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

[Call for evidence]

Independent Renewable Energy Generators Group (IREGG) response

Introduction

IREGG was established in 2012 and is a partnership of independent renewable energy generators and developers as well as the manufacturer Enercon which have together invested hundreds of millions of pounds in UK energy infrastructure including in Scotland.

IREGG members include:

- **Falck Renewables:** a renewable energy company with headquarters in Milan, Italy, with two offices and a significant number of operational and development projects in the UK.
- **Banks:** a County Durham-headquartered renewables business operating and developing wind and solar projects.
- **BayWa**: a German headquartered solar, wind, and bioenergy company.
- **ERG**: an Italy-based onshore wind and solar developer and operator with assets across Europe.
- **Infinergy**: an energy company, developing large, medium and small-scale onshore wind and solar PV projects in the UK, the Netherlands and Australia.
- **Enercon**: a German based wind turbine manufacturer and one of the world's leading companies in the wind energy industry.
- **Fred. Olsen Renewables**: a Norwegian-headquartered onshore and offshore wind business with currently ten operational windfarms in the UK (Scotland) and several more at consent stage. The group includes Scotland's Natural Power consultants and offshore specialists Fred. Olsen Ocean.
- **Ventient Energy**: a pan-European renewable energy business and one of the largest independent generators of onshore wind energy in Europe.

Summary

IREGG's response is limited to Section 5: Ofgem proposals for TNUoS charging for Small Distributed Generation. IREGG has engaged extensively on the proposals, both directly with Ofgem and BEIS, and has made comments on the shortcomings of the methodology underpinning the rationale for proposals. There are significant issues with these, contradicting the stated aim of achieving Net Zero at least cost.

IREGG therefore argues that the most sensible course of action includes:

- Pausing the proposed application of TNUoS to SDG, while long-term plans for TNUoS are developed, given the flaws in the current TNUoS calculation and more fundamentally flaws in the principles upon which TNUoS is based.

- