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25th August 2021

National Grid ESO response to the Access and Forward-looking Charges Significant Code Review: Consultation on Minded to Positions

Dear Patrick,

This response is on behalf of National Grid Electricity System Operator (NGESO) and is not confidential. National Grid ESO is the Electricity System Operator for Great Britain. We balance electricity around the country second by second to ensure that the right amount of electricity is where it's needed, when it's needed – always keeping supply and demand in balance. As Great Britain transitions towards a low-carbon future, our mission is to enable the sustainable transformation of the energy system and ensure the delivery of reliable, affordable energy for all consumers. We use our unique perspective and independent position to facilitate market-based solutions which deliver value for consumers.

We support the minded to decision, in particular the additional information provided about distributed generation (DG) paying Transmission Network Use of System (TNUoS) charges. We believe that DG do use the transmission system today, and therefore are supportive of the minded to decision that they should then also face transmission charges. We do however believe that it is important, that if DG face transmission charges, that they should also have the same opportunity to access revenue streams as generators connected to the transmission network. The 1MW threshold is therefore important, as it will allow DG who wish to participate in the balancing mechanism (BM) to do so.

There are a few key considerations which we believe are important to highlight:

- **A review of TNUoS**

  We are supportive that the minded to consultation notes a review of TNUoS. This is an area which we look forward to working with industry and Ofgem on. We believe that for a review to deliver the most benefit to consumers, TNUoS charges should not be considered in isolation and therefore wider consideration is required for the interactions with markets, network constraint costs and Balancing Use of System (BSUoS) charges. This review creates uncertainty in the near term and we believe it appropriate to align the timing of DG paying TNUoS with the introduction of the new TNUoS methodology. This will provide DG with more certainty around the charges they will face and be able to plan for this within their businesses.

  We also note that the demand locational reforms are not part of this minded to decision, and believe that encompassing this into a wider review of TNUoS would give a holistic TNUoS solution.

- **ESO contractual relationship with DG**

  We believe that the contractual relationship with DG can both provide DG with easier access to ESO markets whilst minimising the obligations on DG compared to transmission connected generators.

  There are also wider benefits to the ESO – and ultimately to consumers – in contracting with DG. Having greater visibility of DG data will support several key areas including demand forecasting, scheduling, the dispatch and settlement of ESO services and system planning processes. This data will also support the production of industry publications such as Future Energy Scenarios (FES), the Electricity Ten Year Statement (ETYS) and the Network Options Assessment (NOA). In addition, although not obligating parties to participate in ESO markets, we believe we would see an increase in participation which would increase flexibility to balance the system and competition in the market. It is also important to note that it would be essential that any agreements would need to work alongside any Distribution System Operator (DSO) services and approaches.

Contracting with DG 1MW and above would be a significant undertaking for the ESO, potentially resulting in the number of contracts being actively managed increasing from c500 to c5000. This would require increased resource dependant on the complexity of the contractual frameworks, increased volumes of new customer onboarding and servicing requirements, and the degree to which a new system might be able to create and manage all contracts digitally. However, we believe that the benefits of contracting with DG outweigh this.

Due to the benefits associated with this, and significant time required to develop and implement a new approach to contract with DG, we propose that the contractual solution should commence in advance of DG paying TNUoS. This would reduce the complexity of charging DG TNUoS once the new TNUoS methodology was created, as the data set and mechanism would already be in place.

Our detailed response to your questions is appended to this letter.

We welcome the opportunity to further discuss the points raised in this response and look forward to working with both Ofgem and industry as the detail of these reforms are worked through. Should you require further information please contact James Stone in the first instance at James.Stone@nationalgrideso.com.

Yours sincerely

Mark Herring
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National Grid Electricity System Operator

Appendix

Proposals for distribution connection charging (Section 3)

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.

On balance, we agree with the proposals in respect of changes to the connection charging boundary. Removing or reducing upfront costs would reduce barriers to entry for both demand and generation connections. This we believe, should reduce cancellations and encourage more connections at distribution which will help facilitate the transition to Net Zero.

