Jon Parker
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10 South Colonnade
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London

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Dear Jon

Getting more out of our electricity networks by reforming access and forward-looking charging arrangements

RenewableUK and Scottish Renewables welcome the opportunity to respond to the *Getting more out of our electricity networks by reforming access and forward-looking charging arrangements* consultation issued on 23 July 2018. We support Ofgem's approach to the Charging Futures programme – collaborating with industry at the early stages of the development of this workstream. We encourage Ofgem to continue to engage with the wider industry as the Charging Futures work goes forward into subsequent stages.

Scottish Renewables is the voice of Scotland's renewable energy industry, working to grow the sector and sustain its position at the forefront of the global clean energy industry. We represent around 250 organisations working across the full range of renewable energy technologies in Scotland and around the world, from large suppliers, operators and manufacturers to small developers, installers and community groups, and companies right across the supply chain.

RenewableUK is the trade and professional body for the wind, wave and tidal energy industries. It promotes the deployment of clean energy in a smart energy system, increasing overall awareness of the UK's energy transition - from fossil fuels to renewable sources. Formed in 1978, and with more than 400 corporate member companies, our members employ a quarter of a million people and will invest more than £15.6bn in UK infrastructure between 2016 and 2021 – over 90% of which will flow to regions outside of London and the South East. In 2017, 28.8% of the UK's electricity was generated from renewable energy sources. 46% of this was generated by onshore and offshore wind, which provided 13.2% of the UK's electricity needs.

Both our organisations are committed to developing the UK's energy system to support greater use of renewable generation, in line with our carbon targets, and to bring more, cheaper, clean generation onto the system, in line with the government's ambitions. It essential that the reforms the to the charging and access regimes support these ambitions and that they consider the impact of changes on the whole system, creating a level playing field for all sizes of generation, whether connected at the transmission or distribution level, while delivering on climate goals. Ofgem must avoid de facto support for larger thermal generation, and ensure that a whole-system approach, that delivers best value for the consumer, is established.

As ever, our response is developed with our members, we would be happy to discuss any of it with you.

Yours sincerely,

Jenny Hogan

Deputy Chief Executive

Scottish Renewables

Barnaby Wharton

Head of Policy

RenewableUK

Question 1: Do you agree with the case for change as set out in this chapter? Please give reasons for your response, and include evidence to support this where possible.

AND

Question 2: Do you agree with our proposal that access rights should be reviewed, with the aim to improve their definition and choice? Please provide reasons for your response and, where possible, evidence to support your views.

We agree that there is a strong case for change in relation to distribution network access arrangements – which we consider critical to enable the transition to a more flexible and smarter energy system. We have long been concerned with the simplistic nature of distribution 'flexible connections'; the lack of investment signals associated with an uncompensated, unlimited and often unrecorded constraint. Further, we welcome the opportunity for further network access options.

However, we would like to highlight that the proposed changes set out in the consultation documents do not align with wider government policy objectives, nor do they truly reflect whole system costs. The indicative network charging proposals are likely to disproportionately impact on low-carbon, low-emissions generators and create, in effect, they are likely to unduly favour carbon-intensive, fuelled generators. We consider that the proposals do not reflect the wider societal cost of these fuelled generators, including the costs of increased air pollution and carbon emissions.

We are concerned that regulatory change through the Charging Futures work, particularly in the context of wider regulatory/policy change, could increase uncertainty/risk for projects – and potentially therefore sit in opposition to government and industry objectives surrounding clean growth. We are concerned that, when combined, these proposals could reduce investor confidence and increase the cost of investment. Risk from these proposals needs to account for the combined effect of:

- Major recent charging changes – P350 (transmission losses), DCP228 (DUoS time of use tariffs) and CMP264/265 (embedded export triad payments).
- Other major ongoing change processes – Targeted Charging Review, RIIO-2 and Open Networks / DSO transition.
- Potential future changes that Ofgem have highlighted – BSUoS.

These changes are in the context of, and compounded by, wider policy change including the proposed closure of the FiTs scheme, recently consulted on by government.

Going forward, this increase in investment risk could be translated into higher prices for consumers through several avenues:

- Reduced/slower delivery of subsidy-free generation to market.
- Increased transmission constraint costs due to delay in delivery of subsidy-free projects as the suite of projects available for bid-off actions will remain dominated by pre-existing projects.
- Reduced competition within wholesale markets.
- Increased strike prices within future Contracts for Difference rounds.
- Increased capacity market prices through delayed deployment of subsidy-free low-carbon generation to market.
- Reduced deployment of further DSR/flexibility due to network charging uncertainty.

