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4th February 2019

Targeted charging review: minded to decision and draft impact assessment

Dear Andrew,

This response is on behalf of National Grid Electricity System Operator (NGESO) and is not confidential. In the context of electricity charging arrangements, we are responsible for setting Transmission Network Use of System (TNUoS) tariffs and recovering the costs of system balancing actions from all relevant network users. We are also the lead secretariat for the Charging Futures Forum (CFF) which has been established to help make charging more accessible.

We see the Targeted Charging Review (TCR) as a significant step forward for charging arrangements. We agree with the principles it sets out, the intention that these changes can deliver benefits to consumers and are supportive of creating a Balancing Services Use of System (BSUoS) task force which we will lead. We also welcome Ofgem's wide engagement through the Charging Futures Forum which has been well received by stakeholders and has helped to inform the debate. This engagement is essential, particularly for smaller parties which will be impacted by changes to the arrangements but don't have the capacity to follow these in detail, and to help manage investor uncertainty.

The answers to your questions are detailed in the Appendix, however we would like to highlight a few key areas.

We agree that moving to a year-round residual, rather than the current system of using triads, will remove distortions in demand charging as today some parties can easily avoid these charges. We believe that only demand users paying residual charges could reduce costs to consumers, due to only one risk premium being incurred rather than on both generation and demand. However, we must understand the impact to vulnerable consumers of making this change.

Whilst we agree that existing information should be used to categorise demand users, we believe that further consideration is required on how this will work in practice. We are concerned that there is scope for Line Loss Factor Classes (LLFCs) to change in future which may impact the chosen solution. Instead we suggest that using agreed capacity best reflects a consumer's use of the network, is less likely to be the subject of industry change and is difficult to avoid without physically changing the volume of electricity they can take from the system. This information already exists for the majority of large demand, and for smaller consumers a more generic fixed rate could be used.

We have heard concerns from our customers and stakeholders about investment uncertainty, for example charging embedded generators BSUoS came as a surprise to some as it wasn't seen as a prominent area of discussion in the CFF. We therefore think that a holistic implementation plan is needed across changes in the energy sector, with sufficient lead times, to allow parties to understand and react to the changes. This should include the implementation of the TCR, the Access and Forward-Looking Charges code review and our work, as set out in our road maps, to ensure embedded generators can participate in the same balancing markets as transmission connected generation. A holistic approach would be more equitable as parties would have access to the same revenue streams and pay the same charges, as well as only being impacted by one set of charging changes. When considering this alongside Ofgem's proposed implementation dates of 2021-2023, we feel that a 2023 implementation date is more appropriate.

We would like to reiterate our support for the principles set out in the TCR as it marks a significant step forward for charging arrangements. We look forward to working with both Ofgem and industry on the detail of how the TCR is implemented in practice and are happy to raise the supporting Connection Use of System (CUSC) changes. Please don't hesitate to contact harriet.harmon@nationalgrid.com if you wish to discuss this response in more detail.

Yours sincerely,

C McClay

Cathy McClay
Head of Future Markets

Appendix – answers to consultation questions

1. **Do you agree that residual charges should be levied on final demand only?**

We agree that residual charges should only be charged to final demand consumers under the principles of Ofgem's TCR. Residual charges by their very nature do not send a useful signal to generators about where to locate or how to operate. Where non-cost reflective charges are levied on generation, they can distort wholesale market prices as generators and suppliers may use risk premia to mitigate volatility in charges that they cannot easily predict under current arrangements. Therefore, end consumers may pay their own residual charges and the risk premia both their supplier and generator have levied on the same volumes against the same cost element. A move to levying residual charges only on demand removes some of this risk and should benefit the consumer overall.

We are concerned that there is the potential for avoidance of final demand charges at storage and generator sites, as well as final demands that are co-located or hold private wire arrangements with generator and storage operators. Any demands through a single connection point associated with a storage operator or generator may not attract appropriate residual charges for final demand that is also using that connection point, as there is no distinction in current metering and settlement arrangements. This would potentially allow final demand to utilise a storage or generation connection to avoid charges that they should otherwise have paid. Any solution that is taken forward to remove charges from intermediate demand will need to ensure that robust settlement and licensing arrangements are in place such that cost avoidance by sites with more complex setups does not take place.