However, reductions to risk and the upfront costs for those connecting at distribution will have an opposite and equal effect on the funding to be recovered by Distribution Network Operators (DNOs) for their network as it will now be a function of connection activity. This will increase Distribution Use of System (DUoS) charges for consumers but may also result in greater challenges for DNOs when fixing tariffs in advance. This is because they will need to account for more connections activity and the risks associated with the DNO investing, but the project not reaching completion for whatever reason. Ultimately, this may create further uncertainty for industry parties such as Suppliers in terms of forecasting, which may in turn result in them including additional risk premia within their tariffs.

Whilst renewable generation and storage will be key to Net Zero, we believe going any further with generation connections reforms than those already proposed could transfer too much risk to consumers. This is because evidence has shown that ‘User Commitment’ has acted as a suitable barrier by allowing efficient projects to connect whilst reducing the number of inefficient connections.

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?

No comment.

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?

We are unable to provide specific commentary on the effect of current arrangements on connections at distribution. However, from our experience operating the arrangements for transmission works, we believe the introduction of a shallower connection boundary has been successful in terms of promoting more efficient outcomes. Therefore, we believe a shallower approach being adopted at distribution would also promote more efficient investment in distribution networks. Currently for transmission, generation and storage connections use the 'User Commitment' arrangement which is a 'shallower' approach whilst demand connections use the 'Final Sums' arrangement which is a 'deep' approach. Anecdotally, the conversion rate (applications that result in connections) seems to be higher for generation connections compared to demand connections, however this is skewed by a very low volume of demand connections.

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?

No comment.

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?

No comment.

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?

Currently, for users connecting at transmission any costs associated with sole-user transmission works are recovered over several years via a shallow connection charge. In some circumstances users connecting at transmission may incur no upfront costs to connect and only pay an application fee and the agreed securities. Whereas those connecting at distribution which trigger transmission works are charged these costs upfront as part of the DNO connection charge. This differing treatment in terms of cost recovery is a significant barrier in some parts of the country and will continue to grow as an issue until it is resolved.

We believe it is a pragmatic solution to review this issue as part of a wider review of TNUoS charging, however, we are mindful of how long this review could take, especially as consideration of 'aggregated access rights' to the transmission system would need to be considered. For example, if the DNO has 800MW of embedded generation at a Grid Supply Point (GSP), does this mean reinforcement work needs to take place to accommodate all 800MW? It is not clear from the minded to position if Ofgem's view is that all generators =>1MW should contract with NGESO for 'firm' transmission access or not, whether this access should be retroactively applied (i.e. should this proposal apply to all parties who are currently contracted on a 'non-firm' basis), or how parties are upgraded from 'non-firm' to 'firm' connections (if that is the intent).

This view of 'aggregated access rights' will directly affect the volume and therefore value of works needed (on the transmission system as a result of distribution projects) as will any sharing between DUoS- and TNUoS-liable parties. There will also be interactions with the Connect and Manage regime (which is used to determine if works must be completed before a party can connect – i.e. how firm the connection is) which will need to be considered as it could result in inconsistent treatment between Transmission and Distribution connected parties.

We believe this review would therefore need to find an appropriate mechanism to determine the 'correct' amount of reinforcement required (on the transmission system as a result of distribution connected projects) and an appropriate sharing mechanism. Especially as some reinforcement on the transmission system may be driven by demand connections on the distribution system who (based on our reading of the minded to decision) will not face these reinforcement costs.

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)? What are the arguments for and against further considering introducing liabilities and securities to mitigate this risk?

Whilst introducing liabilities and securities may create a barrier to entry, we do believe that without any form of securitisation there is a significant risk of stranded reinforcement on both the transmission and distribution systems. We consider that the mechanism by which any value of liabilities is determined will be key in order to strike the right balance between removing barriers and reducing consumers' exposure to inappropriate levels of risk. We believe lessons can be learned from the 'User Commitment' approach at transmission to ensure this balance is achieved and its current implementation to distributed generation via User Commitment and the associated CUSC modifications (CMP192 and CMP223). For example, ensuring sites are only liable for the proportion of the works they would use and a securitisation approach to this liability which reflects the likelihood of the works being stranded. This also needs to be considered against how any works are paid for and the timing of such payments i.e. customers could then choose the payment plan/securitisation approach which is best suited for their project.

