Email to:  
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30 July 2021

To whom it may concern,

**Access and Forward-looking Charges Significant Code Review: Consultation on Minded to Positions**

Scottish Renewables is the voice of Scotland’s renewable energy industry, working to grow the sector and sustain its position at the forefront of the global clean energy transition. We represent around 260 organisations across the full range of renewable energy technologies in Scotland and around the world, ranging from energy suppliers, operators and manufacturers to small developers, installers, and community groups, as well as companies throughout the supply chain.

In responding to this consultation, we would like to draw your attention to the following points:

* Key point 1
* Key point 2
* Key point 3
* xxx

Scottish Renewables would be keen to engage further with this agenda and would be happy to discuss our response in more detail.

Yours sincerely,

Text, letter

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Angeles Sandoval

**Policy Manager**

Scottish Renewables

**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 Ofgem’s proposal of removing the contribution to reinforcement for demand connections and reduce it for generation. We think that this new arrangement will send an effective signal for network users and may speed up the roll-out of low carbon technologies.

However, it is difficult to assess what the net outcome will be without having clear details about what will happen with DUoS. Ofgem states that they are still considering policy options for DUoS charging structure and the current assessment of the connection charging proposals is based on the assumption of either no or little change to DUoS.

**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?**

The current “shallow-ish” connection boundary incentivises connection in locations which do not require reinforcement. We think that this approach sends ineffective signals to network users which cause them to connect based on avoiding reinforcement charges rather than where the capacity is really needed. This will constrain the roll out of low carbon technologies and the increased investment we will need to electrify heat and transport.

Scottish Renewables has evidenced[[1]](#footnote-1) that a move to a shallow connection boundary arrangement could address this problem, so new generators are only required to pay for direct cost of connection. A shallower connection boundary could also be combined with more granular DUoS charges, which would provide a price signal to incentivise connections in network locations where additional generation would not require reinforcement, and network use at times when more spare capacity is available. However, we note that shallow connection charging needs to be introduced in a way that protects the rights of existing users, who could otherwise lose out via higher DUoS charges due to the effect of new connectees on the network.

Ofgem is proposing a hybrid approach that would remove the contribution to reinforcement for demand (a “shallow” connection charging boundary) and reduce it for generation (a “shallower” connection charging boundary than exists today). We think that this is a sensible approach, mainly based in the ‘Quantitative analysis from CEPA-TNEI report that accompanies this consultation.

The CEPA-TNEI report assesses the cost benefits of a completely shallow option, a modest reform which amends the voltage rule, and a hybrid arrangement (preferred by Ofgem) in which demand customers would face a shallow connection charge but generation customers would face the amended voltage rule. The first option shows around £1.4 billion of consumer welfare disbenefit if introduced in isolation. The second option shows a reduction in the disbenefits to £0.3 billion and the last option leads to disbenefits of around £0.4 billion. Therefore, considering this analysis, we agreed with Ofgem on this point. We think that a hybrid approach will provide balance between removing barriers, encouraging more efficient system development and supporting net zero at least cost.

However, we would like to highlight that this approach must be looked at carefully with the policy options of DUoS charging structure that Ofgem is still considering. Additionally, we think that Ofgem should consider the option of grandfathering the rights of existing connectees. Previously, connectees would have paid for reinforcements. If new users connect without paying such costs under a shallower connection boundary, these costs will be reflected in network charges, which will be a negative externality on existing users (unless locational elements of DUoS offset the reduced connection costs).

**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 we mentioned in our answer to question 3b, the current arrangements represent a barrier for current network users. We think that this new proposal will facilitate efficient development and investment in distribution network, allowing network users to invest considering anticipated network needs.

We also think that this proposal could have some positive consequences to stimulate the use of flexibility across DNOs, since they can find more efficient ways of funding the work needed. The CEPA-TNEI report that comes alongside the consultation, suggests that the emergence of flexibility services could help to mitigate some impacts of a shallower connection boundary if changes to connection policy do stimulate the emergence of flexibility markets. Therefore, we can see that this proposal combined with a set of policies that push the emergence of flexibility services across the UK, could have positive impact in the smart and flexibly energy system that we expect to have by 2030.

**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?**

**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?**

**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?**

We think that these changes must be considered separately alongside a wider review of TNUoS. 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?**

**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?**

**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?**

**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?**

**Response to Q4a-4b**

We welcomed this proposal. We think that a better defined non-firm access will allow some users to be able to connect more quickly due to better management of curtailment risks. Similarly, a new time profiled access choices will bring some benefits in relation to the speed and simplicity of connections. We note that this proposal could allow some parties to connect more quickly, if they can clearly signal that they do not require capacity in periods of peak network loading. However, Ofgem is not proposing to do anything with DUoS, which makes it very difficult to assess the final outcomes of this proposal.