2. **Do you agree with how we have assessed the impacts of the changes we have considered against the principles? If you disagree with our assessment, please provide evidence for your reasoning.**

We agree with the principles underpinning the TCR, but do not think that all of the elements of Ofgem's preferred approach accurately reflect the challenges of implementation, and we therefore question the extent to which it is proportionate.

Moving to an LLFC approach - which we have interpreted to mean using the 18 existing Distribution Use of System (hereafter 'DUoS') charging categories for Low Voltage (LV) and High Voltage (HV) demand consumers to create residual charging – does not, in our view meet the requirement of proportionality. We expand further on this point in our answer to Question 9 of this consultation.

We do agree that it is important to remove harmful distortions and consider that the move to a 'year-round' residual charge is a good way to support equity in arrangements. We think, however that in order to deliver fairness, residual charges based on agreed capacity and Measurement Class would be more appropriate. We provide further detail on how this would work in practice in our response to Question 9 of this consultation.

We are mindful that although we do not necessarily agree with all of Frontier Economics' analysis, the output indicates that the very smallest consumers in the market will be detrimentally affected by these changes. Within this category there will undoubtedly be a mix of sites, from second homes and seasonal usage through to very small domestic properties. We believe that it is important to ensure that the fuel poor and the otherwise most vulnerable consumers are protected from undue cost increases. We believe that any cost increases for those already considered vulnerable is unlikely to meet the principle of fairness or equitability and that this area should be reviewed further.

3. For each user, residual charges are currently based on the costs of the voltage level of the network to which a user is connected and the higher voltage levels of the network, but not from lower voltage levels below the user's connection. At this stage, we are not proposing changes to this aspect of the current arrangements. Are there other approaches that would better meet our TCR principles reducing harmful distortions, fairness and proportionality and practical considerations?

This statement is true only of DUoS charges, not of TNUoS charges. There is no link between TNUoS residuals and voltage, except that which would be introduced through the use of LLFCs to drive TNUoS Demand Residual charging per Ofgem's preferred approach.

Whilst we understand Ofgem's view that there is no current need to change this aspect of arrangements (DUoS charges based on voltage), we are particularly mindful of the ongoing Access & Forward-Looking charges work which may move the connection boundary for Distribution connections and may make significant changes to arrangements for consumers charged through the Common Distribution Charging Methodology and EHV equivalent (hereafter C/EDCM). There is a risk, therefore that segmentation using DUoS information would create temporary categories.

We believe that it is not appropriate to look at the costs associated with different voltage levels until such time as there is greater clarity on the extent of the changes the review of forward-looking signals and connection regimes will bring.

4. As explained in paragraphs 4.41, 4.43, 4.46, 4.49, 4.80, we think we should prioritise equality within charging segments and equity across all segments. Do you agree that it is fair for all users in the same segment to pay the same charge, and the manner in which we have set the segments? If not, do you know of another approach with available data which would address this issue? Please provide evidence to support your answer.

In principle, yes, we agree that all users in the same segment should be liable for the same charge and that there should be equity across segments, such that the charges levied do not favour any particular category of consumer.

We understand Ofgem's desire to create different charges for domestic and non-domestic users, and in principle support it, although we are mindful that such users are not always significantly different in their connection or utilisation size. We believe it is important to have sufficient categories for equity to be possible, without creating so many that the charging regimes become overly-complex and understand therefore the view that segmentation by existing industry data is appropriate. We cannot however agree that segmentation by DNO-specific information, like voltage level is appropriate for TNUoS charging.

In specific relation to the manner in which the segments have been set: in our view the analysis conducted by Frontier Economics does not use reasonable assumptions for the annual consumptions of the consumers it seeks to categorise. We note that there is a significant gap between the 25MWh annual consumption of a non-half hourly (NHH) small business and the 5GWh of the next largest category of non-domestic user. Having spoken to electricity suppliers, we understand that there are thousands of businesses which fall within this large range, and therefore the analysis which indicates the notional changes to charges is probably not representative of a great many users and the costs they may incur. We believe that 25MWh is a low estimate and that 5GWh is too high – in our view a typical half hourly (HH) consumer would consume around 0.7-1GWh.