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?

No comment.

Proposals for definition and choice of access rights (Section 4)

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 with the proposal to introduce better defined non-firm access choice at distribution. At present, transmission generators agree and pay for a level of Transmission Entry Capacity (TEC). This provides them with a level of firm access to the system which is clearly defined. We consider that better defining non-firm access choices at distribution would further align with those arrangements already in place for transmission. It would also provide certainty to users by allowing them to more easily agree a level of access that meets their needs which may encourage more connections. Having clearly defined access rights may also provide wider benefits in terms of network planning and more efficient use of the system.

We support the proposed design to define new non-firm access arrangements in relation to the percentage that users are willing to be curtailed. We consider this would be easily understood by users and clearly set out when and how much they may be curtailed. This would also protect them from the risk of DNOs exceeding the agreed level of curtailment and clearly set out what compensation a user would be liable for should those levels be exceeded. We are mindful however, that when a user is curtailed at distribution, they would also no longer have access at transmission. Therefore, we consider that any compensation mechanism relating to DNOs exceeding curtailment levels should not automatically make a distribution generator liable for compensation via the Connection and Use of System Code (CUSC). Rather any compensation should be payable by the DNO only.

In addition, any proposed design would need to consider a process for dealing with exceptional circumstances. For example, how would an emergency (driven by a need at transmission or distribution), whereby distribution connected users were required to operate outside of their agreed access terms be managed. There would also need to be clear processes for how the DNOs would manage and implement any new non-firm access choices to ensure that DNO operations were not negatively impacted.

Furthermore, we consider that additional work is required to confirm if the intent is that when agreeing non-firm access rights, the agreed capacity is to be the same as Transmission Entry Capacity (TEC), or a different form is to be used when defining users' access to the transmission system.

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?

We agree with the proposal to introduce new time-profiled access choices at distribution. As with the non-firm access choice proposals we consider the introduction of time-profiled access will provide certainty to users around when they can or cannot use the system. It will also allow them to more easily agree a level of access that meets their needs. This should encourage more efficient use of the system, allowing users to profile their access rights to move away from the network peak as well as better use of spare capacity on the network during off peak periods. This will potentially reduce and/or delay the need (and associated costs) for system development and reinforcement. We appreciate however, that this approach may not be suitable for all users.

We support the proposed design to define time-profiled access choices in relation to the percentage of a user's total access rights that are time profiled. We consider that this is consistent with the proposed approach for non-firm access choices at distribution and one which can be easily understood by users. It will also provide greater certainty in advance around when they will be able to import and export onto the network. However, we are mindful that new time-profiled access choices may create significant challenges for DNOs particularly in relation to changes to their systems to allow for greater network monitoring, as well as how any enforcement would be managed for non-compliance should users exceed their agreed access rights.

Furthermore, we consider that any time-profiled access reforms should only be introduced once a full assessment of the operational impacts at transmission has been undertaken, for example certain access rights choices may work well at distribution but could potentially have unintended consequences in terms of managing constraints at transmission and distribution boundary points.

Question 4c: Can you identify any benefits to shared access rights that we have not considered, which could impact likely take-up?

We have not identified any further benefits in relation to shared access rights than those already considered.

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 believe that reflecting non-firm access rights via connection charges would be appropriate given that there is a risk that DUoS charges inherently involve a degree of averaging in their calculation methodology which may potentially weaken any intended signals for users. However, any non-firm access rights charge design would need to consider how changes to a user's access over time would work in practice i.e. should a user wish to alter their level of non-firm access how would this be subsequently reflected via the connection charge.

Although it is still unclear around how access rights translate into charges in practice, we do support in principle, the proposal to reflect time-profiled access rights via use of system charges. The use of capacity charges that vary by time periods would be an appropriate methodology which would provide signals to users reflecting the effect their actions have on the system at specific periods. It should be noted however, that any time-profiled charge design would need to have adequate controls put in place to limit the opportunity for gaming in relation to price signals. For example, if charges for users were to be calculated using a user's prior year average usage, load factor or access value, then it could be possible for some users to intentionally change their behaviour within a charging year in order to affect future liabilities.

