak, even though the grid supply point and primary substation have winter peaks) and, therefore, introducing seasonality may not improve cost-reflectivity down to the individual customer. We will need to consider in greater detail whether the peak signal received by customers at the lower voltages should be at the primary substation or some other level.

5.65. Although it may be more cost-reflective to introduce seasonality, we are mindful that it could significantly increase charges at times when usage is highest, as more costs will be recovered from a smaller period of time. Where a winter peak is identified, we will need to consider whether this would result in an unacceptable level of bill shock for small users, who may be unable to respond to price signals, as they still need to warm their homes. We note, however, that it could be possible mitigate this through the choice of charging design, for example a capacity ‘subscription’ approach where a customer would be moved to a higher capacity band, where their consumption exceeded an agreed level.

5.66. In addition to the choice of charging design, suppliers have discretion as to how they pass through charges to their customers and so may also be able to mitigate the impact of seasonal charges, for example by smoothing the impact of network charges and other costs throughout the year. Although the majority of the suppliers we interviewed in June indicated they offer pass-through tariffs to larger users, most suggested that they would not pass-through the impact of seasonality to small users, as they prefer simple charges and they were concerned about the risk of bill shock. However, several suppliers indicated they might be able to use technology or other approaches to manage customers’ assets on their behalf to optimise charges (eg through an EV smart charger).

5.67. We will undertake further analysis to determine whether seasonality should be introduced, including the likely benefit, if suppliers do not pass the costs on to some categories of customers, and, if our analysis supports it, we will need to undertake further assessment to determine the most appropriate mechanism for introducing the requirement.

Should the time bands for forward looking charges differ across a DNO region?

5.68. Under the DUoS charging methodologies, there are differences in how time-of-day differences are reflected in charges – under the EDCM, each DNO nominates a single peak time period during which demand customers are charged for their consumption (this is called the 'super red' period) and under the CDCM, each DNO nominates a peak period called the 'red' time band, a shoulder called the 'amber' time band and a 'green' time band that applies when it is not expected that the system is constrained. Under both methodologies, the time bands apply across the whole DNO region. The CDCM time bands that apply on weekdays are set out in Figure 4 on the following page, while for the EDCM, the super red winter period occurs between 4pm and 7:30 in all regions (note that UKPN London has a summer super red period between 11am and 2pm).

5.69. As part of our consideration of cost drivers and locational granularity, we are assessing whether it would be more cost-reflective to apply different red/amber/green (RAG) ratings or "super red" periods within a DNO region and, if so, the basis on which customers could be segmented. UKPN provided us with data that indicates that, in the London region, there is a significant number of primary substations that peak during the afternoon (between 2:30 – 3:00pm), rather than during the traditional 'tea time' peak period. This is set out in Figure 5 on the following page. This is consistent with the seasonality analysis, which indicated urban areas might have different characteristics to less built up areas.

5.70. We plan to work with the DNOs to understand better whether these kinds of additional peaks also exist in other DNO regions. If it does seem likely that there is sufficient variation within a number of DNO regions to support more granular application of time bands, we will need then to determine whether there are specific characteristics to enable them to be applied to different customer segments (e.g. urban vs. rural).

Figure 4: CDCM weekday time bands for all DNO regions

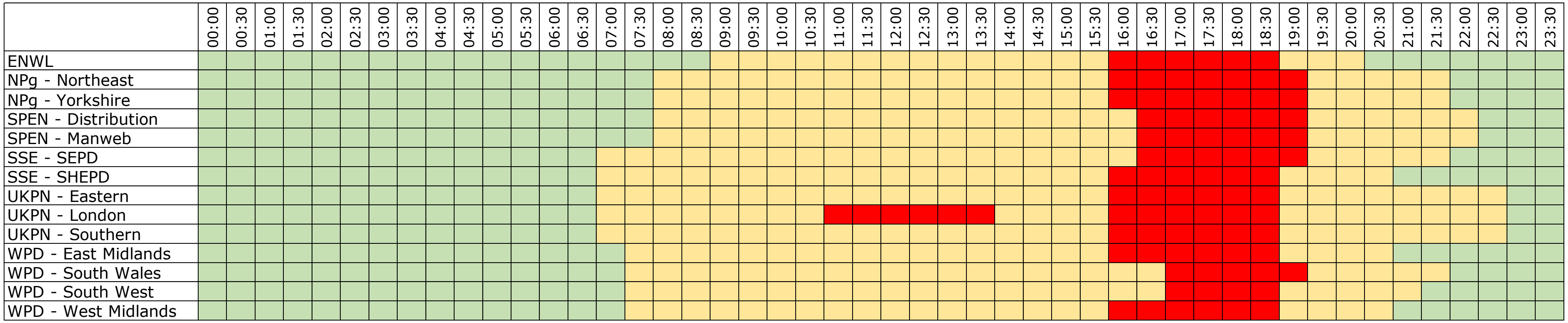
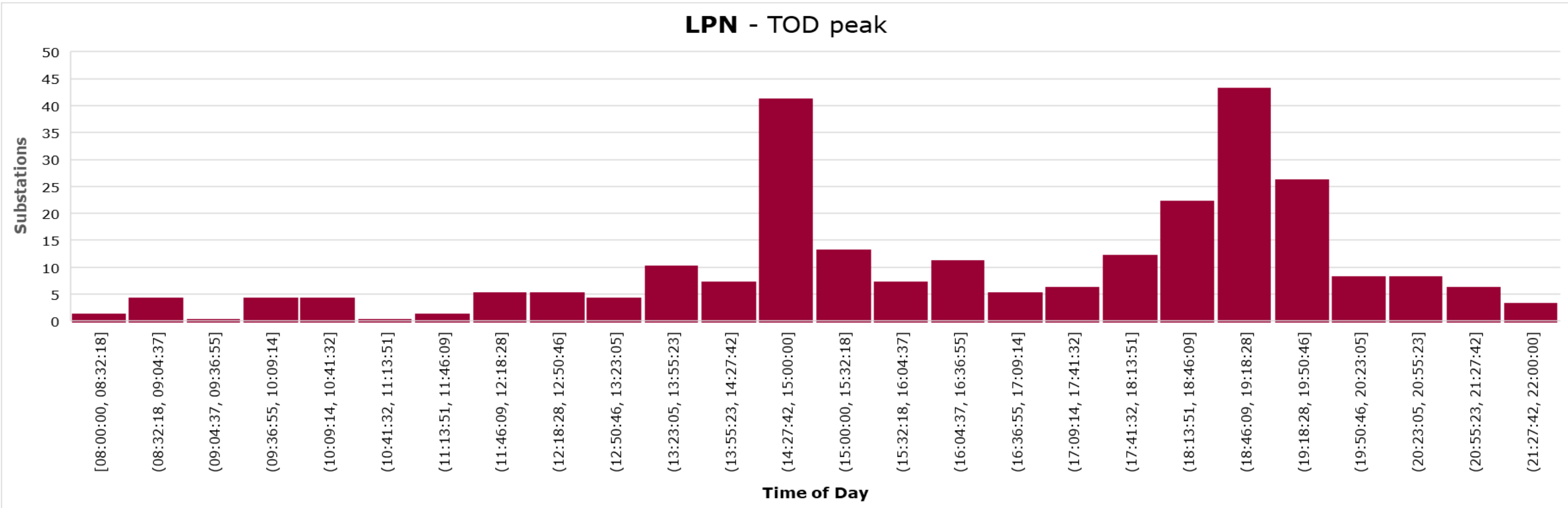


Figure 5: Time of day peaks for all primary substations in UKPN's London region



What is the purpose of shoulder or amber pricing signals?

5.71. Under a time-of-use charging regime, there are generally three unit rates, which apply at different times and seek to send signals to customers about the times when there is the highest probability that the whole system is peaking. The purpose of applying a unit rate during the green time band is to reduce the sharpness of the signal sent at peak times by recovering a proportion of costs at other times.

5.72. As forward looking costs are driven by peak usage, we will need to decide whether there is a case for incorporating an amber time band into charges. There are two key reasons for having an amber time band:

- The first is to address locational differences between the time that the whole system peaks and when local assets peak. The amber rate helps ensure customers who use the network at times that are close to the system peak time also face the costs of this usage.
- The second reason relates to future proofing to avoid customers responding to signals to move only slightly from the red time band, thereby simply causing the peak to shift slightly. By using an amber time band, customers are incentivised to move their consumption further from the peak period, which will help to smooth out the peak.

5.73. The potential misalignment between a system-wide peak time band and local asset peaks described above is illustrated in Figure 6 below, which shows analysis carried out by an Australian electricity distributor (Ausgrid), as part of a report[33] on changes to the company's network charging structure. The graph illustrates the extreme variation in local peaks across the network (approximately 9am to 9pm) and the role the amber time band plays in creating an additional incentive for customers to move their consumption further from peak periods. The chart outlines the peak times by substation from those substations which are dominated by household load listed first (which peak later) to those substations which are dominated by business load later (which peak earlier). There are many differences between Australia and Great Britain which means the particular times of peak may not reflect conditions in Great Britain. However, the chart illustrates the point that within a DNO region it is not unusual for there to be a lot of variation in the times of local peaks, with the times of overall system peak representing effectively an average which can hide some of these differences.

5.74. Figure 6 also illustrates the potential network benefits, discussed previously, of improving the granularity of the areas that charges apply to in order to reflect local network conditions. If charges reflected the local assets and usage at each primary substation (the most granular level considered to be currently possible on the DNOs' networks by the SCR implementation date), then charges could be aligned with the actual time that local assets peak. In such cases, it would reduce the need for amber prices, as customers would face charges that correlate with actual network conditions. However, if each DNO region was only broken into a smaller number of locations (but less granular than by individual substation), then it is probable that a number of asset peaks would still diverge from the locational network peak.