Separately, but in addition, the same consumption threshold of 5GWh per annum. is used as the basis for the assessment of the changes to Extra-High Voltage (EHV) consumers. This threshold does not treat an EHV site any differently to a HH consumer connected at any other voltage level. To the extent that Frontier have therefore not differentiated between voltages of connections for HH consumers, we are of the view that further information would be needed to support a view that segmentation based – in whole or in part – on voltage is appropriate.

Aside from any consideration of the consumption thresholds used for the analysis, we are mindful of the potential for unintended consequences to the relative complexity of market arrangements. There are currently 18 DUoS tariffs for demand in the CDCM. Proximity to a DNO substation and the voltage of connection are, we believe, important considerations for a DNO when calculating and apportioning Use of System charges. We appreciate that it may seem relatively straightforward, therefore to use one common set of user categories across DUoS. We are mindful, however of the complexity that such a solution would inadvertently create in TNUoS arrangements, which we explain further in our response to Question 9 of this consultation.

5. Do you agree that similar customers with and without on-site generation should pay the same residual charges? Should both types of users face the same residual charge for their Line Loss Factor Class (LLFC)?

Yes, we agree that similar customers with and without on-site generation should pay the same residual charges, but we do not agree that they should pay based on their LLFC or that their total consumption needs should be treated in the same way.

We consider that charges should not be calculated based on consumption that the user with on-site generation has avoided drawing from the network. We note the use of the Future Energy Scenarios July 2018 gross data in Frontier Economics' assessment and believe this suggests that demand which is met by behind-the-meter generation, as well as that which is imported from the network would be chargeable or at least included in the calculation of the charge. We would welcome Ofgem’s view on whether this is the intent.

The use of behind-the-meter generation is a form, in our view, of demand side response and is no different than choosing to consume less; we do not believe that behind-the-meter generation and standalone embedded generation are sufficiently similar to merit similar treatment in charging regimes. We note that during the April 2018 Judicial Review of The Authority’s decision to approve CMPs 264 and 265, both we, as an interested party, and Ofgem rejected the Claimants’ view that behind-the-meter generation and embedded generation were similar to the point that the decision was discriminatory. Whilst we agree with Ofgem’s view that sites should pay the same charge irrespective of the presence of on-site generation, we would like to understand more about the potential for alignment between behind-the-meter generation and standalone embedded generation.

We have suggested an alternative, in our response to Question 9 of this consultation, of charging based on agreed Maximum Import Capacity (per DCUSA/NTC, and hereafter ‘MIC’). We believe that irrespective of whether a site has behind-the-meter generation, charging on capacity leads to users paying based on their occupancy of the network – if a site ‘books’ 500kVA with the DNO then whether it uses on-site generation or not, the site would be charged for that 500kVA. We believe that this is more equitable as each user is charged based on how the network has been developed for their connection.

6. Do you know of any reasons why the expected consumer benefits from our leading options might not materialise?

Without being able to test the models utilised by Frontier Economics in their assessment, we are unable to validate their conclusions, however, we would suggest a degree of caution in accepting the results of their analysis as a likely outcome.

The annual consumption thresholds they have used are, we believe, not representative, and are likely to distort the results of the analysis such that the benefit to smaller users, on a per-MPAN (Meter Point Administration Number) level, is exaggerated. We have confirmed our view of typical consumption values with suppliers and are not confident that the site-specific benefits are accurate. Frontier's assumption that a typical HH consumer uses 5GWh per year and is avoiding residual costs leads to a relatively high notional benefit for smaller consumers, based on that 5GWh. We do not, however, believe that the typical consumption figures listed in Frontier Economics’ assessment are correct, and therefore consider that the benefits at site level are likely to be overstated.

We have separately submitted some further information to Ofgem in response to Question 10 which we feel could also have a bearing on the benefits case, but from a more ‘whole system’ perspective than at an individual consumer level. This information has been submitted under confidential cover as it relates to wholesale market price assumptions. We would be happy to discuss the response to Question 6 and to Question 10 with Ofgem and Frontier Economics and are keen to assist in evaluating consumer benefits where we can.

7. Do you agree that our leading options will be more practical to implement than other options?

Yes, although we do not agree with the preferred approach of LLFCs. We agree that a ‘fixed’ charge is more practical than any ex post adjustments based on site-specific peaks, but believe that there is a better solution to be found than LLFCs, from both a practicability and a proportionality perspective.