It is worth highlighting however, that treating non-firm and time-profiled access differently in charges (i.e. one via connection and the other via use of system charges) could provide an additional level of complexity for users when looking to understand the best approach for them to take.

Question 4e: Do you have any comment on our proposal to not prioritise the introduction of new transmission access choices as part of this Significant Code Review?

We support the proposal to not prioritise the introduction of new transmission access choices as part of this review. Current transmission arrangements ensure that through agreeing a level of Transmission Entry Capacity (TEC) and paying transmission charges, users are provided a level of firm access to the system. These arrangements already provide a level of certainty on the circumstances by which a user may be curtailed and limits on the extent to that curtailment. As such, users have clarity of when they will or will not be able to use the transmission system.

The introduction of new transmission access choices relating to time-profiled access should also not be prioritised. We do not consider there to be any apparent additional flexibility benefits of introducing time of use transmission access reforms. In addition, it should be noted that recent transmission stakeholder feedback via challenge groups suggests that time-profiled access is not a viable option, particularly for some renewables generators such as windfarms.

However, we are mindful that this should be kept under review as changes to stakeholder or system requirements may necessitate the need for new transmission access choices. We are therefore happy to work with industry to consider any improvements that could be made in terms of transmission access when there is evidence to demonstrate there is a need to do so.

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

We consider that codification would be an appropriate method to facilitate standardised access rights across DNOs. It is important that access rights are consistent across GB and that they provide transparency, a common understanding, and clarity for those affected parties. Implementing a single approach across DNOs would also be more efficient and would be beneficial for those generators who hold portfolios which span across several DNO regions. It would also allow for easier alignment with those arrangements at transmission.

Question 4g: Do you have any views on our proposed timescale of 1 April 2023 implementation?

We agree that the proposed access rights reforms to introduce better defined non-firm and new time-profiled access choices should be implemented for April 2023. This is because the new arrangements will provide clarity on choices for those connected at distribution. It will also allow for a more dynamic and flexible system and provide DNOs further flexibility in terms of connection offerings which will ultimately facilitate more connections. However, we are mindful that these access reforms should only be implemented once a full assessment of the operational impacts for DNOs and the wider network has been undertaken. This is because we consider that the introduction of such reforms may lead to sudden changes in user behaviours. This could potentially impact the local network's ability to cope which may subsequently impact the interface between the distribution and transmission networks. We are also of the opinion that the timing of access rights reforms should be co-ordinated and align with any DSO flexibility market design.

Proposals for TNUoS charging for Small Distributed Generation (Section 5)

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?

We are of the opinion that SDG do in fact contribute to flows in the same way as larger transmission generation. All generators use the transmission system in one form or another to a degree. Despite contracts being in place for distribution / transmission only or for both, current will flow across the GB system from the point of generation to demand centres in accordance with physical laws.

There are three potentially more tangible examples of DG using transmission:

- Stability – In the unlikely event where full system restoration is required, SDG will rely on the transmission system to re-power.
- Power Purchase Agreements (PPA) – SDG could sell their power to another user, this may be in a different location i.e. not possible without the transmission system.
- Exporting Grid Supply Points (GSPs) - Historically, capacities of SDG netted off demand imports at the same GSP. However, over recent years due to the increased volume of distribution connected

generation, there have been instances (as set out in the ESO cost drivers report and detailed as part of Ofgem's Embedded Benefits Review) where exported power can exceed local demand which means there is a negative draw on the system and GSPs can export onto the transmission system. This clearly highlights the usage of the transmission system and contribution to flows by SDG in the same way as larger generation and as such we consider SDG should be charged on a consistent basis with that of larger generation.

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?

We agree that the proposed 1MW threshold for applying TNUoS generation charges would be appropriate. This is because adopting this for charging purposes would align with existing thresholds currently used for planning purposes and participation in balancing services markets. It should be noted however, as with any threshold, there could be opportunities for gaming.

Our assumption is that the 1MW threshold is being introduced at an individual generator level, rather than at an aggregated level. It would be helpful for Ofgem to confirm this understanding.

