Energy Systems Catapult: Consultation Response

Ofgem Consultation – Access and Forward-Looking Charges Significant Code Review: Consultation on Minded to Positions[1]

25th August 2021

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Energy Systems Catapult (ESC) was set up to accelerate the transformation of the UK's energy system and ensure UK businesses and consumers capture the opportunities of clean growth. The Catapult is an independent, not-for-profit centre of excellence that bridges the gap between industry, government, academia and research. We take a whole systems view of the energy sector, helping us to identify and address innovation priorities and market barriers, in order to decarbonise the energy system at the lowest cost.

ESC welcomes Ofgem's consultation on their minded to position for electricity networks access and forward-looking charging review. In addition to responding to the specific issues that Ofgem are consulting on, we would like to offer some broader strategic observations.

Broader strategic observations regarding SCR network access and forward-looking charges

- **We welcome Ofgem's Full Chain Flexibility programme and wider review of TNUoS charges** and therefore accept the postponement of the decision on forward-looking DUoS in this context; this review, however, is belated and delay lengthens the uncertainty that users face. We therefore urge that completion and implementation of the Full Chain Flexibility programme and wider review of TNUoS charges be treated as **a high priority.**

  In relation to the forward-looking TNUoS and DUoS charges:
    - We believe that Locational Marginal Pricing (LMP) and Local Flexibility/Energy Markets have a role to play in driving much greater efficiency in the power system. We would therefore expect these initiatives to include **full consideration of the LMP and local markets alternatives**. At present, LMP will likely only be practical at a higher voltage level (e.g. 132kV and above – though this could change with improved network monitoring/data/control at lower voltages and with growth in distributed energy resources that would ensure sufficient liquidity behind nodes) and below this the choice should be a combination of DUoS charges and options implemented through Local Flexibility/Energy Markets where DNOs/DSOs would potentially undertake local balancing and aggregation to facilitate interaction with national markets. We hope that Ofgem's further consideration of DUoS charges, to be published later in the year, will also include consideration of Local Flexibility/Energy Market options implemented in combination with LMP applied to the transmission level.
    - For the upcoming minded-to decision on DUoS, **consideration must also be given to fairness and equity issues** in a broad sense, though particular attention should be paid to consumers' rights to access the full value of their flexibility (via self-control/automation or third party control/automation). For example, it will be important to create an incentive for owners of electric vehicles to adopt smart

[1] https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

charging (to limit the network capacity required and reduce the need for new generation) but this should not lead to higher charges for those not able to afford or not yet transitioned to zero/low carbon technologies.,

- **On connection charges,** we welcome shallow charges for demand given the need to accelerate the electrification of demand to achieve Net Zero goals, but **urge all generation be exposed to charges incorporating wider locational signals beyond local reinforcement costs to influence its siting**.
- In principle**, generation of different sizes and located at different voltages need to be treated equitably,** not just in relation to network charges but also with respect to targeted policy outcomes (e.g. carbon, air quality, reliability, resilience), technology support policies (e.g. CfD eligibility) and market design rules (e.g. fully incorporate marginal costs, internalise externalities, remove price distortions and market barriers). A key objective should be to ensure that system costs are accurately reflected in price signals, with all generators exposed to those signals. Inconsistent application of such principles results in an unlevel playing field between different energy resources.
- **On access rights**, we welcome the clearer definitions for distribution level resources and the requirement for DNOs to procure flexibility above thresholds agreed with users – but **work must continue as the market develops to progress development of options for the future**, moving in the direction of more equal treatment of transmission/distribution assets and resources. In the end, it is crucial that **flexibility be fairly compensated**, including at distribution level and in ANM zones.
- **Discontinuities in the regulatory regime can distort** investment decisions as they can incentivise developers/investors to size plant based on cut-off points. It will be important to fully consider the potential for distortion associated with any proposed discontinuities in regulatory treatment as otherwise corrective action will be needed later, which is highly disruptive for innovators, developers and investors.
- The focus of all new proposals – relevant to this whole consultation, not just this question - must be on achieving more optimal outcomes, requiring close attention to the detail of design and implementation. **Charges should be designed to be cost-reflective and free of distortions in order that efficient and optimal outcomes result** in relation to investment and network use. Close attention must be paid to the incentives or disincentives that DNOs and ESO are subject to, and their coordination, with the objective of achieving optimal outcomes from a whole systems perspective. Key to driving efficient development of the network and investment decisions will be effective incentives for DNOs and ESO through the RIIO price control regime, effective implementation of whole system planning processes (e.g. Local Area Energy Planning (LAEP)) and reforms for better coordinating ESO(FSO) and DNOs(DSOs).