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

**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)?**

**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?**

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

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

**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?**

The current TNUoS regime is not fit for purpose, thus the proposal about charging SDG in the same way as large transmission generators is not the best way to go forward.

The following documentsfrom SSEN[[2]](#footnote-2) and Scottish Renewables[[3]](#footnote-3),demonstrate that the current charging methodology guiding TNUoS is not fit for purpose to meet either the Scottish Government or UK Government’s net zero climate targets. The way that TNUoS is designed encourages generators to locate close to the demand. This was appropriate for a fossil fuel-based system but now leads to disproportional charges by location as we move to a renewables-based system. Additionally, the variability of TNUoS charging regime creates uncertainty that leads to increasing risk margins for developers, ultimately increasing costs that will be placed onto energy consumers to pay.

**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?**

The current proposal will apply TNUoS charges to all generators, except for <1MW SDG, which would continue to face the embedded export tariff (EET) with the cap removed.

We would like to note that removing the cap of generators below 1 MW would affect producers 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 faces embedded export charges equal to 0 £/kW, by 2024 and 2040 this charge will be around 36.5 and 80.6 £/kW. This sends a perverse signal to generators for not generating at Triads periods.

5MW is maybe more appropriate?

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

**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?**

**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?**

Yes, we support the option that **delays implementation until a wider review of TNUoS has happened**. The current proposal as it is, will only exacerbate the TNUoS cost for Scotland’s generators, affecting specifically the installation of onshore wind capacity, a resource largely located in Scotland.

It is our view that **grandfathering** projects could be an option 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 as a consequence higher cost of capital for projects. In this context, 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 producersare 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 choices that exist in reality.

The model shows that over the period to 2040 technologies such as onshore wind, solar, biomass and hydro in the north of Scotland have losses (in terms of NPV) of around -369, -318.9, -284.5 and -492£/kW respectively. This will particularly affect the deployment of onshore wind, a resource that is mostly located in Scotland and is needed to achieve our climate targets. According to the 2021 FES report[[4]](#footnote-4), in the consumer transformation scenario (the main scenario taken by Ofgem in its analysis) we will need 44GW of onshore wind by 2050 and most of this is expected to be connected to distribution networks. Ofgem’s model does not explain how this technology is expected to be located in southern areas if most of the resource is in the north and it does not explain if this will have any implications on security of supply either. We think that this is something that Ofgem must address in the model

In addition, the 2021 FES report states that capacity on the electricity transmission network to move power across the country is an important factor. Today we can see high levels of power exported from Scotland into England at times of high wind generation, and in future we expect to see further significant power flows. These will become increasingly important as we move toward a more decarbonised energy system, with many generation sources located further from demand than previously and where onshore wind in Scotland and offshore wind in the North Sea are clear examples.

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.

**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?**

**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?**

It is our view that many issues are not included in the current charging proposal from this consultation that Ofgem should consider in the analysis of the future role of network charges. These include:

1. Locational allocation of capacity.

As we mentioned previously, there are key determinants of the location of renewable capacity that are not captured in this model, mainly related to locational decision of investors that include load factors, grid constraints and transmission capacity investments. We recommend that the impact assessment considers the overall impact of benefits including locational factors such as load factors, price volatility and wind capture prices. These are factors that we think are important to consider as the quantitative potential benefit could be highly affected by them.

1. The benefits of a diverse mix of generation

The current proposal incentivises locating all the renewable generation in the south of the UK, with much higher benefits for the development of solar energy. This charging system is incompatible with the decentralised energy system of the future that the UK Government envisioned in the 2020 Energy White Paper[[5]](#footnote-5). Regulation does not exist separate to policy. If the Government’s preference is to increase and decentralise the deployment of cost-effective renewables and flexibility as a key element of achieving the net-zero target, regulatory processes and the charging regime must not constrain this.

The UK has diverse renewable resources that can be deployed across the whole country, with one of the best potentials for onshore and offshore wind. Energy diversification is important to provide energy security and long-term sustainability transitions. The UK has a strong economy and so requires a variety of energy sources for industrial production, electricity production, transport, and domestic use. The proposal from Ofgem is not taking into account the benefits of a diverse energy mix and the implications that not considering this could have on security of supply.