LLFCs are indirectly under review owing to Ofgem’s work on Access & Forward-Looking charges, which will see significant amendments to the DNOs’ charging regime. Assuming that some form of categorisation is still in place once that review has concluded, we are concerned that it is relatively easy for a consumer to move between LLFCs. Changes in LLFCs are not uncommon in the LV and HV markets and we do not believe it is appropriate for a consumer’s TNUoS charges to change as a result. We have provided further detail on this point, and on how our suggested MIC-based approach would work in practice in our response to Question 9 of this consultation. We believe this approach still achieves some degree of segmentation by user category (domestic, non-domestic and some element of size) without introducing complexities which risk creating barriers to entry for smaller Suppliers.

For implementation of a MIC-based approach, we see it as reasonable to calculate only 14 HH locational tariffs and have the NHH charge (p/kWh) used as a ‘residual’ in itself – the revenue that cannot be recovered through the 14 HH locational plus residual should be assigned to NHH charges to help create predictability and ensure recovery of Transmission Owner (TO) revenues.

8. Do you agree with the approaches set out for banding (either LLFC or demanding for agreed capacity)? If not please provide evidence as why different approaches to banding would better facilitate the TCR principles.

No, we do not agree with LLFC, per our responses to previous questions. In terms of capacity, we think it is inappropriate to deem capacity for sites without a MIC. Deeming a kVA value for a property creates an arbitrary distinction between different sites and risks creating a system where consumers who live in one particular region are disadvantaged over another. We note the varying approaches DNOs took to ‘deeming’ capacity for certain sites during implementation of P272/P300/P322A and are keen to avoid inconsistency in arrangements. Even if each DNO did follow the same approach to deeming a capacity, we see this as no more accurate than using profile class, estimated annual consumption or any other assumption-based categorisation method.

We do not believe that a MIC and Measurement Class approach requires any kind of banding; charging on MIC provides equal arrangements, in that two sites with the same capacity would pay the same charge, as well as equitable charges in that larger network users would pay more than smaller users.

9. Do you agree that LLFCs are a sensible way to segment residual charges? If not, are there other existing classifications that should be considered in more detail?

As stated in our previous answers, we do not agree with the approach using LLFCs due to the reasons set out below.

Nomenclature:
The use of the term ‘LLFC’ in both Ofgem’s consultation and Frontier Economics’ assessment is not consistent with the industry-standard definition. The LLFC is the specific alpha-numeric value assigned to an MPAN, illustrated in its ‘top-line’. What we believe Frontier and Ofgem mean is the 18 CDCM demand DUoS bandings. We are mindful that not every respondent will have interpreted the term in the same way and that therefore Ofgem may receive responses predicated on a variety of understandings. This is not consistent with industry having a common view of Ofgem’s proposals or the likely repercussions for consumers and we are concerned at the potential for this TCR to proceed to Authority decision without all industry parties fully understanding the proposals. We will refer hereafter to the 18 DUoS bandings, in line with our interpretation.

Linkage:
We are not clear on the rationale behind using information about the DNO network to drive transmission charges. We are also unclear on the link between the voltage of connection at DNO level and the extent of a consumer’s transmission charge. We accept that there are instances where DNO works requires transmission investment; this process is catered for under the CUSC at present. It is not the case, however, that every time a consumer connects to the DNO’s network the transmission network requirements change.

We would appreciate further detail from Ofgem and/or Frontier as to the underlying reasons for creating a link between DNO voltage level and TNUoS. Without further detail, we believe that it will be difficult for users and consumers to understand why proximity to a DNO substation drives TNUoS contributions.

Moving between bandings:
LV and HV LLFCs in their true form are changed by DNOs as part of either their business as usual processes (validation and/or rationalisation), or at the request of a consumer. It is not unknown for consumers to change LLFCs and therefore DUoS bandings within-year. Where a consumer can see a clear financial benefit in changing their LLFC (ie in order to move to the next lowest DUoS banding), it is likely that they will engage their supplier and DNO to facilitate the change. Whilst we understand that each request would likely be assessed on a case-by-case basis, we consider it too easy to move from one DUoS banding to another and are concerned that consumers who are on the cusp of one or the other could ‘game’ the boundary to reduce their charges. We suggest it would be appropriate to look at the number of LLFC changes which led to a DUoS banding change over the last charging year before developing this option further.