Response to Ofgem's Questions

3. Connection boundary

Question 3a: Do you agree with our proposals to remove the contribution to reinforcement for demand connections and reduce it for generation? Do you think there are any arguments for going further for generation under the current DUoS arrangements? Please explain why.

Demand

We support the removal of the contribution to reinforcement for demand connections on the basis that demand often has little discretion on where to locate, or the volume of access required. For example, the decarbonisation of heat and transport, especially in remote communities, will be more problematic and delayed if individual heat pumps and street charging facilities are subject to reinforcement charges.

Generation

Conversely, generation generally has greater freedom about both where to connect and the size of plant to be installed. We would therefore argue that the generators' greater freedom of where to locate (and hence the greater opportunities they have for responding to connection charges) is a valid reason to retain the proposed contribution to reinforcement. We have concerns that the proposal to reduce generators' contribution to reinforcement could distort generation investment decisions. If a generator is only liable for reinforcement costs at their connection voltage, there will be an incentive to connect at the lowest possible voltage level. This could create a distortion and lead to smaller generators being built than would be economically efficient.

We are aware of locations where the network needs significant reinforcement to accommodate new generation, and that this can create a barrier to development because of the high costs for the first party applying to connect. While removing the contribution to network reinforcement at the voltage level above the connection would help, we believe this would be a blunt instrument in that it would socialise the costs regardless of whether there was a realistic prospect of other parties choosing to connect, and hence could increase the cost of decarbonisation to the end customer. We believe that a better approach would be to identify areas where there is sufficient certainty of multiple connections to justify strategic investment combined with a mechanism to recover the costs from connecting parties. One possibility would be to link this to the Local Area Energy Planning process.

We would also argue that locational value - with charges varying by geography to encourage siting of generation near places of high and growing demand and where network reinforcement is or will be needed, guided by holistic system planning - should be reflected in upfront connection fees, especially if charges are to be collected through fees rather than DUoS for non-firm connections (as per Question 4d).

In principle**, generation of different sizes and located at different voltages need to be treated equitably,** not just in relation to network charges but also with respect to targeted policy outcomes (e.g. carbon, air quality, reliability, resilience), technology support policies (e.g. CfD eligibility) and market design rules (e.g. fully incorporate marginal costs, internalise externalities, remove price distortions and market barriers). A key objective should be to ensure that system costs are accurately reflected in price signals, with all generators exposed to those signals. Inconsistent application of such principles results in an unlevel playing field between different energy resources.

Question 3b: What evidence do you have on the effectiveness of the current connection charging arrangements in being able to send a signal to users and what do you think will be the effect of our proposed changes? How does this vary between demand and generation connections?

