Access SCR Minded To Consultation

Solar Energy UK Response

About us

Since 1978, Solar Energy UK has worked to promote the benefits of solar energy and to make its adoption easy and profitable for domestic and commercial users. A not-for-profit association, we are funded entirely by our membership, which includes installers, manufacturers, distributors, large scale developers, investors, and law firms.

Our mission is to empower the UK solar transformation. We are catalysing our members to pave the way for 40GW of solar energy capacity by 2030. We represent solar heat, solar power and energy storage, with a proven track record of securing breakthroughs for all three.

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Would you like this response to remain confidential? No

Introduction

We welcome the opportunity to respond to this consultation. The outcome of the Access SCR will have significant implications for distributed generation, and as such we have provided recommendations and evidence below as to how the proposed minded to decisions will impact distributed solar generators across the UK.

Executive Summary

1. **Moving to a fully shallow Distribution Connection Charging Boundary for generation and demand:** We welcome and support the proposal to remove the contribution to reinforcement for demand connections and to reduce the contribution to reinforcement from generation. However, we would urge Ofgem to go further and also remove the contribution to reinforcement for generation sites. The industry can and should be supporting some of the costs of network expansion, but these costs must be fair and certain for developers. Based on evidence provided by Solar Energy UK members, we estimate that on average 100-300MW of additional potential solar capacity is being lost each year due to the current connection charging regime. Our recommended solution would be moving to a fully shallow connection charging boundary for generation to meaningfully

address the barrier presented by upfront costs to distribution connected generators. This would enable faster decarbonisation of the network and create parity between the transmission and distribution charging arrangements, thereby reducing distortions created by differing charging regimes. Charging demand and generation sites on the same basis would also simplify and expedite the process for connecting co-located sites, which we are starting to see much more of.

2. **Providing clarity and certainty of Access Rights and addressing the interplay with Active Network Management schemes:** Our members would welcome additional clarity on non-firm access choices at distribution. This would ideally allow some projects to connect more quickly and reduce the impact of curtailment. Consistency across DNOs and IDNOs with regards to the available non-firm access options is also critical to expedite and simplify the connections process for customers. In better defining access choices, network operators should also focus on providing connecting customers greater certainty of potential curtailment. Better visibility on possible future constraints and how this interacts with Active Network Management regions is essential to facilitate uptake of non-firm access rights. For example, our members have highlighted the need for visibility of half-hourly data on constraints on grid supply points. We would underscore the substantial challenges that the current Active Network Management (ANM) schemes present, particularly for solar projects, as the level of constraint can often be unknown until developers have progressed projects further into the development process, which then poses further risk on the economics of a project.

3. **The proposed TNUoS reforms are not fit for purpose and should be delayed to allow for a more comprehensive review:** Our members have expressed serious concerns about the proposed reforms to TNUoS for distributed generation. It is our view that the current TNUoS regime is not fit for purpose, and we would not support the proposed changes to charging TNUoS to SDG. As it stands the proposals would disincentivise generation projects in the north of England and Scotland particularly, which runs directly counter to the Government's intentions of levelling up. Our members have also raised concerns about calculating TNUoS on a MW Transmission Entry Capacity (TEC) basis. As TNUoS generation charges would apply to a generator's TEC and not on a volumetric basis this will disproportionately penalise certain types of generation, particularly solar. This is because solar has lower average load factors than other renewable technologies, hence a charge based on capacity is not reflective of the differing economics underlying the volume of generation from different technologies. We very much support a delay to the implementation of any changes until a wider review of TNUoS can be conducted. The current proposal will only exacerbate TNUoS costs for generators in the north of England and Scotland and would hugely constrain Scotland's growing solar industry.

Responses and Recommendations

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.

We welcome and support the proposal to remove the contribution to reinforcement for demand connections and to reduce the contribution to reinforcement from generation. However, we would urge Ofgem to go further and also remove the contribution to reinforcement for generation sites. The industry can and should be supporting some of the costs of network expansion, but these costs must be fair and certain for developers. It is also important that lower income households are supported in any future charging arrangement and not burdened with regressive network fees. The Government's own analysis shows utility scale solar to be the cheapest form of power generation.[1] Therefore, enabling accelerated roll out of PV will also have a knock-on effect on consumer prices and support decarbonisation at lowest cost.