In order to apply TNUoS generation charges there will be a requirement, dependent on the final decision in terms of administrative arrangements, to identify and agree a level of capacity or Transmission Entry Capacity (TEC) for generators (see response to question 5f for further detail). To do this and charge all generation above 1MW would be a significant amount of work, which would inevitably come at a cost, but as stated in our cover letter we consider the benefits in doing so outweigh this. However, we consider that to go further and include any SDG below the proposed 1MW threshold would be neither practical nor proportionate when considered against any potential benefits.

In addition, the DNOs via the DNO System Wide Resource Register (SWRR) already provide visibility of all generation above 1MW connected to the distribution network. This data could potentially be adopted for use within the existing transport model to set tariffs as well as invoice the relevant parties without the need for a new data set to be created from scratch. However, we believe that at present this data set may require some additional information (for example Grid Supply Point data) and further improvements to ensure it is robust enough to be used for tariff setting and/or invoicing purposes. There will also need to be consideration in terms of potentially setting up new industry data flows to accommodate this change.

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

We have no evidence to suggest that from a network power flows' perspective, distribution connected generation at a Grid Supply Point (GSP) has a different impact to that of directly connected transmission generation. We consider that exports from the same location at the same time will have the same impact regardless of whether they are from a transmission or distribution connected party.

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 views on pros and cons. Are there any options we have missed?

We are of the opinion that the option to maintain current classification of wider/local assets, specifically the classification of Main Interconnected Transmission System (MITS) nodes within the Connection and Use of System Code (CUSC) would not be appropriate when considering remote island links. The current MITS node definition may lead to multiple "wider networks" being connected via a local asset (local to specific generators) only, which undermines the principle of TNUoS local charging arrangements.

We consider that in principle the remote island links are "widely shared local" assets. Therefore, the option to amend the CUSC to treat all remote island links as wider assets, meaning such assets connecting to the MITS node are then captured under wider charges, would be preferable. However, we are also aware that some of the current wider charging principles may not be suitable for remote island links and believe that these principles need to be reviewed. In order to avoid any change over change, and associated "change fatigue", we consider that addressing this local charging distortion as part of a wider review of the TNUoS methodology to be a prudent approach.

It should be noted however, that a wider review would be a significant piece of work and any outcome may not be known for some time. Given that there are remote island links which are already under construction, with others planning to move to construction phase in the foreseeable future (subject to meeting certain criteria), we would support the consideration of transitional arrangements for remote island projects.

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?

We consider that delaying implementation of TNUoS charges for SDG would be of most value in terms of any reform to TNUoS arrangements and believe that this should be considered further as part of a wider review of the future role of transmission charging. However, we consider that such a delay should not automatically mean a delay to SDG agreeing contractual arrangements for access rights. We believe that agreeing access in advance of the introduction of TNUoS charging would provide system wide benefits in terms of improved ESO visibility of distribution-connected assets and increased system flexibility. It would also enhance the data relating to SDG which could be used to create an accurate and robust charging base in advance of TNUoS charges being levied on SDGs. It may also, dependant on the design of the contractual arrangements, encourage a larger number of SDG to actively participate (either directly or via updates to virtual Lead Party (VLP) arrangements) in balancing markets which could potentially increase competition.

Our concern with no transitional arrangements is that implementing changes to charge SDG TNUoS would not provide them with enough time to reflect any cost movements in their commercial arrangements and may, in some circumstances, mean plants seek to close due to no longer being financially viable. In addition, dependent on the final decision, the ESO may be required to invoice all SDG directly. This would be a significant change from current arrangements and a later implementation date would allow sufficient time for any required changes to be implemented.

We are of the opinion that a grandfathering approach, whereby charging liabilities differ between subsets or groups of distribution connected generators could also be, by its very nature, considered discriminatory treatment, and therefore would not be appropriate.

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?

We believe that the arrangements for contracting with SDG and invoicing TNUoS generation charges should be considered separately.