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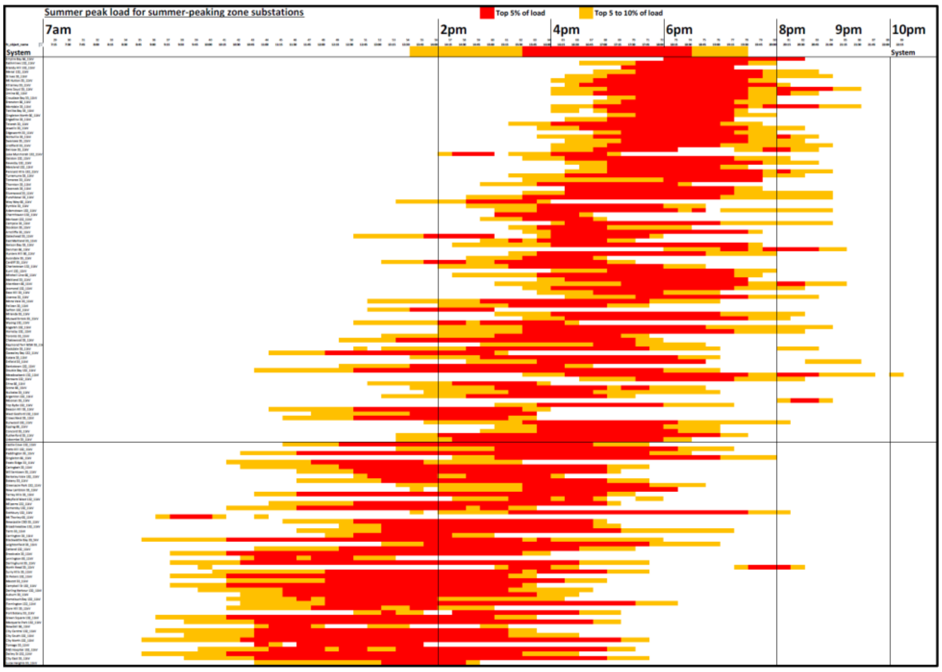
[33] https://www.aer.gov.au/system/files/Ausgrid%20-%20Revised%20Tariff%20Structure%20Statement%20-%20October%202016.pdf

Figure 6: time of peak demand for Ausgrid's summer peaking substations



5.75. We will be undertaking further work on the degree of locational granularity that should be applied to DUoS charges, including identifying the time of day that different local assets peak and the degree of divergence across the DNO regions. We will also consider the degree that having three time bands will still create "cliff edges" where customers cluster, rather than spreading usage over a wider period of time. Possible options for addressing this include increasing the number of time bands and applying a normal distribution curve around a peak charge, which smoothes prices over the day.

What determines the ratio between peak and non-peak pricing signals?

5.76. Under a peak driven charging methodology, there will be an element of charges that is recovered from usage at peak times and others that are recovered through non-peak charges. The ratio between these, however, is not generally something that is explicitly decided, but instead is determined by a number of factors, such as those we have discussed through this chapter and the proceeding Cost Models chapter. The exception to this would be if we decided to introduce a charging structure that is solely made up of a peak driven charge and a fixed residual charge. We identify the impacts these can have on the ratio in Table 6 below.

Table 6: impact of factors on ratio between peak and non-peak charges

Factor	Impact on ratio
Included costs categories: As discussed in the Cost Models chapter, we are considering whether there is a case for costs, such as replacement costs, to be included in the forward-looking charges. If such costs are included, a proportion of them will have a 'peak driven' element, which would change the ratio between peak and non-peak costs and the associated signals.	

Amber rates: Under a time-of-use tariff structure, it is generally accepted that the 'red' rates relate to peak-related usage. However, as noted previously, unless very granular locational charging was introduced, it is likely that a number of assets (eg primary substations) will peak at a different time to the peak that charges are attributed to. Where the evidence suggests that this is the case, we will consider applying 'amber' charges to capture costs that are driven by more localised network peaks.	↓
Seasonality: We have previously discussed the factors that would influence whether to reflect seasonal differences in network charges. If seasonality was introduced, this would result in changes in the ratio between peak and non-peak charges within year (eg if peak driven costs were only recovered in winter, then the peak ratio would increase). However, it is evident that this would also have the reverse effect during other seasons when charges for peak related usage are low.	↑
Reactive power charges: If some customers are charged for their reactive power consumption, this will reduce the level of costs to be recovered through peak-related charges. However, the level of the reactive power charges may still be linked to the network peak, due to the fact reactive power reduces network capacity, including at peak times, which drive costs. As discussed earlier, we will work with DNOs to determine whether it is cost-reflective, and consistent with our guiding principles to include reactive power charges.	↓

5.77. Although, as described in the table above, the ratio of peak to non-peak pricing signals sent through charges is influenced by a number of factors, we will assess the combined impact of the different elements to ensure the final charge design does not unfairly penalise some customer segments (e.g. domestic customers who cannot move their consumption).