The principal concern raised by our members is that unaffordable connection costs are holding back the deployment of distributed energy generation and delaying the decarbonisation of our energy system. The current connection charging boundary arrangement for distribution connected customers often results in upstream reinforcement costs that are prohibitive for developers and create a substantial barrier to the deployment of zero carbon generation, particularly solar PV.

Our recommended solution would be moving to a fully shallow connection charging boundary for generation to meaningfully address the barrier presented by upfront costs to distribution connected generators. This would enable faster decarbonisation of the network and create parity between the transmission and distribution charging arrangements, thereby reducing distortions created by differing charging regimes. Charging demand and generation sites on the same basis would also simplify and expedite the process for connecting co-located sites, which we are starting to see much more of. The proposed voltage role would likely drive more projects to 33kV and 11kV connections in the hopes of avoiding paying for 132kV connection charges. This will continue to drive haphazard and unbalanced investment in reinforcement.

From our engagement with network operators and the system operator to date, there is clearly a growing consensus that a shallow connection charging boundary for generation will help to enable more efficient and rapid development of the distribution network, which is urgently needed to enable the capacity of distributed zero-carbon generation needed to achieve the Government's net zero targets. Network operators

[1] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/911817/electricity-generation-cost-report-2020.pdf

should be allowed to move to a fully shallow connection charging boundary for generation to unlock the benefits of strategic network investment and expedited expansion of generation capacity.

We would argue that reinforcement requirements are fundamentally being miscalculated by network operators by not considering variable renewable generation as a factor in constraint modelling. Variable generation and flexibility are key to mitigating the immediate need for network reinforcement in some situations and this must be further taken into consideration when assessing reinforcement requirements. The proposed changes to access rights could also help address this in part. Capacity could be oversubscribed to some extent through enforcing time limitations on connection offers. For example, allowing solar to export during daylight hours, allowing wind to export during windier evening hours, and using storage to fill in the gaps via smart monitoring systems. This further underscores the argument for moving to a fully shallow charging boundary, as it would expose networks more directly to a distribution Balancing Mechanism market and incentivise the flexibility need to mitigate reinforcement costs.

We would also highlight that solar PV is already highly constrained in terms of where it can locate, which is a key reason cited for removing reinforcement costs from demand sites. A prospective large-scale PV generator typically proceeds by first identifying a potential site (e.g. a suitable rooftop or field with sufficient insolation value, and with relatively few planning restrictions - i.e. not an AONB or high-quality agricultural land) and then determines whether an affordable grid connection is available within a reasonable time frame. If no suitable connection options exist or there is too much uncertainty as to when a connection would be available, the project will be abandoned.

Reinforcement costs are causing projects to be abandoned

The Impact Assessment (IA) suggests that contribution to reinforcement is ‘unlikely to be the determining factor in whether a connection goes ahead’. This is undoubtedly not true when it comes to solar developments and seems to completely ignore the impact of the current system on these projects. As noted above, high connections costs are the principal barrier for new PV generation projects. Crucially, the IA does not consider the projects that never reach the point of submitting a connection offer, and we would argue is not seriously considering the impact on the future deployment of solar and its centrality to all scenarios in which net zero is delivered.[2]

Lack of clarity on costs at the start of the connections process further compounds the problem. Our members have reported several instances where sites have been abandoned due to reinforcement works being unexpectedly imposed. For example, we are aware of 3 different 50MW sites which were issued reinforcement costs of £15million, which equates to £300,000/MW. This is roughly six times the capex assumptions that developers build into their models for grid reinforcement and connections costs for the average 50MW project, and this presented an

[2] https://www.theccc.org.uk/wp-content/uploads/2020/12/The-Sixth-Carbon-Budget-The-UKs-path-to-Net-Zero.pdf

insurmountable financial barrier in each instance. These 3 instances alone resulted in 150MW of zero carbon generation being abandoned, despite the fact that the projects were otherwise entirely viable with land rights agreed and projects deemed suitable from a planning and further development perspective.

