To: Interested Stakeholders

Direct Dial: 020 901 7000
Email: FutureChargingandAccess@ofgem.gov.uk
Date: 15 July 2020

Dear Stakeholder,

Request for information in relation to Electricity Network Access and Forward-Looking Charging Review: impacts of reform options implementation

On behalf of the Gas and Electricity Markets Authority ("the Authority"), Ofgem ("we, us") is writing to stakeholders to seek information in connection with the Electricity Network Access and Forward Looking Charges Significant Code Review ("the SCR"). We have published a template spreadsheet on our website for the provision of responses.

We do not expect all market participants to answer all questions in the template spreadsheet, as some are only applicable to a specific group of industry parties. Setting the "respondent type" drop down in the "guidance" worksheet will update the response type column on the "questions" worksheet, which will indicate whether a response is required.

Alongside using our information gathering powers to gather information from large suppliers and network companies, we are requesting information from other interested parties on a voluntary basis. We would strongly encourage you to provide us with responses to specific questions, as detailed in this open letter, and any further information that you consider would inform our consideration of the impacts of implementing the options we are currently taking forward for the SCR.

Background to the SCR

We launched the SCR in December 2018 as an important part of our programme of reforms to the energy system. Through this programme, we want to enable competition and innovation, decarbonisation at lowest cost and to protect consumers in the transition to a smarter, more flexible, and low carbon energy system. In the launch statement, we identified a series of issues with the current arrangements and set out three principles to guide our assessment of options to resolve those issues[1].

In March this year we published an open letter to set out the shortlist of policy options we intended to take forward for detailed assessment[2]. As we explained in that letter, we believe some of the initial options did not merit being taken forward based on assessment against our guiding principles. The open letter was preceded by two working papers published in 2019 which include further detail[3].

We are placing a high emphasis on principles-led assessment in our decision-making and continue to undertake further in depth qualitative assessment of the shortlisted options. To support our principle-based assessments, we have commissioned CEPA and TNEI to undertake modelling to assess the potential quantitative impacts of shortlisted options.

We will consult on our draft Impact Assessment (IA) and Minded-to-Decision in the autumn with a final decision and IA expected in early 2021.

This Request for Information

To inform our draft IA we are now seeking – through this request for information (RfI) – information about the costs to the industry of implementing our shortlisted options in four key policy areas described in Annex 1, with the full list of questions presented in the associated response template. We are specifically seeking input in relation to:

- Upfront costs of changes to IT systems, including billing systems
- Upfront costs of changes to internal processes
- Any impacts on ongoing costs of operating IT systems and internal processes (both any additional costs and any cost savings)

---

[1] https://www.ofgem.gov.uk/system/files/docs/2018/12/scr_launch_statement.pdf
[2] https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options
[3] https://www.ofgem.gov.uk/publications-and-updates/access-and-forward-looking-charges-significant-code-review-winter-2019-working-paper and https://www.ofgem.gov.uk/publications-and-updates/access-and-forward-looking-charges-significant-code-review-summer-2019-working-paper

We are not considering costs associated with credit cover or financing in respect of options which influence cashflows between participants – those costs will be captured elsewhere in our IA.

Where possible, please provide costs which specifically relate to 2023 implementation of options under the SCR **over and above** those for other reform areas. We note that there is a strong interaction with the implementation of market wide half-hourly settlement through the Electricity Settlement Reform SCR. We are particularly interested to hear from parties on the impact on implementation costs and timescales of the interactions between system changes required for that SCR and the Network Access and Forward Looking Charges SCR.

Quantitative responses should be provided wherever possible, supported with a description of how the costs have been derived, any assumptions made, and the associated uncertainty.

Prior to publishing this RfI, we have incorporated feedback from the SCR Challenge Group and Delivery Group. We will build on that engagement with a stakeholder workshop during the period for which the RfI is open, at which we will present the RfI and invite clarification questions from stakeholders. We will also be maintaining a frequently asked questions publication to assist stakeholders in preparing responses. Alongside this RfI to industry, we will be engaging bilaterally with Elexon and Electralink to understand the impact on their respective systems.

The information we receive may be used for any purposes relating to our functions including carrying out an Impact Assessment as per Section 5A of the Utilities Act 2000.