Therefore it is vital that any detailed proposal which results from this work is supported by a whole-energy-system cost-benefit analysis, which includes consideration of the impact on emissions and the UK's ability to meet decarbonisation targets.

Question 3: Specifically, do you have views on whether options should be developed in the following areas as part of a review? Please give reasons for your response, and where possible, please provide evidence to support your views:

a) Establishing a clear access limit for small users, with greater choice of options (as considered under b) and c) below) above a core threshold – do you agree with our proposal in paragraphs 3.5-3.10 that this should be considered? Do you have views on how a core threshold could be set?
b) Firm/non-firm and time-profiled access – do you agree with our proposal outlined in paragraphs 3.15-3.21 that these options should be developed?
c) Duration and depth of access, discussed in paragraph 3.25-3.32 - would these options be feasible and beneficial?
d) At transmission or distribution in particular, or are both equally important – as discussed in this chapter?

a) **Core threshold** - we agree a core threshold should be within the focus of future work under the proposed scope. However, the difference between fuse size at 100A leading to a theoretical import or export capacity of 23kW against an After Diversity Maximum Demand of close to 2kW could cause significant forecasting issues for DNOs. Thus, we are concerned that setting a core threshold would be difficult.

b) **Firmness** – we consider that the definition of 'firmness' of access rights needs to be addressed as a matter of priority and included in the baseline scope for any work going forward. This is particularly an issue at distribution. Currently, the lack of clear definition around distribution network access rights for 'standard' connections creates distortion across the industry. Investment risk costs are higher for distribution connected projects due to the unspecific nature of access rights. It is normal practice for DNO-generator connection agreements to include vague clauses regarding firm/unfirm, de-energisation, constraint or curtailment. We note that the National Terms of Connection (Clause 5 in particular) set out sweeping rights for the DNOs to de-energise generation[1]. These unquantified (and largely unquantifiable) network unavailability risks for distribution connected generation increase the overall investment risk/cost for these projects.

We fully support a review of the risks associated with 'flexible' connections, including a cap on generator constraint. Currently all the risk associated with network unavailability rests with the generator, even though DNOs are able to best manage these risks. Some form of cap of commitment ahead of time to network availability would better allocate the risk to the DNOs.
Time-profile – the determination of 'seasonal' and 'off-peak' access products will be difficult to determine – requiring significant network analysis to understand what parts of the day/week/year are defined as off-peak as this will vary across different parts of the network. We see little value in such access rights at present.

c) **Short term access rights** – we consider that there is little value in developing a range of short term access rights, as energy investments are long term. Further, the short-term access products available for transmission connected generators are poorly utilised. In addition, the concept of short-term access rights has little meaning or value without more definition around long term access rights and obligations.

[1] http://www.connectionterms.org.uk/

However, for continued investment in new generation capacity there needs to be long term access products that last for at least the term of the project (20-25 years), with stable and predictable charges and network availability.

Long term access rights – we do not agree that long term access products (compared to current ever-green access arrangements) will reduce risks/costs and the added complexity may then result in higher costs for consumers. However, we do consider that there is value in applying utilisation criteria within connection agreements for generators and other large users to ensure that network capacity isn't sterilised by users no longer using/needing it (eg 'use it or sell it back', see answer to Q5c). Generators with evergreen access rights would likely plan for life extension and potential re-planting of existing sites. This would lead to efficient use of existing assets, and when combined with a 'use it or be reimbursed for it' set of principles would see that existing grid connection assets are unlikely to ever become stranded.

Depth/local access rights – we support further investigation into the potential value of access rights that are limited to specific networks/geographical areas, given the future potential for local energy systems and peer-to-peer trading to potentially include larger generators. We are concerned that the benefit of connection to broader grid could be undervalued and could be inconsistent with EU network codes. We would support greater analysis on the benefits local access arrangements could bring across both transmission and distribution.

d) It is important regarding whole-system impacts to consider whether changes, especially fundamental changes, would introduce a distortion if not applied across both the Transmission and Distribution networks. The answer may not always be the same for each issue identified.

Question 4: Do you agree with the key links between access and charging we have identified in table 1? Why or why not? Do you think there are other key links we have not identified? Where possible, please provide evidence to support your views.

Establishing a defined concept of 'firmness' would enable constraints to be properly recorded. This would enable better network development and also cost-benefit analysis which would establish whether network reinforcement to make existing connections more 'firm' would be better value for money for consumers than constraint payments.

Question 5: Do you agree with our proposal that targeted areas of allocation of access should be reviewed? Please give any specific views on the areas below, together with reasons for your response. Where possible, please provide evidence to support your views:

a) Improved queue management as the priority area for improving initial allocation of access, as outlined in paragraphs 3.41-3.44?
b) Not to consider the potential role of auctions for initial allocation of access as part of a review at this time, as discussed in paragraph 3.44?
c) To review the areas outlined in paragraphs 3.45-3.48 to support re-allocation of access?

a) We support further work on queue management arrangements. We would like to note that both ENA's Open Networks project and National Grid have already started work to address issues with queue management processes across transmission and distribution.

b) Agree with Ofgem that auctions should not be considered for initial allocation of network access.

c) We consider that there is a good case for reviewing the current arrangements for the re-allocation of access. We agree that network access conditions should include new conditions that place more emphasis on users' continued need for network capacity to avoid capacity hoarding. We believe this would help to reduce network costs – allowing network assets to be best utilised. However, we consider that the test to determine whether capacity is being used may be difficult to establish clearly and fairly. We are also concerned that the access rights reallocation process will not be transparent or equitable.

   We support further work which would determine the usefulness in practice of 'use it or lose it' principle. We caution that 'use it or sell it' would inevitably create problems with capacity hoarding and would inevitably create problems with capacity hoarding and the buying up of capacity prospectively with the intention of selling it on profit at a later date. The consumer would ultimately pay more than necessary in such a market.

   There are few clear examples of reallocation access rights from large users in constrained parts of the network. Before the introduction of CMP192 user commitment, National Grid held a 'TEC amnesty' in the north of Scotland. This process resulted in some connection agreement terminations which in turn resulted in changes to the required suite of reinforcements required to connect remaining contracted customers. This allowed some generators to have the opportunity to advance their connection date. However, without a clear set of rules outlined (for example in the CUSC) it was impossible for contracted generators or third parties to independently determine what the impact of this 'released' capacity was and/or validate the fairness of how the 'queue' was subsequently managed. Therefore, we consider that network access 'reallocation' processes need to be reviewed and considered to ensure best system outcomes.

   Increasing the ability for network users to trade capacity may increase capacity hoarding behaviour, rather than reduce it, by inadvertently incentivising prospecting for grid access. Further, we consider that secondary capacity trading for larger users will be limited in terms of number of concluded transactions/MWs (i.e. will not be a fluid market). It is not clear how secondary capacity trading will help to de-risk investment for constrained projects as an agreement will be needed at the point of investment and endure for the lifetime of the project to be financeable at the outset. This will introduce a long-term dependency upon another network user, which will also likely increase investment risk/cost.

Question 6: Do you agree that a comprehensive review of forward-looking DUoS charging methodologies, as outlined in paragraphs 4.3-4.7, should be undertaken? Please provide reasons for your response and, where possible, evidence to support your position.

We do not agree that a comprehensive review of forward-looking DUoS charging should be undertaken, however we consider that all DNO charging methodologies should be aligned, for example having a single methodology for EDCM. We do not agree with Ofgem's proposals.

In considering the effectiveness of locational charging at the distribution level, we note that the review conducted in 2015 by the Distribution Charging Methodology Forum (DCMF)

Methodology Issues Group[2] found that the introduction of the EDCM locational use of system charging:

- Did not have a significant impact on connecting user's decisions.
- Users decisions were influenced much more significantly by connection charges, rather than use of system charges – *"Ofgem have reported that 95% of connections over the last 3 years have not triggered any network reinforcement…"*.
- That network reinforcements accounted for a small proportion of the overall cost recovery through EDCM – in 2015/16 less than 10% of EDCM allowed revenue related to reinforcement charges.
- That going forward, the EDCM should not include a reinforcement cost signal.

Therefore, we consider the introduction of more extensive locational charging to be poorly justified as it would introduce unnecessary complexity, loss of transparency, excessive volatility and concerns about the validity of the methodologies and the underlying data.