In other cases, the barrier presented by reinforcement costs is preventing projects from coming forwards in the first instance. Developers have reported that even where DNOs are indicating that unconstrained capacity is available, in many cases they have not been provided with unconstrained connection offers. This has led to many developers incurring additional costs to conduct in-house assessments to determine whether sufficient capacity is available before making a formal connection application, with the aim of identifying and avoiding any sites where any reinforcement is needed. If reinforcement is likely to be needed, developers will simply find a new location as the costs of reinforcement are assumed to be prohibitive.

Project-level decision making of this nature is commercially sensitive, so it is difficult to quantify how much potential capacity is not being built as result of this issue. Based on evidence provided by Solar Energy UK members, we estimate that on average 100-300MW of additional potential capacity is being lost each year. However, some Solar Energy UK members have indicated the actual amount could be much higher.

Reinforcement Costs and Capacity Constraints

Our members have noted that, in most circumstances, reinforcement costs are the principal barrier to development, but this of course goes hand in hand with the level of constraint on the network. This issue will only become more acute as heating and transport become electrified.

The Grendon Grid Group is a prime example of where network congestion and prohibitive reinforcement costs are stifling the deployment of renewable generation. Any generation applications that feed into nearly a dozen Grendon Bulk Supply Points (BSPs) trigger prohibitive upstream reinforcement costs due to several factors. The works required also present an additional barrier in many instances by potentially significantly delaying the Commercial Operation Date for projects.

Most new large-scale solar projects entering the development pipeline are between 20MWp and 49.9MWp total installed capacity, with the most common size for new planning applications being at 49.9MWp. Our members have reported that for several BSPs in the Grendon Grid Group a project of this size wishing to connect would incur contestable and non-contestable reinforcement costs regularly over £10million, in addition to having to wait 5 years or more from receipt of payment for the project to be energised.

Not only are the upfront costs prohibitive, but the timescale for connection is completely misaligned with solar development timelines. Even utility scale PV projects can begin supplying power within 6 months of beginning construction, with the entire process from site identification to completion often requiring less than 24 months.

This includes:
- Securing Land Consent – 6 months
- Securing Grid Contracts – 6 months
- Securing Planning Permission – 12-18 months

These processes run concurrently, meaning many projects can feasibly connect to the grid less than 2 years from beginning the process of engagement with the landowner. A delay of at minimum 5 years is untenable for both developers and investors, and significantly increases the risk of loss of capital investment.

Moving to a shallow connection charging boundary

If the decision is taken to move to a shallower or fully shallow connection charging boundary, we agree that it will be essential to ensure that Network Operators progress reinforcement works and anticipatory network upgrades where necessary, while minimising the risk of stranded assets. However, this should be done in a way that does not create additional barriers to development.

It is important that any upfront costs are applied in a proportionate and transparent way, as the current lack of clarity with regards to connection costs, and the upfront deposits that are already required by some DNOs, can also present barriers to projects. Our members have reported that in some instances developers are being asked to pay non-refundable deposits on top of application and connection costs that the developer would lose if the project were to not move forward for any number of reasons. In one recent example, a developer in SSE's southern coverage area was asked for a non-refundable deposit of £78,000, which presents a significant risk particularly to smaller developers. In this specific instance, the imposition of this non-refundable deposit could potentially lead to the project being abandoned, as well as a neighbouring battery project.

Charging arrangements are distorting connection decisions (transmission vs distribution)

While most solar projects are distribution connected, our members have reported that the differing charging regimes between transmission and distribution connected projects are impacting connection decisions. Some members are now looking at the transmission network as an alternative connection route and have commissioned investigations on distribution network and transmission charging to assess how this may impact responding to locational charging signals. However, here again our members report that ultimately the capital cost of the connection is the driving factor in decision making.

In certain areas of the distribution network where substantial headroom exists, often fault level reinforcement issues still arise, so a tertiary transmission connection option is an alternative connection route for lower capacity projects on the transmission system. However, third party works related to the distribution network can still be a concern for tertiary transmission connection options. In WPD's coverage area for example, members have reported that this can result in significant third-party reinforcement works being needed on the local distribution network due to power factor and voltage correction issues.

In some instances, the timescales and costs, both direct connection costs and wider area contribution costs, along with the undefined and variable nature of the wider area connection costs for future years, means that a National Grid transmission connection has often been found to be unviable or unable to be clearly modelled by developers to permit investment approval in the development cycle. Connection to the DNO transmission network can be more viable, subject to project scale. However, the variation in costs between DNOs, specifically around their substation configurations, can yield a variation in costs between £2.9m to £4m for a 40MVA connection, which again can significantly impact investment decisions and project viability.