Confidentiality and disclosure

Any information provided to us which relates to the affairs of an individual or a particular business will be subject to statutory restrictions on disclosure under Section 105 of the Utilities Act 2000. However, there are exceptions to the statutory restrictions, including where the disclosure is necessary to facilitate our statutory functions (such as publishing information to promote the interests of consumers) or those of other public bodies.

We cannot provide any assurances in relation to the treatment of information which may be the subject of a request made under the Freedom of Information Act 2000 (FOIA). However, we will always consider whether the statutory restrictions on disclosure apply to the requested information and therefore whether one or more of the FOIA exemptions apply.

We intend to publish material from the responses to this request in an anonymised and/or aggregated format. Before deciding whether to publish any information relating to the affairs of a particular licence holder or business, we are required to consider whether it is appropriate to redact any information on the basis that the information would or might, in our opinion, seriously and prejudicially harm the interests of that person ("confidential information"). In order to enable us to conduct this assessment, we would ask that you indicate in your response whether you consider any information to be confidential information and provide brief reasoning in support of your views. A space on the spreadsheet has been added in order for you to include comments on confidentiality in relation to each question. Where appropriate, we may seek further representations from licence holders or businesses at a later stage in respect of any specific information we are proposing to publish for any other purposes.

Your response

Please use the template spreadsheet to provide your response. Email your response to FutureChargingandAccess@ofgem.gov.uk by 14 August 2020.

Where a licence holder is part of a corporate group with multiple electricity supply licences, we request that one consolidated reply is provided to us on behalf of all the relevant licence holders which received the information request.

For electricity supply licence holders – if any "white label" electricity suppliers operate through your electricity supply licence, please include in your response any costs that they expect to incur. If this is commercially confidential, please arrange for any associated white label electricity supplier(s) to provide this data directly to us.

If you have any questions about this Notice, please contact FutureChargingandAccess@ofgem.gov.uk

Yours sincerely,

Andrew Self
Deputy Director, Electricity Access and Charging
Signed on behalf of the Authority and authorised for that purpose

Annex 1: Detail on each policy area

The questions in this RfI are grouped by policy area, covering:

- Distribution Use of System (DUoS) charges
- Transmission Network Use of System (TNUoS) charges
- The connection charging boundary for distribution users
- Definition and choice of access rights for larger users

In relation to each policy area, we are predominantly seeking to quantify the costs of a subset of our shortlisted options in relation to which we expect to undertake detailed modelling but are also seeking some input in respect of other shortlisted options.

For the avoidance of doubt, this does not mean we are ruling out other shortlisted options at this stage but are simply seeking to ensure that the information provided in response to this RfI can be closely related to our quantitative IA modelling.

Please assume implementation in April 2023 for all options. We are also seeking to understand the extent to which implementation costs may vary for other implementation timescales (see "over-arching questions" section).

Some questions make a distinction between "small" and "large" users. We use "small" to refer to households and non-domestic users that do not have an agreement for their maximum capacity usage.

In addition to responses to the specific questions raised, we welcome respondents' input on costs associated with other shortlisted options.

DUoS charges

In relation to DUoS charges, we are seeking input on three key areas:

- The impact on costs associated with the DNO charge setting process
- Costs linked to the extent of locational granularity of charges
- Implications of different options for charge design

Charge setting – questions 1.01 to 1.03

We are seeking input on the cost of the DNO tariff-setting processes relative to the status quo (including code modifications which have been approved for implementation but not yet implemented) for:

- Retaining load flow modelling at EHV with representative network model(s) used for lower voltage assets
- Moving to an asset-based model using existing data (e.g. the Long Term Development Statement)

We appreciate that it is difficult to provide quantitative approximations without further detail on the precise methodology to be deployed. As a result, we would initially welcome any quantitative information DNOs can provide on the costs of implementing the **current methodologies**, particularly with respect to load flow modelling for the EDCM, alongside any further information you are able to provide on the costs associated with the options above.

Locational granularity – questions 1.04 to 1.09

We are seeking input on the cost differential between two options for locational granularity of DUoS charges:

- Charges which vary by primary substation
- Charges which vary by bulk supply point

We expect that the main implication for industry of this decision will be driven by the number of "sets" of tariffs generated – where a "set" may include similar tariffs as current arrangements (i.e. domestic, small non-domestic, unmetered supplies, LV site specific, LV sub site specific, HV site specific, LV generation, LV sub generation and HV generation).