Tariff volatility:
We believe that there is an increased risk of forecasting error and therefore over- or under-recovery of TNUoS owing to the increased number of categories for which we will need to forecast volumes.

Under an LLFC approach, we will need to forecast aggregate gross volumes in 18 categories, plus those for EHV and transmission-connected demand. If each category has a different tariff rate for its residual charge, and the forecast volume in any category is for any reason different to outturn, the total recovery for that category will be either a shortfall or an excess; in either event, the total revenue collected through TNUoS would not match the combined Maximum Allowed Revenues for each TO. Any over- or under-recovery will then need to be factored into future years' TNUoS through the 'K factor' within our licence - this is likely to increase the relative volatility of TNUoS on a rolling basis and may increase the cost of us managing this risk. We understand from Suppliers that tariff volatility is managed through the use of risk premia in consumer pricing and therefore consider that an increase in volatility could directly affect consumer cost.

Complexity: It is not currently clear how Ofgem see the Transmission Demand Residual (TDR) being calculated and applied if DUoS bandings were used. As the ESO, we currently create 28 demand tariffs (one for HH, one for NHH per GSP Group) a single £/kW HH residual, and an Embedded Export Tariff. There are also just under 300 individual generation tariffs to be calculated each year.

We believe that there are two possible outcomes of using the DUoS bandings. Either:

1. we calculate 28 demand locational tariffs, and 18 residuals, which would be calculated based on total GB volume per DUoS banding (such that each GSP Group had its own locational but a generic residual); or
2. we calculate 28 demand locational tariffs, and 252 residuals, which would be based on volume per DUoS banding per GSP Group (such that each GSP Group had its own specific locational and residual)

We assume that under the principle of practicability, the latter option is not the intent but would welcome Ofgem's confirmation.

Irrespective as to whether using DUoS bandings leads to 46 tariffs or 280, we believe that the use of DUoS bandings introduces more complexity than alternative arrangements, as significant changes to systems and codes would be required to facilitate our receipt of the relevant data. The scale of the system changes required by all parties, but in particular by NGESO as we do not currently use these categories in any form, will create additional IT costs for all participants, leading to increased costs to consumers. We can share separately an early estimate of associated CAPEX/OPEX costs to aid in Ofgem's assessment of this option.

Inconsistency:
It is proposed that all EHV and transmission-connected demand would be categorised together. We do not believe that this supports grouping similar types of users into charging bandings. Some EHV and transmission-connected demand users are very similar, and their arrangements are perhaps on the cusp – they could have connected either side of the boundary. Some EHV and transmission-connected demand users are multi-national firms with tens of thousands of employees, whereas others are small businesses with very high consumption. The similarity between them is not immediately apparent and grouping them into one category with one charge will likely be inequitable.

Simpler alternatives:
We feel that capacity is worth further consideration

By way of background: Under the DCUSA and National Terms of Connection, a HH consumer may agree a MIC with their DNO. This MIC is then directly chargeable. The supplier will receive a DUoS charge for that specific MPAN, which will list MIC charges as a separate line item (£/kVA). Some HH consumers are still, however, invoiced as though they were NHH. There was a suite of cross-code modifications to facilitate the transition of MPANs out of Profile Classes 5-8 into Profile Class 0 (HH), one of which enabled a subsection of HH sites to avoid the need to agree a MIC and therefore to avoid a specific MIC £/kVA charge. This ability stems from Measurement Class – a way of categorising different premises for the purposes of settlement.

Practicalities: Residual charges could be levied against MICs for sites that have them. It is feasible for a DNO to provide us with the aggregate contracted MVA in its GSP Group to form the charging base (either through Week24 data or another means). Each GSP Group would continue to have a locational demand charge, and then a £/kVA residual for sites with MICs. For sites without a MIC, we would suggest charging by Measurement Class.

Measurement Classes currently enable sites to be split based on size and type of consumer, with different categories for HH sites with larger and smaller meters (Current Transformer, hereafter 'C/T' vs. Whole Current, hereafter 'WC'), as well as larger and smaller utilisation (>100kW vs. <100kW). It is also possible to differentiate between domestic and non-domestic, and to facilitate separate arrangements for unmetered supplies (UMS), where consumption can range from a very small village's Christmas lighting through to a network of mobile phone masts. We, and all DNOs are already in receipt of data split by Measurement Class. Suppliers already use this information to drive consumer pricing and there are therefore far fewer system changes needed across industry for implementation. In practice, a residual charge levied at a Measurement Class level would create separate residual charges for NHH, UMS, Non-Domestic HH >100kW, Non-Domestic HH<100kW (C/T), Non-Domestic HH<100kW (WC) and Domestic HH.