Solar projects are typically impacted in scale due to the planning threshold of 50MW, above which projects are subject to the Nationally Significant Infrastructure Projects (NSIP) planning regime, and therefore the available transmission connections are not maximised. For example, if 55MVA is available on a line, as one member recently experienced, only 40MVA is contracted, leaving 15MVA available. However, connection costs of £3.9million meant the utilisation of this ‘15 MVA spare capacity’ was significantly outside the budget constraints of a viable project. The reinforcement costs to bring the 15MVA to 40MVA are way outside the budget scope of a project, even though there are wider benefits to the DNO in the reinforcement, yet the costs are not shared appropriately.

Connection charges and determining project locations

For many of our members, connection charges are the primary consideration when determining project locations. In Scotland especially, many developers have reported that this is the number one consideration. However, it remains the key consideration and potential barrier in almost all other cases in the rest of GB and NI. This includes issues like the distance between the Customer and DNO Substation. Other members have reported that connection charges are at least equivalent to the presence of statutory land designations, such as AONBs or National Parks, in identifying suitable locations, demonstrating the significant impact this has on identifying suitable project locations.

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?

As in our response to question 3a, the current arrangement is sending as strong signal to projects that would trigger reinforcement to avoid areas where networks are already highly congested. However, it is sending little to no signal to projects that would not trigger reinforcement, increasing the risk of free riding. Moving to a shallow connection charging boundary would significantly reduce the imbalance in the strength of this signal and allow for more projects to equitably come forwards in the areas that are best suited for solar generation.

The high reinforcement costs being sent by the current connection charging arrangements are essentially sending a strong locational signal to avoid the south of England, while at the same time the proposed TNUoS reforms would send exactly the opposite signal and drive projects south. These conflicting signals risk creating an imbalance in the recovery of costs and could exacerbate the risk of generation over-scaling demand in certain areas.

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?

As in our response to Question 3b, the signal that is being sent most strongly is for projects to avoid areas where the network is already highly congested, but only where they would directly trigger reinforcement. This is undoubtedly impacting the ability of network operators to optimally plan for reinforcement works in a way that is reflective of projected future demand. Instead, under the current regime these decisions are often delayed or avoided until new generation assets come forwards that trigger a clear needs case for reinforcement works.

It is difficult to understand the argument that there is a need to send a signal to generation to avoid unnecessary reinforcement in the context of the projected 200-300% increase in electricity demand in the coming decades. We would argue there is a clear need for areas with no remaining headroom to be prioritised for reinforcement to allow the network to keep pace with projected rise in demand. How investments are made in these areas should be driven strategically at a network operator level, and not by the first party that is willing to trigger reinforcement.

This would still be the case based on the shallower charging boundary proposed for generation. As in our response to Question 3a, we would note that solar generators are already highly locationally constrained, much as the IA acknowledges demand users are, and therefore face similar connection charging requirements.

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 certainty of price that would arise for new connections does not seem incompatible with greater use of flexibility and other means. However, any future reduction in connection charges could result in an increased number of applications, which might result in longer queues, and would need to be met with adequate additional resources to allow network operators to connect projects expediently.

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?

We would support the retention of the High Cost Cap. While the proposed changes to the connection charging boundary would likely reduce how often the cap comes into effect, it is still a useful mechanism to prevent very high levels of customer contribution where this may arise.

Question3f: 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?

Any changes along these lines should be considered alongside wider review of TNUoS charging reforms. If Ofgem introduces TNUoS charges for SDG, these users could also face higher costs compared to those on transmission. SDG would face the same ongoing network charges, but also an upfront connection charge in relation to transmission costs that a transmission connected generator would instead pay over several years. This could lead to a distortion between transmission and distribution connected generation.

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?

The introduction of additional securities and liabilities to mitigate the risk of inefficient investments is an understandable approach and is something that members have indicated they may support if done appropriately.

However, if any additional securities or liabilities were introduced, the agreed levels must be proportionate and reasonable. There is significant risk of undoing the benefit of the proposed reforms, in that the requirement to provide security might turn out to be as much of a barrier as the existing connection charging regime for distributed generation.