Should suppliers be charged separately for each of their user's individual consumption or on an aggregated consumption basis?

Under the current CDCM, there are two different approaches to how suppliers are billed for their users' consumption:

- For customers in Measurement Classes C and E, who are generally considered to be medium and larger customers, suppliers are billed based on each customer's individual consumption
- For customers in Measurement Classes F and G, who are generally considered to be small customers, suppliers billed based on the aggregated consumption of all customers within that class.[34]

Our wide ranging review of DUoS charges under the SCR presents an opportunity to consider where to introduce individual supplier billing for all customers. The key potential benefits are:

- That suppliers will more easily be able to identify individual customer's consumption and the amount they have been charged for each of them. However, we understand from

[34] Aggregate billed HH metered charges were introduced under DCUSA change DCP179: https://www.ofgem.gov.uk/sites/default/files/docs/2014/10/dcp179_d_0.pdf

discussions with Challenge Group suppliers that aggregated bills would not prevent them from being able to identify their customers' consumption and associated costs.

- It may enable us to consider charging design options that we consider may not scale well under aggregate billing.

There are, however, two key issues with individual customer billing, which we will need to explore in more detail, before making a decision:

- System cost changes: As mentioned previously, DNOs have indicated that they would need to upgrade their systems in order to handle such a large increase in consumption data. In the responses to our feasibility survey, we were provided with cost estimates of up to £5 million with an implementation time period of up to five years. Note that this only refers to the billing system, which is used by all the DNOs, and individual DNOs may incur additional costs.
- Data privacy and access: Under condition 10A of the current DNO licence,[35] the DNOs are not able to access domestic and microbusiness consumption on a disaggregated basis. As a result, the licence would need to be amended, in order to enable them to undertake individual billing. In addition to the statutory consultation required to amend the licence, because domestic and microbusiness consumer half-hourly data is considered personal data[36], we would undertake a data protection impact assessment (DPIA), in line with the General Data Protection Requirements (GDPR).[37]

Rather than billing suppliers individually for each of their customers DNOs could continue with the current approach of basing bills on aggregated consumption data. We note that this approach is consistent with the arrangements for TNUoS demand charges, which are calculated using each supplier's forecast of their customers' aggregated half-hourly triad demand. Based on the considerations described above, it would seem that continuing with aggregate billing is more consistent with Guiding Principles 3, as it would avoid additional system and code modification changes, which may not deliver network benefits. However, we need to engage further with DNOs and suppliers to better understand whether there are any issues with this approach before making a decision. In addition, it is still unclear whether it is possible to implement all of our charging design options or access right choices, unless DNOs are able to access disaggregated consumption data (eg to calculate exceedance charges). We will do further work with the DNOs and suppliers to determine whether aggregated billing is possible or we need to undertake a DPIA, as described above.

Who should calculate network charges and bill suppliers?

We have described above that DNOs are currently unable to access individual domestic and microbusiness customers' consumption data on a disaggregated basis. In addition to arrangements for billing suppliers, this data limitation also has an impact on the DNOs' ability to calculate network charges suppliers have incurred. One option for addressing this is to seek to make changes to the licence to give DNOs access to disaggregated consumption data for the purpose of calculating network charges. As noted above this would require us to undertake a data privacy impact assessment (DPIA) and, subject to the calculated risk ratings, liaise regularly with the Information Commissioner's Office, during

[35] https://epr.ofgem.gov.uk/Content/Documents/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20%20-%20Current%20Version.pdf?utm_source=ofgem&utm_medium=&utm_term=&utm_content=licencecondition&utm_campaign=epr

[36] Domestic and microbusiness consumption data is classed as personal data because it can be traced back to an identifiable individual via the MPAN. Data from other groups of consumers (including larger SMEs) is not considered personal, as it is not sufficiently associated with an individual.

[37] https://ico.org.uk/for-organisations/guide-to-data-protection/guide-to-the-general-data-protection-regulation-gdpr/

the development of any licence amendments. Assuming none of the changes are rated as high risk, we would not be statutorily obliged to maintain ongoing engagement with the ICO, but we would still need to undertake a further statutory consultation to amend the licence.