Reasonable change in grid charging rules is a feature of the electricity market that is understood and accepted by investors. However, excessive volatility in grid charges and erosion of confidence in current and future tariffs was exemplified when the Kintyre-Hunterston subsea link was included in the final tariffs for 2016/17. This one single reinforcement increased the locational element of the wider zonal generation TNUoS charge for zone 7 by approximately £6-7/kW – an increase of 50%. Further, the forecasts provided by National Grid were inaccurate. The forecast 2016/17 tariffs provided in July 2015 (9 months ahead of the start of the charging year) indicated an overall charge for intermittent generation of £12/kW, whilst the outturn final tariff for the zone was £18/kW. The charge was underestimated by National Grid by 30% - in a zone which was already facing extremely high locational TNUoS charges.

There are alternative means, which have been shown to be effective in reducing demand on network assets that would otherwise require reinforcement and these are more suitable to manage power flows in real time within a smart network environment. The use of Demand Side Response (DSR) arrangements and new approaches developed under the Smart Network and Low Carbon Network initiatives are reported in Annex C. In so far as these schemes reflect the need to reduce demand then it should be possible to derive incentives or rewards to generators.

Locational forward-looking charging signals for renewable generators are only influential before a project reaches financial close. Once a project has located itself and committed to build then subsequent locational charge variations represent nothing more than cost-risk to be hedged. They cannot be responded to. Moving a wind farm is unfeasible, for example. It is also unrealistic to expect a renewable generator to manage its operational output in response to year-on-year changes in grid charges, as such behaviour would not pass a cost-benefit analysis. The only feasible response is to pay or to cancel.

Cost of investment - we are concerned that, even with good justification through economic theory, the real-world impact of implementing the proposals will be to further erode investor confidence, increase investment risk/cost for new generation capacity in the UK and reduce competition. As set out above, this likely increase in investment risk could be translated into higher prices for consumers through several avenues:

- Reduced/slower delivery of subsidy-free generation to market.

[2] ENA, December 2015, "Extra-High-Voltage Distribution Charging Methodology Review Group Report" http://www.energynetworks.org/assets/files/electricity/regulation/DCMF/EDCMReviewGroupFinalReport%2031Dec2015.pdf

- Increased transmission constraint costs due to delay in delivery of subsidy-free projects as the suite of projects available for bid-off actions will remain dominated by pre-existing projects.
- Reduced competition within wholesale markets.
- Increased strike prices within future Contracts for Difference rounds.
- Increased capacity market prices through delayed deployment of subsidy-free low-carbon generation to market.
- Reduced deployment of further DSR/flexibility due to network charging uncertainty.

Impact on future of balancing services – there is a significant interface with the future design of transmission and distribution balancing services markets. These are not yet well-defined or understood throughout industry and the potential for unintended consequences of introducing new charging arrangements may cut over the operational needs of the network and potentially increase the costs of network operation.

We are supportive of capacity-based charging rather than time of use (ToU) charges such as under a Triad regime, which is inefficient.

There would need to be a strong cost-benefit case for making CDCM more granular – as new metering equipment, IT systems and data flows would be needed. Unless it can be demonstrated that such changes would deliver good value for money for the consumer and effect desirable changes in generator behaviour (without unduly penalising them) then this option should not be progressed.

If such a review is to proceed, then we advise that predictability and stability must be the key focus of any resulting charging methodology, at least in their implementation on renewable generators, to facilitate the least-cost electricity production. It is therefore imperative that Ofgem commission independent and extremely thorough whole-energy-system cost-benefit analysis before making any decisions on the outcomes of this SCR.

Question 7: Do you agree that the distribution connection charging boundary should be reviewed, but not the transmission connection boundary? Please provide reasons for your response and, where possible, evidence to support your position.

We are concerned about moving the charging boundary for distributed generation to a shallow approach. We consider that this will increase the investment cost for generators due to higher risk factors used by investors to accommodate variations in Generation DUoS compared to connection charges, largely driven by:

- Uncertainty regarding the charging methodology and the potential for charging regime to change under open governance regime.
- Ongoing charges which are linked to factors outside of the project's control (e.g. connections/disconnections of other network users).
- Difficulty in forecasting charges.

Shallow charging boundary at distribution will increases the overall network charging risk – moving the cost from upfront capital cost to long term operational cost exposed to methodology changes.