There are other approaches to mitigate this risk which might be preferable, for example the National Grid Wider Reinforcement Works cancellation charges regime. If a similar approach were introduced at the DNO level this would give network operators certainty of deployment without creating additional up-front barriers for developers. Any reinforcement works undertaken would be de-risked via the cancellation charge if projects fail late.

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?

The transition arrangements in moving to a shallow connection charging boundary are essential to ensure existing projects that have already paid for reinforcement are able to recuperate their costs. In this context, it is important to address the ECCRs to allow connection reforms to be brought in. ECCR charges effectively the same as triggering reinforcement so they can similarly be a barrier to development, and again underscore the need to move to a fully shallow charging boundary.

That said, we agree that in the case of subsequent connections, particularly for already connected projects, the initial DNO connectee should ideally still be able to receive reimbursement payments from by a later local connectee that they are entitled to under the ECCR, in relation to their own initial (shallower) connection payment, where some assets are now shared by the later local connectee.

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?

Yes, our members would welcome additional clarity on non-firm access choices at distribution. This would ideally allow some projects to connect more quickly and reduce the impact of curtailment. Consistency across DNOs and IDNOs with regards to the available non-firm access options is also critical to expedite and simplify the connections process for customers.

In better defining access choices, network operators should also focus on providing connecting customers greater certainty of potential curtailment. Better visibility on possible future constraints and how this interacts with Active Network Management regions is essential to facilitate uptake of non-firm access rights. For example, our members have highlighted the need for visibility of half-hourly data on constraints on grid supply points.

We would underscore the substantial challenges that the current Active Network Management (ANM) schemes present, particularly for solar projects, as the level of constraint can often be unknown until developers have progressed projects further into the development process, which then poses further risk on the economics of a project. Further, in the southwest of England, for example, out of the 26 Grid Supply Points (GSP), 18 either have ANM schemes, are out of capacity and have high reinforcement costs, or are not viable for connection.

Our members have expressed serious concerns that existing ANM indicators are flawed, in that they assume worst case demand versus maximum supply. This methodology for determining curtailment must be improved if it is to be the base for determining time-profiled or non-firm access rights.

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?

Yes, we agree with this proposal. Our members have expressed that a more flexible or time-profiled connection could be an attractive option for future development of utility-scale PV. For example, many solar projects could potentially tolerate substantial curtailment during non-daylight hours, provided that this arrangement was indeed coupled with sufficiently lower charges for the constrained access rights provided.

Priority access for solar during daylight hours is also important to consider for co-located sites, and how this would interplay with storage assets in particular. In any new time-profiled access options it is essential to understand how this is structured with other generating technologies.

Question 4c: Can you identify any benefits to shared access rights, which would indicate we have underestimated the likely take-up?

Shared access rights are clearly of benefit to mixed variable generation sites, or energy parks which often contain storage in addition to variable generation. Co-located wind and solar sites are a prime example of the benefits to shared access, as wind and solar are often complimentary in their generation profiles. Solar and wind operate in a particularly complementary manner: the periods of highest pressure (typically the least windy) tend to be the same times when solar outputs are at their highest.

This viability of this principle is already being embraced, for example in Scotland at Whitelee, where a forthcoming solar farm will use the same grid connection that the existing wind farm already uses. The predictability of solar makes it an attractive companion technology alongside other variable generations and energy storage.

Access rights reforms should provide clarity and introduce standard T&Cs on what shared access rights would be enshrined for each of the multiple users of the shared connection, specifically from a commercial perspective. This is essential to provide the clarity need by project developers to enter into such a shared arrangement.

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)?

No comment.

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?

No comment.

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

No comment.

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

It is important to balance expediency with the imperative to develop resilient solutions. While we support the proposed delay and wider review of the TNUoS element of this consultation, we would encourage Ofgem to implement the proposed reforms to connection charging and access rights as swiftly as possible to realise the benefits of accelerated project development now.

The timeline for implementation of these reforms should be accelerated wherever possible and ideally begin sooner than April 2023.

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?

Our members have expressed serious concerns about the proposed reforms to TNUoS for distributed generation. It is our view that the current TNUoS regime is not fit for purpose, and we would not support the proposed changes to charging TNUoS to SDG. As it stands the proposals would disincentivise generation projects in the north of England and Scotland particularly, which runs directly counter to the Government's intentions of levelling up.