An alternative option we are considering is whether it would be possible to centralise calculation of network charges with a third party that would be permitted to access disaggregated consumption data in order to calculate network charges and bill suppliers (we assume the rates would be provided by the DNOs). We have discussed with ELEXON the feasibility of them carrying out the third party role, given the access they may have to disaggregated half-hourly consumption data for settlement purposes under reforms being worked up through the Settlement Reform SCR,[38] but will also consider whether there would be benefits in a different third party carrying out the role. We have been considering how our reforms interact with our work on market-wide HH settlement, where we undertook a DPIA as part of proposed changes to data access for settlement purposes, under the Settlement Reform SCR,[39] in order to understand whether there would be any barriers to ELEXON carrying out this role under the proposed changes. In addition to data access considerations, we have been exploring whether there are any cost efficiencies to be gained from centralising development of a network charging and billing system, as part of the market-wide half-hourly settlement (MHHS) Target Operating Model,[40] rather than changes being made by individual DNOs.

In order to weigh up the potential benefits and issues with centralising calculation of network charges, we have discussed it with our Delivery Group, which has representatives from all the DNOs and the ESO. They have highlighted a number of issues to consider:

- The DNOs all have different schedules for calculating and issuing bills and the process by which it is done. As DUoS charges are their main income stream, the DNOs were concerned about the impact on their short-term treasury forecasts and suggested there would need to be service level agreements (SLAs) put in place with a third party provider.
- At the moment the DNOs' figures are heavily scrutinised by both internal and external auditors. This also includes reviewing the DNOs' controls around calculation of DUoS charges, which means the audit arrangements may need to be established with the third party.
- The DNOs currently have to do a lot of work in addition to calculating and billing for network charges, including managing debt collection and responding to queries from customers (notably those on pass through contracts) regarding their bills. If these responsibilities passed to ELEXON, this would create significant additional work for them, which would also need to be managed through SLAs, as some apply to the DNOs under their price controls.

In addition to the issues raised by the DNOs, there are several other points we have identified through conversations with other stakeholders that we will need to consider:

- Because the majority of DNOs use the same billing system, we understand any changes would only need to be made once and the cost could be shared between all the DNOs.

[38] https://www.ofgem.gov.uk/publications-and-updates/decision-agent-functions-under-market-wide-settlement-reform
[39] https://www.ofgem.gov.uk/publications-and-updates/consultation-access-half-hourly-electricity-data-settlement-purposes
[40] https://www.ofgem.gov.uk/electricity/retail-market/market-review-and-reform/smarter-markets-programme/electricity-settlement

- If approved, the changes proposed under MHHS will only give ELEXON access to individual half-hourly consumption data for settlement purposes. However, if we choose to implement a charging design that is not consumption based (e.g. agree capacity), then ELEXON would not have access to the necessary data to do the network charging calculations. Therefore, the suitability of a centralised third party solution is partially dependent on any changes to the charging arrangements or alternatively on our development relating to the Energy Data Taskforce[41] and our wider work on Modernising Energy Data[42].
- Finally, although ELEXON might have access to disaggregated data for calculating distribution charges, we will need to consider whether this also extends to using the data to bill suppliers on the DNOs' behalf.

Our preliminary view is that requiring the DNOs to use a third party billing service may introduce additional risks to the DNOs and more complex contractual arrangements. However, consistent with our discussion regarding aggregate billing, we will need to engage further with stakeholders to confirm whether there are any issues with continuing with the current approach.

Section 6. Our preliminary considerations – cross-cutting issues for DUoS and TNUoS charge design

5.78. In this section, we consider a key cross-cutting issue – the extent to which there should be alignment of charging design approaches across transmission and distribution, and across different types of user.

5.79. One of the key drivers for our review is the potential for distortions in the investment or operational decisions of users if there are undue differences in the forward-looking charging arrangements between different types of user. Distortions could be caused by material differences between treatment of different types of user which do not have objective justification. This could include:

- Differences between treatment depending on what voltage a user is connected to, for example whether they are connected at transmission or distribution level.
- Differences between treatment depending on the type of generation, for example whether they are a large or small generator, located with demand ("onsite generation") or not ("standalone generation") or between different types of generation technologies.
- Differences between treatment depending on whether they are generation or demand.

5.80. Table 7 summarises how the current forward-looking charging arrangements vary for different types of user. The application of different charging methodologies to demand and generation for TNUoS, and across TNUoS and DUoS, reflects historical differences in the way the networks were used.

[41] https://es.catapult.org.uk/news/energy-data-taskforce-makes-five-key-recommendations/
[42] https://www.ofgem.gov.uk/about-us/ofgem-data-and-cyber-security

Table 7: current application of transmission and distribution forward looking charging arrangements

Type of user	Transmission charges treatment	Distribution charges treatment
Transmission connected generation	Transmission generator charges, based on TEC (both "wider" TNUoS charges and local charges).	Not applicable.
Larger (>100 MW) distribution connected generators	Transmission generator charges, based on TEC (excluding transmission local charges).	Distribution generator charges. These could vary depending on whether they are connected at EHV or HV/LV.
Small (<100 MW) distribution connected generation	Embedded Export Tariff (broadly the inverse of forward looking transmission demand changes), based on generation during Triad periods, but capped at £0 (i.e. only receive credits or face zero charge, depending on what zone they are in).	Distribution generator charges. These could vary depending on whether they are connected at EHV or HV/LV.
Onsite generation (when exporting on to the network, providing less than 100MW)	Treated the same as small distributed generation.	Distribution generator charges. These could vary depending on whether they are connected at EHV or HV/LV.
Onsite generation (when self-consuming)	Inverse of transmission demand changes (as a saving on bills).	Inverse of distribution demand changes (as a saving on bills). These could vary depending on whether they are connected at EHV or HV/LV.
Large demand user	Charged for "wider" TNUoS charges based on demand during Triad periods	Distribution demand charges. These could vary depending on whether they are connected at EHV or HV/LV.