Equity and equality: If Ofgem wanted to segment sites with MICs it could choose to do so by creating ranges (i.e. MIC of 100-450kVA pays £x/kVA, MIC of 451-600kVA pays £y/kVA) although we do not think this would be necessary. There would, even without ranges, be equity within arrangements as all users would pay according to their capacity, and equality in that every consumer with the same capacity would pay the same value. Creating further segmentation would, we believe, lead to the issues we have highlighted in the 'tariff volatility' part of this answer.

We believe that there is already an element of segmentation present within Measurement Classes however if Ofgem wanted further segmentation of, say the domestic market, it could choose to introduce a small number of new classes; as Measurement Class is an existing dataset, it may be simpler to add a new category to existing systems than to change what a particular dataset (i.e. LLFC) is used for.

Ability to avoid: MICs can be reduced or increased. To ensure that a consumer could not avoid a residual charge, the solution for residual should be based on industry data that is not easily changed. We believe that MICs meet this requirement. If a consumer has a MIC of, say, 200kVA and wants to reduce it to pay smaller residual charges, they must approach their DNO and accept a lower level of maximum consumption.

The DNO will not allow a consumer who clearly requires 200kVA to reduce their MIC. Where that consumer actually only ever utilises 150kVA, the DNO may permit a reduction, which then frees up capacity on the network. If that consumer, having moved to 150kVA then breaches their MIC, they are charged Excess Capacity Charges through their DUoS invoice on the incremental difference – following the implementation of DCP161 these charges are significantly higher than the charge that would have been levied against the MIC had it remained unchanged. There is a clear financial disincentive to artificially reduce one's MIC to avoid MIC charges, and the process between consumer and DNO does not allow it in instances where it is clear that the consumer will require a higher MIC in the future. If a consumer did request a MIC increase later on, they would likely need to pay for the relevant works to enable it.

It is not easy to move between Measurement Classes. At the moment, all NHH MPANs are Measurement Class A. As they transition to HH settlement, they will be placed into one of three <100kW Measurement Classes (in brackets): Non-Domestic with C/T metering (E); Domestic with either C/T metering or WC metering (F); and Non-Domestic with WC metering (G). Under our proposal, the sites moving into E would be charged on their MIC. Sites in F and G could then face different charges. As Classification of Premises (per SLC6 of Supplier Licence) is used for categorisation, it is not possible to easily move from one Measurement Class to another. In order to move from non-domestic to domestic, the supplier would have to be satisfied that consumption at the premises was wholly or mainly used for domestic purposes. The consumer's prices, rights and obligations and contractual terms would all change as a result and any invoices would be in the name of a natural person rather than a legal entity and it is therefore unlikely that a business would seek to gain domestic classification. If a site in Measurement Class E wanted to move to Measurement Class G, it would have to change its entire metering setup, at a direct cost. We are not sure how likely it is that many consumers will take such drastic steps to avoid the incremental difference in residual charges.

10.Do you agree with the conclusions we have drawn from our assessment of the following?
a) distributional modelling
b) the distributional impacts of the options
c) our wider system modelling
d) how we have interpreted the wider system modelling?
Please be specific which assessment you agree/disagree with.

We have submitted separately, under confidential cover (owing to wholesale price assumptions), the specific areas where we feel further information would be useful in our assessment of the modelling undertaken by Frontier Economics.

11.Do you agree with our proposed approach to the reform of the remaining non-locational Embedded Benefits?

We welcome Ofgem's decision to launch a BSUoS task force to assess the extent to which there are forward-looking signals to be found within BSUoS, and to consider whether and how those should be drawn out.

We do think, however that the work of this task force should be concluded prior to any changes being made to the categories of user liable for BSUoS. If the overarching intent is to have residual charges paid by demand only, and the task force is yet to determine the extent to which any of the components of BSUoS could be labelled as residual, it is premature to change arrangements now such that embedded generators become directly liable for BSUoS.

In addition, we believe that unless the BSUoS charging methodology is changed it is not appropriate to differentiate between 'final' and 'intermediate' demand for the recovery of BSUoS costs.

Equally, from the BSUoS workshops that we ran in October 2018, we consider one of the key questions for the task force to be whether BSUoS should remain a half-hour specific charge, or whether there are elements which could be year-round. We believe this follows directly from the assessment as to whether there are residual and forward-looking elements. If the outcome of the task force is a change to the period over which BSUoS is calculated or charged, then a move to charging on gross consumption now risks layering change upon change. We believe it is more appropriate to wait until the task force has concluded and answered questions relating to residual and forward-looking charges, as well as the extent to which reform of the time period over which BSUoS is calculated is needed, before making significant changes to both how and to whom BSUoS is charged.

12.Do you agree with our proposal not to address any other remaining Embedded Benefits at this stage? Which of the embedded benefits do you think should be removed as outlined in xx? Please state your reasoning and provide evidence to support your answer.

As we have stated in our answer to Question 11, we believe that there should not be significant changes to charging arrangements in BSUoS until the results of the task force are known. As Ofgem has indicated in the consultation, we are currently drafting a CUSC Modification Proposal to adopt the Authority and CMA 'broad' interpretation of European Regulation 838/2010 Part B into the charging methodology. This modification will also (subject to compliance with the relevant regulations) through its implementation achieve a Transmission Generation Residual (TGR) of £0/kW.

13.Are there any reasons we have not included that mean that the remaining Embedded Benefits should be maintained?

Per our previous answers, we consider that no changes should be made in advance of the conclusion of the BSUoS task force.

14.Do you agree with our proposed approach to transitional arrangements for reforms to: a) transmission and distribution residual charges b) non-locational Embedded Benefits? Please provide evidence to indicate why different arrangements would be more appropriate.

Overall, our view is that it is better to align changes under both Significant Code Reviews and changes to the balancing markets – we think all change should be delivered with an effective date of 1 April 2023. This gives all parties sufficient time to make changes to their systems/processes, for suppliers to make appropriate changes to contractual terms/pricing, for generators to rebase their cost assumptions and for smaller generators and Virtual Lead Parties to be able to participate in all relevant markets.

We do not believe that changes to demand residual charges can be – or should be – implemented on a transitional basis and would recommend a 'big bang' approach. Depending on the scale of the changes, we may need >12 months between decision date and the start of the first charging year in which the changes would apply.

For changes to the TGR, we believe a phased approach to £0 is feasible, starting in April 2021 subject to compliance with Part B of EU Regulation 838/2010. Although we understand Ofgem's preference to align all changes we are concerned that without earlier changes to the TGR we may breach the limit specified in the regulation in 2022. Taking forward a phased implementation would reduce this risk as well as signalling clearly to generators the scale and likely outcome of the change.

We do not support Ofgem's approach to BSUoS reform at this time however, were arrangements for embedded generation to change, we would recommend – per CMPs 264 & 265 – a transition period before the full extent of the changes in BSUoS took effect.

We note that the Access & Forward-Looking Charges review is proposing to examine the extent to which embedded generators should pay locational generation TNUoS charges. To the extent possible, before any charges (BSUoS or TGL) are levied to smaller generators, we believe it is crucial that Project TERRE and Wider BM Access, as well as access to all markets are in place such that embedded generators have access to the same revenue streams as their transmission-connected counterparts. It is essential that we avoid a situation where we (as industry) are charging the smallest generators in a similar manner to the largest, without affording them access to the same markets and same income opportunities.

15.Do you agree with our minded to decision set out? If not please state your reasoning and provide evidence to support your answer.

We fully support Ofgem's intent and the principles set out in the TCR. As set out in our response, whilst we agree that demand should be charged the residual element of use of system charges, and that that element should be unavoidable, we have concerns over the proposed use of LLFCs. In addition, we believe further consideration is required on the timings for implementing the TCR alongside the Access and Forward-looking charges review and our work to ensure embedded generators have improved access to balancing markets.

16. For our preferred option do you think there are practical consideration or difficulties that we have not taken account of? Please provide evidence to support your answer.

Yes, we have outlined these considerations in our response to Question 9 of this consultation.