Under the primary substation option, there would be ~5,800 sets of tariffs GB-wide, compared to ~800 sets of tariffs GB-wide for the bulk supply point option. This compares to the status quo of 14 sets of tariffs GB-wide at HV and LV and approximately 2,500 site-specific EHV tariffs.

We are currently seeking to quantify the costs of implementing those approaches on your systems and processes. In particular, we are interested in the limitations of using the current method of assigning customers to tariffs using Line Loss Factor Classes (LLFCs), whereby each tariff has an associated LLFC and each customer is assigned an LLFC enabling the applicable tariff to be determined. We recognise that this approach is likely to have limited scalability and are seeking input on the maximum number of tariffs which could be accommodated using the LLFC approach.

An alternative approach would likely rely on new registration data items. We will be engaging bilaterally with Elexon and Electralink on how a new approach could function, and are seeking input on implementation costs for two distinct options for different levels of granularity:

- Using LLFCs for assigning tariffs to customers
- Using new registration data items such as location ID and customer type to assign tariffs to customers

We expect that the implementation and operating costs of different options for locational granularity will be heavily influenced by the approach to time of use charging. In particular, we are seeking to understand whether there would be a fundamental difference between:

- The existing approach of a consistent set of red/amber/green timebands across each DNO region
- Bespoke red/amber/green timebands for each primary or BSP, with the red timeband targeted at peaks on the local network
    - For example, one location could have red 1600-1900 every day, amber 0800-1600 every day and green at other times; while another location has red 1000-1400 every day, amber 1400-2000 every day and green at other times.
- Shorter timebands which are fixed GB-wide
    - For example, six four-hour time periods could apply in every location every day (e.g. band 1 0000-0400, band 2 0400-0800 etc.), with time of use signals derived from the differential between rates in each four-hour period. Different locations would have higher rates in different four-hour timebands, but the timebands themselves would remain fixed.

We are also considering introducing time of use signals which vary by season. For options with red/amber/green timebands, this would likely involve both the timebands and rates changing on a seasonal basis, while for the option with fixed shorted timebands only the rates would change between seasons with the timebands remaining fixed. We are seeking input on any costs associated with seasonal variation.

We would also welcome input on whether there would be implementation costs associated with aligning timebands for unmetered supplies to those for metered customers.

Charge design – questions 1.10 and 1.11

With regard to charge design, we are currently working on the basis that each demand customer group will face a combination of the tariff elements included in their existing DUoS charges (e.g. fixed and unit charges for smaller customers; fixed, unit, agreed capacity and reactive power charges for larger customers), albeit with different weighting compared to the status quo. As a result, we do not expect significant implementation costs or changes to ongoing costs due to charge design for demand. Charge design for generation may see more widespread use of capacity charges (which are currently only used at EHV).

TNUoS charges

In relation to TNUoS charges, we are seeking input on two key areas:

- TNUoS for distributed generation
- TNUoS charges for demand

Distributed generation – questions 2.01, 2.02, 2.04, 2.06 and 2.08

We are seeking to quantify the costs associated with aligning the structure of TNUoS charges for distributed generation with that for transmission connected generation which is currently charged based on agreed capacity (formally Transmission Entry Capacity or TEC). For the purposes of this section of this RfI, distribution generation should be construed as that with a Maximum Export Capacity, as agreed with the DNO, greater than 1MW.

We are currently exploring three options for the way in which this approach could be delivered:

- Maintaining the status quo for distributed generation whereby the ESO charges suppliers and suppliers charge generators (note – under current arrangements the "charges" in question are negative, i.e. generators are credited)
- Require the ESO to levy TNUoS charges directly on distributed generation
- Require the ESO to levy TNUoS charges for distributed generation on distributors connected to the transmission network (i.e. DNOs, and potentially IDNOs in the future), with distributors passing that charge on to distributed generation
    - In this instance, we are also seeking to understand the impact on implementation and ongoing costs of whether the capacity on which charges for distributed generation are based is the subject of a separate agreement between distributed generation and the ESO; or uses the Maximum Export Capacity as agreed with the distributor.

Demand – questions 2.03, 2.05 and 2.07

We are seeking cost input on two options:

- Charging all demand users based on usage 4-7pm, potentially with seasonal variation

- Charging smaller demand users based on usage 4-7pm and a modified Triad approach for larger users, both with the potential for seasonal variation

Distribution connection charging boundary
Many of the options we are considering for changing the connection charging boundary are relatively straightforward changes to the apportionment rules in the common connection charging methodology. While these may have material impacts on connectee behaviour, those impacts are being explored in our impact assessment, and we expect these options will have low implementation costs.