5.81. These differences are likely to be influencing users' investment and operational decisions. In some cases, this may lead to strong incentives to invest in a particular type of generation/demand side response solution, which can lead to adverse impacts on the system and ultimately consumers, where these decisions are being driven by differences in regulatory arrangements rather than differences in underlying cost drivers.

5.82. One way to address these risks would be full harmonisation, ie to fully align the approach for charge design across DUoS and TNUoS and across generation and demand. This would mean that one of agreed capacity charges, static volumetric time-of-use charges or critical peak pricing would apply for all user types across both networks.

5.83. There are, however, a number of reasons why this may not be desirable or feasible. Within this section we outline some initial thinking on where there might be arguments to maintain different approaches for charge design. In reaching decisions on the way forward, we will need to take these into account and weigh them against the potential distortions caused by not fully aligning approaches. We discuss differences relating to how locational cost models work for different types of user (particularly the split between EHV and HV/LV distribution-connected customers) in the Options for improving locational accuracy of distribution charges discussion note.

Differences in suitability of options for different user types

5.84. We outline below our preliminary considerations on how different charge design options may be more suitable for different types of user.

Agreed capacity charges

5.85. As described above, agreed capacity charges would mean that operational signals need to be sent through alternative approaches such as flexibility procurement or complementary options for access right choices. These may be more suitable routes for larger, more sophisticated users, at least if not facilitated by a supplier or intermediary, or enabled through automation. For example, many larger generators (over 100MW) are already active participants in the Balancing Mechanism, whereas it has only just been opened up for smaller users and it is not yet clear how many will participate.

5.86. Similarly, small users may find it more difficult to understand and engage with decisions on what level of agreed capacity they need, though suppliers or other intermediaries could help inform and explain these choices, managing some complexity on consumers' behalf. Automation technologies or services could also have a role.

5.87. We also note that, within the TNUoS application of agreed capacity for larger generators, there is an adjustment for generators' technology type and annual load factor in calculating their wider locational tariffs. Under a framework that treats generation and demand as equal and opposite, it might be appropriate to introduce similar arrangements for demand customers. However, we recognise it could be challenging to identify appropriate customer categories and the applicable annual load factors. We will consider the feasibility of this and the application to small generators as part of our further work.

5.88. A further issue with agreed capacity charges is how they are applied in areas where a user would receive a credit rather than a charge. In such cases, using an agreed capacity charge to determine the size of the credit risks incentivising parties to inflate their level of agreed capacity above what they will realistically use. To mitigate this risk, TNUoS credits to large generators are based on their maximum average output over three winter periods rather than on their agreed capacity. If that approach is used to calculate a standalone generator's credits, it could potentially mean they receive a different signal to generation co-located with demand (as if the site was still self-consuming rather than exporting it would be paying a charge based on its agreed capacity).

Critical peak pricing

5.89. Potentially, critical peak pricing may be more difficult for small users to understand. However, suppliers or other intermediaries could help manage this complexity on their behalf.

Static time-of-use volumetric charges

5.90. Compared to the above options, this is a potentially simpler framework for smaller users to be able to understand and engage with.

Differences in feasibility across transmission and distribution

5.91. We discuss the differences in feasibility across transmission and distribution charges in the Links Between Workstreams discussion note. However, when considering whether to align the arrangements between distribution and transmission, another factor we need to consider is whether it is proportionate, given the costs and uncertainty involved. This is one of the reasons we have decided not to review the TNUoS charge design for large generators within this SCR – we do not see significant problems with the current arrangements (having relatively recently reformed them through our Project Transmit), which would require consideration as part of our SCR, and so we concluded it would not be justified to review them again at this time.[43]

Section 7. Summary of preliminary views

Basic charging design options

5.92. As described at the start of this chapter, we have identified five basic options for charging design. These options were identified with reference to the approach being taken in other countries, academic literature and the current charging arrangements in Great Britain and each of them would provide benefits to the network by incentivising customer behaviour change. However, to determine the shortlist of options we will model as part of our impact assessment, which will help to quantify the potential benefits, we have been considering the matters described in this chapter to identify how well they reflect drivers of the network companies' costs, any feasibility limitations and other implementation issues. We note additional work will be need to determine the shortlist of options, including further work on any implementation challenges and identifying any unintended consequences of the different charging designs (eg if automation just results in peak shift, as devices respond to the peak price signals, and do not relieve network constraints).