1. Planning regime across the country

Today, the planning and consenting system for onshore wind developers is more favourable in Scotland than in England and Wales. While the Scottish Government’s Onshore Wind Policy Statement[[6]](#footnote-6) reaffirms commitment to enable the development of onshore wind in the country, the current planning regime in England has been shown to be more challenging and hostile to the deployment of onshore wind. This is concerning as the FES consumer transformation scenario from National Grid (the main scenario taken by Ofgem in its analysis) shows that we will need embedded onshore wind generation across the whole country. Thus, if the current planning system in England is not favourable for the deployment of onshore wind, it is not clear how we can locate all the onshore wind capacity in the south. This, added to the fact that most of the resource is located in Scotland. We believe that this is something that Ofgem must address in its proposal because again there is huge contradiction between regulation and government policies.

1. The impact on repowering decisions.

The model has not sufficiently identified the impact on repowering decisions. Currently, Scotland has 60% of the UK’s onshore wind capacity and by 2035 many operational projects will reach the end of their consented period, requiring reconsenting and repowering with the latest turbines. Repowering and new sites will both be needed to achieve net zero.

In the consultation document, Ofgem recognises there is a risk that if existing generators facing significant increases in TNUoS charges (up to £30/kW) choose not to repower and alternative generators are not able to internalise the impact, then some network assets built to provide capacity will become stranded. This is concerning because the ‘quantitative analysis of Ofgem options’ illustrates that over the period between 2024 and 2040, distribution-connected onshore wind will have losses of -369 and -226.4 £/kW (in terms of NPV) in the north and south of Scotland respectively. This will clearly demotivate any repowering decisions, reducing our ability to reach net zero.

1. Increased risk profile for developers

The current proposal incentivises new renewable projects to pass the cost through higher CfDs prices, but existing renewable projects do not have the chance to do this, which increases the risk profile for developers. Furthermore, it is important to highlight that customers do not end up obtaining a saving, potentially they can get cheaper TNUoS in exchange for more expensive CfDs.

1. TNUoS reforming timeline

We think that the timeline to reform TNUoS could be a challenge, especially considering the short time we have to meet our 2030 targets. This creates ongoing uncertainty for developers and their investors, putting at risk the opportunity to deliver net zero at least cost. We recommend that Ofgem takes into account that we need this reform, but we also need to accelerate the timeline that this process will take.

**General question**

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

We would like to highlight the key reasons why the current TNUoS regime is not fit for purpose and why urgent action is needed to change it. We believe that regulation should move forward at pace to facilitate the deliveries of government commitments and it should not constrain those in any case.

1. TNUoS no longer does what it was designed to do

Back in 1992, the charging system was designed to provide clear signals to the energy market to incentivise developers to build fossil fuel power stations close to demand. Today, as we move to a smart, decentralised and more decarbonised energy system, a fairer system which balances the strengths of different parts of the UK is needed.

The renewables industry has led rapid cost reduction over the last decade, with developers reducing the costs at every stage from finance and procurement to design and delivery. However, TNUoS is a cost that developers cannot control. This means that as the cost of a unit of renewable electricity has come down, the proportion of that cost represented by TNUoS has gone up significantly. This is in combination with a predicted substantial rise in transmission charges over the next five years, with the differential between northern and southern projects also amplifying. According to a recent report by SSEN Transmission, a wind farm in the north of Scotland currently pays £5.50 per unit of energy as part of the locational TNUoS charges compared to an equivalent wind farm in Wales getting paid £2.80 per unit[[7]](#footnote-7). This increased cost that TNUoS imposes makes Scottish projects uncompetitive, encouraging generators to install projects in the south of the UK without considering where the best renewable resources are located to deliver the lowest cost pathway to achieving net zero. This system does not match the decentralised, smart and decarbonised energy system of the future.

1. TNUoS is affecting consumer bills

Due to the pay-as-clear mechanism within the CfD, there is an impact on consumer interests as cheaper southern projects will have their strike price brought up to meet more expensive northern projects.

Along with amplified locational signals, volatile and unpredictable TNUoS charges are also harming renewable investment. In research conducted by SSEN Transmission they found:

* Generators see swings in their TNUoS charges typically over 50% up or down each year. For the nine generators studied, year-on-year changes have been between +774% and -2090%
* Charges are unpredictable – Using National Grid’s own data, the average forecast error under-estimated the actual charge by one third.