<u>Contracting with SDG</u>

Although requiring large scale transformation of some of the ESO's core processes and IT systems (i.e. connections and balancing markets), which would inevitably come at a cost, our preference is for the ESO to enter into contractual arrangements directly with all SDG above 1MW. The benefits of which are further detailed within our cover letter, and reflect the role of visibility of data in enabling Net Zero

We believe that any contractual solution must give the ESO full visibility of SDG and ensure that associated data is accurate and reliable as this will be used as the basis for allocating capacity and levying TNUoS charges. As a minimum this should include connected capacity, associated GSP, load factor and technology type. We think that the regulatory and technical obligations should be reviewed to determine if they should be applicable to all SDG above 1MW, reducing requirements wherever possible. The contractual arrangement should also give SDG the option to participate in the Balancing Mechanism (BM) and other market services (either directly or via updates to Virtual Lead Party (VLP) arrangements). Any future arrangements will need to consider how this coordinates appropriately with already established third party market platforms and existing DSO flexibility platforms.

We consider that the principles we have outlined would provide ESO better visibility of SDG (with consequential system flexibility and operability benefits) and would also allow SDG the opportunity to offset any potential introduction of TNUoS costs by revenue stacking through participation in market services. Furthermore, it could also lead to better alignment within the industry by potentially removing the differences in terms of obligations between Central Volume Allocation (CVA) and Supplier Volume Alllocation (SVA) metering systems.

Our understanding is that the commercial contract is a mechanism to allow SDG formal access to the Transmission system and to agree capacity. The need to allocate capacity, for access and charging, to an increased number of parties, including those that are already connected to the distribution system, will impact on the whole connections process (ESO, TOs and generators), both for new and existing parties. Further work is needed to confirm if the intent is for agreed capacity to be the same as Transmission Entry Capacity (TEC), or a different form.

Under the arrangement where the ESO contracts directly with SDG 1MW and above, work would need to be undertaken to identify impacts to DNOs and ensure that there is alignment with DSO flexibility markets.

Given the scale of change, it may be an appropriate time to conduct a whole system connections review. Even if a whole system approach to connections is not adopted, significant work is required to determine the optimum solution for new contractual arrangements with SDG and associated impacts to industry participants.

Although Suppliers may have strong direct relationship with their customers, managing and agreeing capacity on behalf of SDG users would require significant changes to the Supplier role and processes from the status quo. Particularly in relation to commercial agreements and the need to potentially improve understanding of distribution network capabilities, all of which may raise challenges in terms of implementation. As such we consider this option to not be appropriate.

A DNO-led option would create additional levels of complexity and would necessitate additional steps in terms of TNUoS invoicing. This we consider to be neither practical nor proportionate and as such believe that this option is also not appropriate.

Invoicing TNUoS

The option for the ESO to charge SDG for TNUoS charges via the Supplier, would, we consider, be the most practical and proportionate approach as the ESO already invoice larger distributed generators TNUoS charges via Suppliers. Therefore, from a process perspective, this would be a smaller change to that of any other options detailed within the consultation, however it may still potentially require a shift from “GSP group” to “GSP site”, as the SDG TNUoS charges will be based on generation zones instead of demand zones. We consider that any option to invoice all SDG directly would require significant scaling up of current administrative activities for the ESO, including new customer onboarding and servicing, clarifying the TNUoS generation charging methodology with Suppliers, issuing of significantly larger volumes of invoices and revenue collection. The expectation is that further investment would be required to the Charging & Billing (CAB) system in order to manage such a significant increase to invoice volumes as well as data flows and the enduring maintenance of required data bases, which may all come at a cost for consumers.

It should also be noted that uncertainty around the timing of and approach to invoicing SDG will create uncertainty in relation to system investment for all parties.

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 consider that any work on the future role of network charges cannot be considered in isolation and therefore interactions with markets, network constraint costs and Balancing Services Use of System (BSUoS) charges should be included. The various benefits to the system and to society that different market design options would deliver will also need to be considered as part of this holistic review. We are investigating this strategic problem as part of our Net Zero Market Reform project.

Additional considerations for a holistic review of network charges could include:

- the alignment in TNUoS and DUoS principles, given that a decision regarding DUoS charging reform is yet to be made
- a review of demand locational signals, to ensure network charging will deliver the right level of locational signals for us to achieve Net Zero in the most efficient way

General Question (Section 7)

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

No comment.