Investments in generator capacity are long term, over 25 years, and once an investment decision has been taken, there is limited ability to then respond any further to changing locational network signals. Therefore, to effectively influence the behaviour of generators and other network users connected at HV and EHV, charging signals need to be able to be reasonably predictable over the full project lifetime. Variability and uncertainty in network charging arrangements represents a significant challenge for investors. To achieve enough confidence ahead of investment in network charge forecasts, investors need to be confident in the stability of the network charging regime.

Although the specifics of charging methodologies can be reasonably expected to evolve, there must be confidence that the regulatory policy approach and code governance processes will remain stable. Significant step changes in charging policy cannot be reasonably factored into an investment case, far less a series of significant shifts, which is currently the case.

We are further concerned that more locational DUoS charges will become more unpredictable and volatile, particularly for renewable energy projects that tend to be located on more remote parts of the networks. This has been seen at transmission, with projects that are connected to more remote parts of the system seeing extreme changes in tariff year-on-year due to the locational methodology. We note that some generation TNUoS tariffs have changed by the order of 30% or more year-on year, and some EDCM import capacity tariffs have changed year-on-year by a factor of 10 or more.

This volatility and the difficulty in getting confidence in current and future tariffs was exemplified when the Kintyre-Hunterston subsea link was included in the final tariffs for 2016/17. This one single reinforcement increased the locational element of the wider zonal generation TNUoS charge for zone 7 by approximately £6-7/kW – an increase of 50%. Further, the forecasts provided by National Grid were inaccurate. The forecast 2016/17 tariffs provided in July 2015 (9 months ahead of the start of the charging year) indicated an overall charge for intermittent generation of £12/kW, whilst the outturn final tariff for the zone was £18/kW. The charge was underestimated by National Grid by 30% - in a zone which was already facing extremely high locational TNUoS charges.

Further, moving to a shallow charging boundary will mean that distribution connected users are exposed to the future activity of other network users. Currently, distribution network capacity restrictions are included in network reinforcement capital cost contributions. This is paid for by connecting parties. However, under a shallow charging boundary there is a risk that distribution connected users will be exposed to locational price increases due to future connections from other users – which is currently the case at transmission. However, the impact of one large distribution-connected user on local flows is often far larger than the equivalent impact on flows on the transmission system, with the potential to impose far greater volatility on future locational charges than even the current transmission charging methodology has shown.

We reiterate that predictability and stability must be the key focus of any charging methodology, at least in their implementation on renewable generators, to facilitate the least-cost electricity production.

Question 8: Do you agree that the basis of forward-looking TNUoS charging should be reviewed in targeted areas? If you have views on whether we should review the following specific areas please also provide these:

a) **Do you agree that forward-looking TNUoS charges for small distributed generation (DG) should be reviewed, as outlined in paragraphs 4.19-4.23?**
b) **Do you consider that forward-looking TNUoS charges for demand should be reviewed, as outlined in paragraphs 4.24-4.27? Please provide reasons for your response and, where possible, evidence to support your position.**

a) We do not agree. We are concerned that introducing locational generation (or negative demand locational) TNUoS to embedded generation will decrease the competitiveness of these projects, making it harder for smaller market participants to enter the market. This will reduce overall competition in the market place. Only a small proportion of all generation capacity currently connected or contracted at transmission is backed by independent owners/operators, with the remainder controlled by the 'big 6'. Whilst at distribution, independent owner/operators have a much larger market share.

Further, introducing locational signals which can unexpectedly increase after project investment decisions have been made would disadvantage independent developers as they would be more exposed to risk of change. Larger players, with wider asset portfolios (spread over technologies and locations), have a better opportunity to hedge the risk and minimise the overall impact on their business. This change would make it more difficult for independent project developers to continue to operate in the market, reducing competition overall. We ask that Ofgem set out a rational justification of their proposals to expose only distribution generation to both TNUoS and DUoS charging as part of the impact assessment analysis before making any final decisions.

b) No comment

Question 9: Do you agree that a broader review of forward-looking TNUoS charges, or the socialisation of Connect and Manage costs through BSUoS at this time, should not be prioritised for review? Please provide reasons for your response and, where possible, evidence to support your position.

Yes, we agree.

Paragraph 2.31[3]: Connect & Manage is paid for by all who pay BSUoS (and ultimately by all consumers), not just the connecting party who has benefited. We disagree with Ofgem's inference that only the connecting party benefits from Connect & Manage. It has been a successful policy which has allowed generators of clean power to connect to the system sooner than would otherwise have been the case. This benefits all consumers.