There are, however, two options for which we are seeking to quantify implementation costs:

- Making connectees liable for the costs of network reinforcement should they disconnect from the network, and requiring associated securities
- Changing payment terms for connection charges, enabling connectees to pay over a longer period of time

Securities – questions 3.01 and 3.03
New arrangements may require new connectees to take on liability for the cost of network reinforcement undertaken to enable their connection should they subsequently disconnect from the network.

For example, if a fully "shallow" connection charging boundary were used, connectees would fund only extension assets through their connection charge. But they could retain ongoing liability for the reinforcement assets for which they would have been charged under the existing "shallowish" boundary for a period of time after connection. In this instance, new connectees would be required to provide securities for that liability, typically in the form of either a cash deposit or parent company guarantee. We are seeking to quantify the costs of systems and administration to manage such securities.

In order to quantify these costs, please assume all new connectees are liable for the cost of reinforcement assets which would be chargeable under a "shallowish" boundary for a period of 10 years after connection. This is not intended as an indication on the likely outcome, but simply to ensure a degree of consistency across respondents. We are also seeking input on whether the costs are likely to be proportional to the value of connections to which they apply to enable us to quantify the costs associated with such arrangements to a subset of customers.

Transmission connectees are already exposed to liabilities in respect of transmission works both pre- and post-connection. As a result, we are asking the ESO to provide the ongoing costs of administering the securities associated with those liabilities to further support cost estimates from distributors.

Changes to payment terms – question 3.02

We are seeking to quantify the costs of systems and administration for DNOs of enabling connectees to pay connection charges over a longer period of time. Note – we are not seeking to quantify any costs to DNOs of financing any payment deferral, but only the cost of administration.

Please assume all connectees take deferred payment terms over a 15-year period when estimating the cost. This is not intended as an indication on the likely outcome, but simply to ensure a degree of consistency across respondents. We are also seeking input on whether the costs are likely to be proportional to the value of connections to which they apply to enable us to quantify the costs associated with such arrangements to a subset of customers.

Access options

Questions 4.01 to 4.08

We expect many of the options we are considering for access rights to have relatively low implementation costs. Existing access right options would also continue to be available for users to choose from. We are, however, keen to understand the implications of:

- More defined, non-firm access rights – this would provide choices about the extent to which users' access to the network could be restricted (e.g. the percentage of time that users are willing to be curtailed). Users would be protected from the risk of DNOs exceeding the level of curtailment agreed.
- Time profiled access rights – this would provide choices other than continuous, year round access (e.g. off-peak access).
- Shared access rights – this would allow users across multiple sites, in the same local area, to obtain access up to a jointly agreed level.

These access rights could either be:

- Agreed between the distributor and customer, and valued through the connection charge or use of system charges, depending on our decision on the connection charging boundary

- Agreed between the supplier and customer, and valued through use of system charges

If valued through the connection charge, then alternative access choices could reduce the upfront cost of connection. The bespoke nature of connection charges also allows for development of bespoke access right design. If valued through use of system charges, then alternative access choices could reduce ongoing distribution network charges. However, there is limited ability to reflect bespoke access rights via use of system charges, instead users would be allocated to the most appropriate standardised access option.

For non-firm access rights, we are seeking to understand costs which will be incurred over and above those already in place, for example costs which arise from increasing the scale of Active Network Management (ANM) and improving the definition of access rights (e.g. users agreeing limits on the extent to which they are curtailed).

In particular, we would encourage network owners, system operators and suppliers to consider any additional costs associated with monitoring and ensuring compliance with alternative access choices. Please include all costs, regardless of whether those costs are likely to be customer funded.

We are also seeking to understand the sensitivity of implementation costs depending on whether access rights are the subject of a distributor to customer agreement, or distributor to supplier agreement.

Overarching questions

Timescales – questions 5.01 and 5.02

In relation to all responses provided which relates to system and process changes, we are seeking to understand the timescales associated with those changes, and whether the costs included throughout your response would differ materially under longer implementation timescales.

Interaction between options – question 5.03

We are also seeking to establish whether some combinations of options across the different policy areas (DUoS, TNUoS, access rights, connection charging) would drive materially different implementation costs if combined with one another.

Further comments – question 5.04

Finally, we welcome any further comments on implementation costs.