Independent analysis conducted by SSEN demonstrates that the current charging methodology for TNUoS is not fit for purpose to meet either the Scottish or UK Government's net zero targets.[3] TNUoS was designed to encourage generators to locate close to the demand sites. While this may have been appropriate for a fossil fuel-based system, this is now creating disproportionate locational signals for a distributed renewables-based electricity system. Further, the variability of the TNUoS charging regime creates significant uncertainty and risk for developers, which will ultimately increase costs for consumers.

The changes proposed to TNUoS would inevitably drive developers south, whereas we have already highlighted, capacity is already highly constrained and there are few options for embedded generators apart from high-cost reinforcement. To go further, if any transmission connected generation is decommissioned this has no impact on the distribution network as the limiting factors are different. As such, there needs to be a better way to distribute the cost of decentralising the energy system and shifting generation to embedded DNO networks.

[3] https://www.ssen-transmission.co.uk/media/5261/ssen-transmission-tnuos-paper-february-2021.pdf

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 support the intention to continue capping SDG charges at zero, however we would note that removing the cap for generators below 1MW would disproportionately impact generators in Scotland and northern distribution zones, who currently pay no charge but would face charges for export during Triad periods under this proposal. The qualitative impact assessment from CEPA-TNA shows that while microgenerators today in the north of Scotland face embedded export charges equal to 0 £/kW, by 2024 and 2040 this charge will be roughly £36.5 and £80.6/kW respectively. This sends a perverse signal to generators for not generating at Triads periods.

Our members have also raised concerns about calculating TNUoS on a MW Transmission Entry Capacity (TEC) basis. As TNUoS generation charges would apply to a generator's TEC and not on a volumetric basis this will disproportionately penalise certain types of generation, particularly solar. This is due to the fact that solar has lower average load factors than other renewable technologies, hence a charge based on capacity is not reflective of the differing economics underlying the volume of generation from different technologies.

Members have also indicated the need for further clarity on whether and how the costs would be spread as more new generation comes online. Again, this should be done on a per MWh basis to more equitably distribute the impact. There are two elements in the calculation of TNUoS, the local charge which is based on TEC and the other is based on TRIAD TEC and capacity factors. If the TRIAD benefits are "derated" by capacity factor, why shouldn't the local charge also be assessed similarly?

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

Transmission connected distributed generation must go through 3 to 4 levels of voltage transformation before it reaches final demand at low voltage. Distribution connected distributed generation only must go through 1 to 3 voltage levels to reach final demand. As a result, the impact of a distribution connected distributed generation site on Transmission is less than its TEC. As such, if these sites are providing cheaper balancing at the LV to 132kV levels, should that not be recognised?

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?

No comment.

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?

As stated above, we do not believe that the TNUoS regime is fit for purpose, and therefore we very much support a delay to the implementation of any changes until a wider review of TNUoS can be conducted. The current proposal will only exacerbate TNUoS costs for generators in the north of England and Scotland and would hugely constrain Scotland's growing solar industry.

We would support grandfathering existing projects to help stabilise the volatility of network charges. If new TNUoS charges are introduced for SDG, this will intensify the current volatility of charges, which will lead to higher risk for investors and higher cost of capital. Therefore, we think that grandfathering projects is a valid option to stabilise network charges across the country.

We would like to highlight that the quantitative analysis from CEPA-TNEI that accompanies this consultation has serious limitations, specifically in relation to the locational allocation of capacity. The model assumes exogenous level of total capacity of each technology that is based in the FES scenarios from National Grid, which assumes renewable capacity installed year by year and does not consider the locational factor in the analysis. This means that the Ofgem model allows renewable capacity to choose where to locate on the system in response to expected revenues, which for distribution-connected producers are higher in southern areas and negative for some technologies in northern areas. This is extremely concerning because the model does not reflect the complexity of locational signals that currently exist.