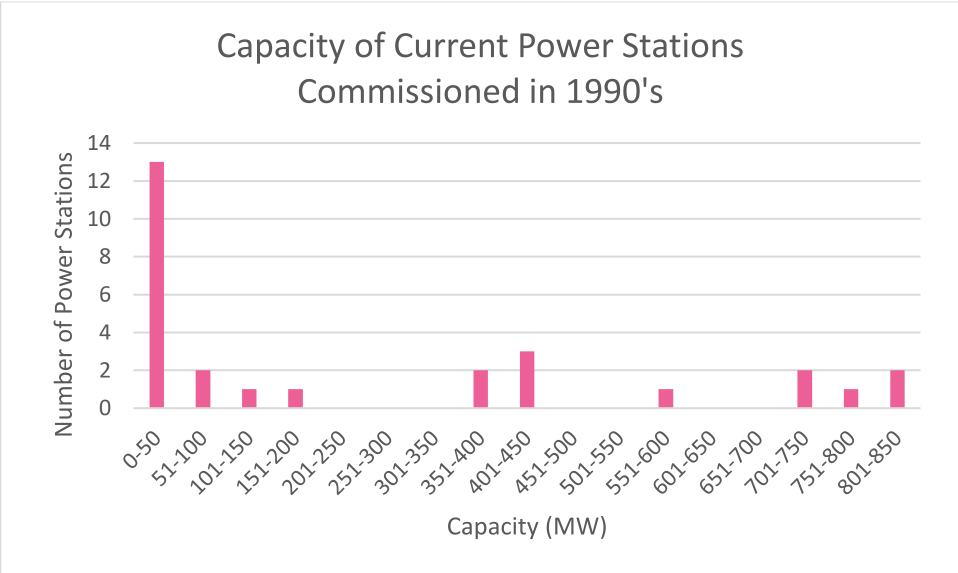
Demand

On the demand side the electrification of heat and transport will create demand that is unable to respond to locational signals. This implies that the question should be about how to most efficiently upgrade the network, rather than exposing the customers to the costs involved. The current arrangements would also lead to equity issues such as:

- Some customers getting a cheaper connection because there is spare capacity within the network, compared to others who have to pay for reinforcements either because they apply later or happen to be supplied by a heavily loaded part of the network.
- Those who are able to charge their EV at home, where the reinforcement costs are likely to be socialised, versus those using commercial charging points.

Generation

Historically, generation has responded to the existing charging regime. This has both encouraged investment in suitable parts of the network and led to market distortions, as is demonstrated by the large number of generators choosing to size their plant just below the 50MW/100MW break points for regulatory treatment (see Figure below). It seems likely that the proposed rules could have a similar effect with generators sizing their plant so that it can be connected at the lowest possible voltage level.



Question 3c: What are your views on the effectiveness of the current arrangements in facilitating the efficient development and investment in distribution networks? How might this change under our proposals where network companies are required to fund more of this work?

The current arrangements socialise the costs of domestic demand increases, while recovering significant sums from new connections. While this approach is reasonable when existing demands are relatively static, they are harder to justify if, as expected, the demand from existing customers is growing due to the electrification of heat and transport. There is risk that existing customers have the reinforcement costs associated with their load growth socialised, while new parties connecting are expected to pay in full.

Key to driving efficient development of the network and investment decisions will be effective incentives for DNOs through the RIIO price control regime and effective implementation of whole system planning processes (e.g. Local Area Energy Planning (LAEP)).

Question 3d: Do you agree whether the need to provide connection customers with certainty of price reduces the potential for capacity to be provided through other means such as flexibility procurement? How might this change under our proposals?

The current rules make the provision of capacity via flexibility procurement a financial risk to the customer. While this effect will be lessened by moving to a shallower connection boundary which moves costs from the customer to the DNO and other customers, it will not be removed. However, other approaches are possible; for example, where a customer pays the cost of a traditional connection, the DNO could be allowed to provide this via flexibility with a one-way sharing mechanism such that a proportion of any savings would be refunded to the customer, but with no downside risk. This would remove the risk to the customer from the use of novel ways for providing capacity.

Question 3e: What are your views on whether we should retain the High Cost Cap? Is there a case for reviewing its interaction with the voltage rule if customers no longer contribute to reinforcement at the voltage level above the point of connection?

It is entirely reasonable to protect customers as a whole from funding excessive reinforcement works associated with generation connecting to the system. We support applying the High Cost Cap to the voltage level above the connection level. Otherwise, in those cases where there will be large costs at, for example, 11kV, there will be an incentive for generators to pick a size of connection that can just be accommodated at 400V, leaving other customers to pick up the large costs. This would distort decision making by generators and disadvantage other customers.

Question 3f: What are your views on the recovery of the costs associated with transmission that are triggered by a distribution connection? Does this need to be considered alongside wider charging reforms or could a change be made independently?

Close attention must be paid here to the incentives or disincentives that DNOs and ESO are subject to, and their coordination, with the objective of achieving optimal outcomes from a whole systems perspective.