DUoS charging design

5.93. Below we set out our preliminary views of how the options could be applied to DUoS charges, where it is possible to do so:

- **Agreed capacity** – analysis by the Cost Drivers subgroup indicated costs are driven by peak usage, rather than volumes consumed, which suggests that charges that are based on peak capacity may be more cost-reflective than a volumetric approach. However, given feedback that the DNOs may not consider agreed capacity, we will need to undertake further work in order to determine if this is a cost-reflective option. In addition, we note that it may be a significant administrative burden to agree and maintain capacities with millions of domestic customers, although this could be deemed by the supplier or DNO in the first instance. We will weigh up the risks and benefits of deeming capacity, which may not be aligned to each customer's actual network usage.

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[43] This does not mean changes cannot be considered as part of the code modification process. For example, we note the ESO has raised CMP317 in relation to EU regulation 838/2010: https://www.nationalgrideso.com/document/144516/download

- **Actual capacity** – as above, a capacity-based option may more closely align with the drivers of network costs, although this would be dependent on the granularity of charges (ie the alignment between a customer's peak and local assets) and the factors the DNOs consider when planning their networks. As with the agreed capacity option, we will need to undertake further work to understand the link between network planning and DUoS charges. In addition, the relative advantage of this compared to a volumetric time-of-use option is unclear, given there may be limited difference in customer response, where time bands are also applied to actual capacity. If we decided that the DNOs should continue to charge suppliers, based on their customers' actual behaviour, we would need to consider whether the benefits are significant enough to change from consumption to capacity-based charging.
- **Volumetric time-of-use** – volumes of energy consumed are not a key driver of costs (i.e. it is the usage at peak times that is the main driver) and so our preliminary view is that flat volumetric charges may not be the most cost-reflective option. However, we consider there may be still be reasons to continue applying time profiled volumetric charging, including that it is familiar to small users and there would still be opportunities to make it more cost-reflective by introducing seasonality or more locationally granular charges.
- **Dynamic charging** – may not be feasible by 2023, due to the extent of the network monitoring equipment that would need to be installed and connectivity identified to support it. In addition, issues with the ability to forecast market conditions, as identified in our discussion on SRMC in the Distribution Locational Charging Model note, also impact on whether dynamic charging is feasible. However, we will need to undertake further work to better understand the issues and identify whether arrangements could be built into the changes we make to improve how dynamic charges are later.
- **Critical Peak Rebates** – we will need to undertake further work to identify whether it is possible to implement this, as it may not require the same degree of monitoring as the dynamic charging options. However, there may still be feasibility issues, as a baseline needs to be established for each customer, in order to determine if they have changed their behaviour and are eligible for a rebate. We will also explore the benefits of hybrid agreed capacity and critical peak rebate option and consider if suppliers are better placed to design incentives that best engage their customers.

TNUoS charging design

5.94. For the TNUoS demand charges that apply to large users, our preliminary view is that the main options are between retaining a critical peak pricing approach (but making changes to address the current disadvantages identified with Triad) or moving to an agreed capacity approach. However, before making a decision, we will be undertaking further assessment with the ESO of these options and whether there are alternatives that may be more cost-reflective. For example, because the transmission owners plan their networks based on year round considerations, rather than just focusing on usage at peak, purely peak-based charging may not be the most cost-reflective option. As part of our ongoing assessment, we will consider applying time-of-use volumetric or actual capacity TNUoS charges (among other options) for small users. We will also undertake further assessment of whether there is value in applying these options for large demand users.

5.95. We recognise that a key consideration in our charge design decisions for DUoS and TNUoS demand charges and for TNUoS charges for small generators will be the extent to which any differences in approach risk distorting behaviour. We will consider this further in our next working paper.

5.96. A further key consideration is the degree that we think short-term operational signals to balance the system should be sent through charging signals or through access right choice and trading, and/or flexibility procurement by the ESO and DNOs. This is a key factor in guiding this choice between dynamic charges or agreed capacity charging. We discuss this further in our Links with Procurement of Flexibility note.

DUoS charging design – cross-cutting policy issues

5.97. We have also formed preliminary views on several overarching matters relating to the DUoS charging design framework:

- It is likely to be more cost-reflective to introduce a seasonal element into charging for HV and LV customers, given the initial evidence provided by the DNOs. However, we will need to determine the level of locational granularity that should be applied before being able to confirm whether there is a dominate season in each location.
- It may also be more cost-reflective if the time bands for high charge periods could vary across a DNO region. However, it will not be possible to identify how the time bands should vary, until the degree of locational granularity has been decided.
- As reactive power charges only apply to reactive power in excess of the power factor set out in the national terms of connection, we have not identified any evidence yet to suggest they should not continue under any changes to the charging structure. However, we have received feedback from stakeholders about the potential for reactive power to be a dispatchable product, which we will need to consider when making a final decision about reactive power charges. In addition, we have not yet formed a preliminary view on whether they should also apply to small users.
- We have not identified any compelling reason to change individual billing for small users, as suppliers have advised they receive separate consumption data that they can use. However, we will need to do further analysis to understand whether there is a need to implement individual billing to enable some charging design options.