Many of the components of BSUoS costs are for national transmission network operations and not related to geography at all. Constraints are also driven by a whole range of factors, many of which are not in the control of the connecting party. In our view this is not a priority area of work.

Question 10: Do you agree that there would be value in further work in assessing options to make BSUoS more cost-reflective, and if so, that an ESO-led industry taskforce would be the best way to take this forward?

We do not agree that this review is required for the following reasons:

- BSUoS is not currently intended to be cost-reflective, as it is effectively equivalent to a 'residual' charge – and recovers costs incurred for balancing the system ex-post. TNUoS charging already contains a locational forward-looking element reflecting network constraints.
- At present, there is very poor communication and wider industry understanding of the drivers behind balancing system actions, which risks a revised methodology being driven by a select few with a narrow remit. Furthermore, the introduction of cost reflective charges would penalise existing network users that can do little to respond to another new charging signal.

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[3]Ofgem, July 2018, "Getting more out of our electricity networks by reforming access and forward-looking charging arrangements"
https://www.ofgem.gov.uk/system/files/docs/2018/07/network_access_consultation_july_2018_-_final.pdf

- Such a review would again likely increase the risk as well as the cost of investment. The increase in investment risk will be translated into higher prices for consumers through several ways as already highlighted in our response. We believe that this could potentially lead to slower delivery of subsidy-free generation to market, increased transmission constraint costs and reduce competition within wholesale markets. The higher risk premium could also translate in increased strike prices for future Contracts for Difference rounds as well as capacity market prices. We believe there is also a risk of reduced deployment of DSR and flexibility as a result of network charging uncertainty.

Question 11: What are your views on whether Ofgem or the industry should lead the review of different areas? Please specify which of SCR scope options A-C you favour, or describe your alternative proposal if applicable. Please give reasons for your view.

We consider that the scope of the review should be limited to the ‘narrow approach’. We believe that attempting to review forward-looking charging arrangements alongside evolving the choice of network access rights for larger users (moderate approach) and the allocation of rights (comprehensive approach) is likely to overwhelm the industry and limit the ability of participants to engage and respond to the issues. However, we do consider that the need to review the ‘firmness’ of network access rights needs to be addressed as a matter of priority and should be included in the baseline scope (‘narrow approach’) going forward.

Any changes to allocation and re-allocation of network access can be managed effectively through existing code governance arrangements.

Question 12: Do you agree with our proposal to launch an ‘Option 1’ SCR for areas of review that we lead on? Please give reasons for your view.

Yes, we agree. Nonetheless, change introduced through an Option 1 SCR with industry delivering the relevant modifications requires Ofgem to set out specific, detailed direction, and also maintain effective engagement throughout the process to prevent inefficiencies in delivery. Ofgem must ensure that representation by all types of interested parties is enabled when debating proposals for a change, including businesses which would be most affected by changes to access and charging, as we have seen through the CFF process. We would like to stress that the code modification process can exclude the views of smaller parties and generators, which can lack the resource to take part in change proposal discussions.

Question 13: Do you agree with the introduction of a licence condition on the basis described in paragraphs 5.11 and 5.12 and Appendix 5? Why or why not? Do you have any comments on the key elements set out in table 7 of Appendix 5a, or consider there are any other key elements which should be included? Please give reasons for your view.

No comment

Question 14: Do you have any comments on the draft wording of the outline licence condition included at Appendix 5b? Please give reasons for your view.

No comment

Question 15: What are your views on our indicative timelines? Do you foresee any potential challenges to, or implications of, the proposed timelines and how could these be mitigated?

For processing time, we reiterate the need for whole-system cost-benefit analysis, including the impact on emissions and the UK’s ability to meet decarbonisation targets. From previous significant charging changes we are concerned the timescales for development may be too tight - it would not be unrealistic to expect an additional 6-12 months of development being needed to undertake appropriate analysis and educate the market.

Many of the proposals are fundamental in nature and will have a significant impact on business plans across the whole industry. For the transition arrangements it is essential that any implementation is performed with a commensurately large notice period and/or phasing arrangement.

Question 16: What are your views on our proposals for coordinating and engaging stakeholders in this work?

We have attended Charging Futures Forum and webinars and consider these to be an effective way of engagement to complement formal consultations. We have members who sat on each of the Task Forces, and we would welcome similar representation on any future working groups that may be required as this work progresses.