The location of the boundary between transmission and distribution is arbitrary, as illustrated by the fact that in Scotland 132kV is considered as transmission, while in England and Wales it is classed as distribution. Hence, to use different charging principles on the two systems runs both the risk of treating parties in an inequitable manner and distorting their business decisions. It is important that this issue is resolved as it can be expected to become more prominent with electrification of heat and transport. For example, if general domestic demand growth (the costs of which are socialised) drives the need for additional supergrid transformer capacity, how is the DNO to recover the costs involved if they cannot be recovered through DUoS? The DNO needs to be incentivised to minimise the costs of the combined investment in **both** transmission and distribution networks.

Question 3g: What are your views on the likelihood of inefficient investment under our proposals (e.g., an increase in project cancellations after some investment has been made)? Are there good arguments for further considering introducing liabilities and securities to mitigate this risk?

Given the anticipated growth in both demand and embedded generation, there is a high chance that any investment stranded by the cancellation of the associated connection project could be re-purposed. On this basis, it is probably unnecessary to introduce further liabilities for connecting parties. In any case, the DNOs will have a natural incentive to manage this issue by delaying expenditure so as to minimise the period of risk.

Question 3h: What are your views on whether the interactions between our connection reforms and the ECCRs must be resolved before we are able to implement our proposed reforms? How do you factor in the effects of the ECCRs (if at all) into decision making, given the levels of uncertainty around subsequent connectee(s)? What suggestions do you have to make our policy and the ECCRs work together most efficiently?

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4. Access rights

Question 4a: Do you agree with our proposal to introduce better defined non-firm access choices at distribution? Do you have comments on their proposed design?

We agree that customers agreeing to non-firm access should have much greater certainty about the level of curtailment without compensation that they could be subjected to. A key principle to uphold is that flexibility must be fairly compensated, free of discrimination in relation to size or type of energy resource.

However, users may not know in advance what type of access they need, and needs may change over time. Therefore:

- sufficient data and transparency are required from the networks so that users can make choices with confidence; and
- some flexibility should be built into the new arrangements so that users can change their access arrangements over time.

Question 4b: Do you agree with our proposal to introduce new time-profiled access choices at distribution? Do you have any comments on their proposed design?

Its introduction, and therefore its design and implementation, must improve utilisation of the network. For example, timely adjustments must be possible as network conditions change with time.

Time of use charges are already a familiar concept to network users so this will probably be the easiest type of access reform for them to engage with. We think these (and non-firm access rights) should be open to existing users as well as new connectees in order to maximise the number of parties who can benefit, and thus provide system benefits.

Ofgem should ensure that DNOs hold sufficiently frequent reviews to engage with users on the time periods for limited access, informed by monitoring of sufficient quality regarding where and when constraints occur.

Question 4c: Can you identify any benefits to shared access rights, which would indicate we have underestimated the likely take-up?
We recognise that the definition of access rights and the opportunity to trade them can enable greater flexibility and more efficient use of the network, especially as conditions change in future with growth in DER.

Shared access can potentially enable the freeing-up of capacity on a longer-term basis and more cheaply than flexibility services procurement. Implementation of shared access rights must be well thought through. For example, shared access rights across significant parts of a DNO network if not designed or implemented well could potentially limit the DSO's ability to manage a constraint that affects a subset of the parties sharing the access rights. In other words, a constraint could be worsened if the parties sharing access rights chose to reallocate them amongst themselves.

Existing local energy projects/demonstrators, such as the Greater Manchester Combined Authority (GMCA) Local Energy Market, under UKRI's Prospering From the Energy Revolution (PFER) programme, could present opportunities to test the appetite for shared access and the ways it can be effectively designed and implemented.

The focus of all new proposals – relevant to this whole consultation, not just this question - must be on achieving more optimal outcomes, requiring close attention to the detail of design and implementation.

Question 4d: Do you have any comment on our proposed choice about how to reflect access rights in charges (i.e. connection and/or distribution use of system charges)?
We think the current proposal is sub-optimal for generation. Charges should be designed to be cost-reflective and free of distortions in order that efficient outcomes in relation to investment and network use result. As detailed in our response to question 3a, how charges are recovered from generators matters and locational value should therefore be accurately reflected in charges.

Upfront charges will more strongly influence siting decisions relative to DUoS but only if there is locational differentiation in prices.