The CEPA model shows that, over the period to 2040, technologies such as onshore wind, solar, biomass, and hydro in the north of Scotland would have losses (in terms of NPV) of up to £500/kW. For solar, the projected losses are over £318/kW, which would have a devastating impact on deployment in the region, undermining the fact that Scotland is otherwise well positioned to support significant expansion in solar deployment in terms of grid and land availability. Multiple independent analyses, conducted by National Grid, the Climate Change Committee, and the National Infrastructure Commission, have shown that the UK must deploy 40GW of solar by 2030 to keep on track with net zero by 2050, much of which is expected to be connected to distribution networks.[4] The model currently does not adequately address the role that solar in the north of England and Scotland will need to play in contributing to that target.

The quantitative analysis from CEPA-TNEI also indicates a potential benefit of £544m from charging SDG TNUoS. However, we think that this benefit could significantly change if the locational factor is considered. There are key determinants of the location of renewable capacity that are not captured in this model. Where these factors impact on locational decisions of investors, this would impact in turn on outcomes such as load factors, constraints and transmission capacity investment. Therefore, this potential benefit must be looked at cautiously.

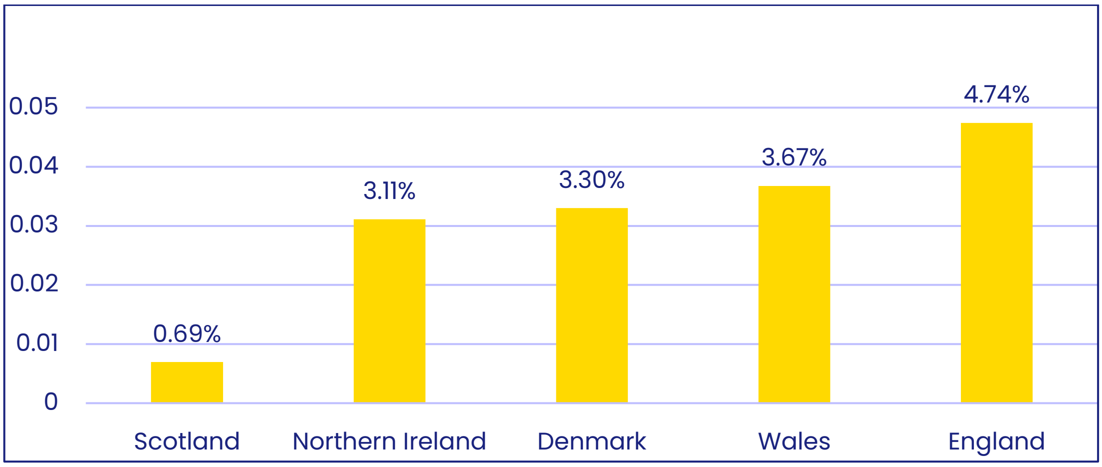
[4] https://www.theccc.org.uk/wp-content/uploads/2019/05/Net-Zero-Technical-report-CCC.pdf

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?

No comment.

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?

Ofgem should not be picking technology winners and losers. The proposed reforms appear to embrace the incorrect assumption that solar generation projects are not viable in the north of England and Scotland. This is flatly refuted by the facts. There are currently over 1.2GW of solar projects in the planning pipeline for Scotland alone. Further, Northern Ireland and Denmark, which are on roughly the same latitude as Scotland, have four times as much solar generation capacity installed.



This shows that preconceptions about insolation levels are unfounded, and that there are broader structural barriers to PV deployment in the north which the proposed TNUoS reforms would only exacerbate.

Our work has shown that solar PV, particularly in combination with storage, can deliver significant system level benefits – reducing the evening spike in demand, mitigating the strain on the network, and reducing the need for costly reinforcement.[5] Any reforms to charging arrangements should be designed to facilitate the deployment of PV generation across the UK, which the proposed TNUoS reforms would have the opposite impact, constraining PV generation to the south of England and Wales, and further reducing locational options for PV sites.

Fundamentally, there does not seem to have been enough thought given to how the proposed reforms would undermine the expansion of the solar industry in the north of

[5] https://solarenergyuk.org/resource/smart-solar-homes/

England and Scotland. There appears to be an assumption that much of the power generated will be exported south, when in fact it would go directly to local distribution networks. This assumption, along with the cost of connection, is a major barrier to solar deployment in Scotland.

Ofgem should also consider how solar can make better use of the transmission network that has been built for offshore wind to maximise utilisation of available capacity rather than it being reserved for a few offshore wind farms. Again, we would point to the synergies between wind and solar generation profiles.

General

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.