Annex – Additional detailed on reactive power charges

1. Reactive power refers to power with no real power transfer, which is carried by an electrical current, as opposed to active power, which refers to real power transfer within an electrical current. The combination of reactive and active power is known as apparent power. The ratio of active power to apparent power is called the power factor and, can vary between zero and one (called a 'unity' power factor). Reactive power takes up capacity on the network, but it is not inherently 'bad', as it is necessary in order for active power to flow. However, if the power factor falls below what is required to transport active power (or the agreed level), then it is taking up capacity on the network without doing any 'real work' and so there may be a rationale for charging for the excess reactive power.

2. Under the current CDCM, half-hourly settled customers with current transformer meters (in Measurement Classes[44] C and E for settlement purposes) incur reactive power charges, once their reactive power exceeds 33 per cent of total active power. This is equivalent to an average power factor of 0.95 during the period, which is the power factor required under the standard national terms of connection. The purpose of the excess reactive power charges is to incentivise applicable customers to maintain a power factor of no more than 0.95 lagging.

3. In 2014, we approved[45] the introduction of two additional categories of DUoS charges for half-hourly settled domestic customers and half-hourly settled non-domestic customers with whole current meters (Measurement Classes F and G respectively). The charges for these two groups were set to minimise any bill disturbance when customers moved from non half-hourly to half-hourly settlement and, as such, they do not include separate capacity or reactive power charges. This means that, under the current charging arrangements,[46] not all customers face reactive power charges.

4. As part of the work undertaken by the Cost Drivers subgroup, they considered whether reactive power is a driver of network costs. The subgroup's conclusion was that, although there are not any examples of reactive power driving reinforcement costs, it is a component of overall network loading (i.e. it takes up capacity and so may contribute to the need to reinforce). However, the subgroup also noted that:
   - Charges would need to be set sufficiently high to incentivise customers with a poor power factor to take steps to reduce it, such as investing in power factor correction equipment.
   - If reactive power trading, which is currently permitted for transmission connected customers, was introduced at a distribution level, then they should be exempted from the requirement to pay reactive power charges.

5. Regarding the Cost Drivers subgroup's point about changes that could result in the opportunity for customers to participate in reactive power services, we note the ESO and UKPN's Power Potential project,[47] which seeks to create a reactive power market for generation, storage and aggregators. We therefore recognise there may be instances when it is may not be appropriate to always charge customers for exceeded reactive

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[44] https://www.elexon.co.uk/wp-content/uploads/2017/06/change_of_measurement_profile_class_v13.0.pdf
[45] https://www.ofgem.gov.uk/sites/default/files/docs/2014/10/dcp179_d_0.pdf
[46] Note that, under the charging design structure we approved under DCP268, which is expected to take effect from 1 April 2021, there are not any changes to which customers will incur reactive power charges.
[47] https://www.nationalgrideso.com/innovation/projects/power-potential

power. However, we also note that DCP22[48] was introduced to exempt a generator from reactive power charges, where they it has entered into an agreement with the DNO to adjust its reactive power, which means a framework is already in place that could be continued under any future arrangements.

6. In addition, we note that reactive power charges, if set cost-reflectively, may not be sufficient to incentive customers to reduce their power factor. This suggests that it could be more effective to manage customers with a poor power factor under their connection agreement, rather than applying reactive power charges. However, we understand that this could be significant capital investment for customers and, depending on the circumstances under which the excess reactive power has occurred (e.g. a short-term operational issue), it may not be proportionate to undertake investment to manage the issue. We are also mindful that, even if customers do not change their behaviour in response to a reactive power charge, it may be fairer that they pay for the impact on the network, rather than the cost being socialised across all customers, including those who have a power factor of no more than 0.95.

7. As reactive power charges are only applied to reactive power in excess of the requirements set out under the national terms of connection, our preliminary view is that they should continue to be paid, unless the reactive power is in response to a DNO request (consistent with the exemption introduced under DCP222). Given reactive power is complex to understand and recovers only a small amount of revenue, our preliminary view is that there may note a benefit in extending to small users. However, we will consider this further. We will need to undertake further work to determine whether it would be effective and proportionate for the DNOs to manage customers with poor power factors under their connection agreements.

[48] In August 2016, we approved DCP222, which amended the CDCM so that, where a HH metered generator has entered into an agreement to adjust its reactive power, it will be exempt from reactive power charges. The decision is here: https://www.dcusa.co.uk/Documents/DCP%20222%20Authority%20Decision%20Letter.pdf