Question 4e: Do you agree with our proposal to not prioritise the introduction of new transmission access choices as part of this Significant Code Review?
While we do not see a need to prioritise new transmission access choices, we would reiterate our view that the transmission/distribution access and charging arrangements should be equitable and hence not distort a market participant's decision as to which network they wish to connect to.

Question 4f: Do you have views on how access rights should be standardised across DNOs?

Access rights should be equitable to connected parties. Hence, any difference in approach between the DNOs should be well justified. Differences in DNOs' underlying physical network arrangements, however, are likely to be a factor for consideration.

Question 4g: Do you have any views on our proposed timescale of 1 April 2023 implementation?
As the new regime will be more attractive to connectees than the existing regime, there is a risk of customers delaying their connection in order to take advantage of the new arrangements. As many

of these connections will be associated with low carbon technologies, both in terms of generation and demand, there is a risk that there will be a delay in the adoption of low carbon technologies. This is an important factor to consider for the implementation process/timing and to avoid unintended consequences.

5. TNUoS charges for SDG

Question 5a: Do you have any evidence that SDG does not contribute to flows in the same way as large generation and, therefore, should not be charged on a consistent basis?
A power system study will demonstrate that the only difference to transmission flows between 1MW of generation on the transmission system and 1MW on the distribution system is the associated change in losses.

In addition to reducing energy losses in networks, SDG may, however, contribute more effectively to other system benefits compared to larger scale generation. So it is important that Government's targeted outcomes are clearly defined by policy, that system costs are accurately reflected in prices and that resources/technologies of different type and size are treated equally.

Question 5b: Do you agree with our threshold for applying TNUoS generation charges of 1MW? If not, what would be a better threshold and why?
There is a history of generators being sized in response to discontinuities in charging and licencing arrangements. Ofgem need to be confident that such a rule will not distort investment decisions and lower overall system efficiency as a result. For example, is it possible that in future a 5MW solar farm will be partitioned into 5 x 1MW sections that can then avoid paying TNUoS?

Question 5c: Do you have any evidence that distribution connected generation at a grid supply point has a different impact than directly connected generation?
See answer to 5a above.

Question 5d: Do you have a preference for one of our options for addressing the local charging distortion? If so, please indicate which option and provide your reasons. Are there any options we have missed?
We prefer the second option of levying a local charge on each embedded generator in respect of its impact on assets between the GSP to which it connects and the MITS. This is on the basis that it would distort the siting of generation if there was an area on the mainland that was required to pay a contribution to the remote island links. (It is worth noting that if the charging zones were altered such that each remote island was a charging zone, then the two options would effectively become identical.)

Question 5e: Do you support our position that we should consider transitional arrangements? If so, do you have a preferred option and evidence to support the benefits or risks associated with each option?

While it seems reasonable to allow sufficient time for existing parties to reflect the proposed changes in their commercial arrangements, allowing more time would delay the delivery of the expected benefits.

Question 5f: Have we identified all the options for administering TNUoS generation charges for SDG? If not, what options have we missed, and why would they be preferable to those we have identified? Can you provide any evidence regarding the implications of the different administrative options for your business?

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Question 5g: Are there any specific issues you think we need to consider, as part of our work on the future role of network charges? Why are these important to consider?

We believe that Locational Marginal Pricing (LMP) and Local Energy/Flexibility Markets have a role to play in driving much greater efficiency in the power system. We welcome Ofgem's Full Chain Flexibility programme and wider review of TNUoS charges. We expect these initiatives to include full consideration of the LMP and local markets alternatives. LMP will likely only be practical down to a certain voltage level (e.g. 132kV) and below this the choice should be a combination of DUoS charges and options implemented through Local Energy/Flexibility Markets – the local equivalent of the national Balancing Mechanism. We hope that Ofgem's further consideration of DUoS charges, to be published later in the year, will also include consideration of local market options implemented in combination with LMP applied to the transmission level.

7. General questions

Question 7: Do you have any other information relevant to the subject matter of this consultation that we should consider in developing our proposals?

As stated in question 5g, we would encourage Ofgem to consider the potential merits of Locational Marginal Pricing and Local Energy/Flexibility Markets.