This volatility is in sharp contrast to the total revenue allowed of the TOs that TNUoS charges are set to recover. The cumulative allowed revenue of NGET, SPEN and SSEN Transmission has been stable, within 5% of £2.5 billion, over the past five years. Investors need cost certainty and clear, forecastable TNUoS when planning and delivering long-term investments at lowest cost of the UK consumer. We also note that price volatility is a significant challenge for operational sites, where projects have been built and financed at a specific point in time based on the best view of TNUoS. These projects cannot react to changes in locational signals and therefore volatility in TNUoS costs simply adds risk to the projects. Volatility and unpredictability are not unique to Scotland but experienced by all generators regardless of technology or location. This uncertainty leads to increasing risk margins for developers, ultimately increasing costs that will be passed onto consumers.

1. TNUoS is not aligned with net zero

The transmission charging methodology is a complex combination of factors that must now include the need to deliver net zero alongside other electricity system and policy goals. Without a rethink, we believe that the direction of travel in network charging could result in a major barrier to delivering net zero. As discussed previously, there is a strong case to review the transmission charging methodology to ensure that the development of renewables is not discouraged where resources are most abundant. The need for review is even more pronounced given the ongoing review and reform of the offshore transmission arrangements.

To achieve our respective net-zero targets, we will need a steep increase in renewable energy installation by 2050 in all parts of the UK, not just the south. According to the Sixth Carbon Budget from the CCC, the renewable deployment by 2050 should be between 95 and 125GW of offshore wind, between 75 and 85GW of solar PV, and between 30 and 35GW of onshore wind. Scotland has the resources to supply a big proportion of this deployment, but with TNUoS disadvantaging Scottish projects in the CfD, there is a risk these projects may not be built, reducing our ability to reach net-zero. It is important to move forward at pace with a strategic review about how best to use regulation to allow a proportional deployment of renewable energy across the whole UK.

1. TNUoS is harming Scotland’s economy

The extra cost of paying electricity transmission charges makes Scottish projects less competitive in the CfD auction process. 1GW of renewable electricity generation means £133 million to the Scottish economy, therefore fewer projects mean the money which the private sector must invest to meet net zero will be spent elsewhere in the UK. This can be reflected in auction round AR1[[8]](#footnote-8), AR2[[9]](#footnote-9) and AR3[[10]](#footnote-10) available through BEIS website (see table below), which shows that the capacity awarded to Scottish projects has decreased from 39 % in AR1 to 9% in AR3.

|  |  |  |  |
| --- | --- | --- | --- |
| **Auction Round** | **Total capacity awarded (MW)** | **Capacity of Scottish projects (MW)** | **% capacity awarded to Scottish projects** |
| AR1 | 1162 | 448 | **39%** |
| AR2 | 3196 | 950 | **30%** |
| AR3 | 5466 | 466 | **9%** |

This situation is expected to get worse without any action to the current TNUoS regime. According to National Grid ESO tariffs[[11]](#footnote-11), the TNUoS charges in Scotland have increased from 11 £/kW from 2016 to 26.35 £/kW in 2021 and members of Scottish Renewables who are been doing their own analysis predict that the situation will get worse without any action.

1. [Grid charging reforms: New report by Baringa consultants for SR/RUK (scottishrenewables.com)](https://www.scottishrenewables.com/publications/598-grid-charging-reforms-new-report-by-baringa-consultants-for-srruk) [↑](#footnote-ref-1)
2. <https://www.ssen-transmission.co.uk/media/5261/ssen-transmission-tnuos-paper-february-2021.pdf> [↑](#footnote-ref-2)
3. <https://www.scottishrenewables.com/publications/861-tnuos-key-points-and-explainer> [↑](#footnote-ref-3)
4. <https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021> [↑](#footnote-ref-4)
5. <https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future> [↑](#footnote-ref-5)
6. <https://www.gov.scot/publications/onshore-wind-policy-statement-9781788515283/> [↑](#footnote-ref-6)
7. <https://www.ssen-transmission.co.uk/news-views/articles/2021/2/ssen-transmission-calls-for-reform-of-unfair-and-volatile-charging-regime/> [↑](#footnote-ref-7)
8. [Contracts for Difference (CFD) Allocation Round One Outcome - GOV.UK (www.gov.uk)](https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-one-outcome) [↑](#footnote-ref-8)
9. [Contracts for Difference (CFD) Second Allocation Round Results - GOV.UK (www.gov.uk)](https://www.gov.uk/government/publications/contracts-for-difference-cfd-second-allocation-round-results) [↑](#footnote-ref-9)
10. [Contracts for Difference (CfD) Allocation Round 3: results - GOV.UK (www.gov.uk)](https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-3-results) [↑](#footnote-ref-10)
11. <https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges> [↑](#footnote-ref-11)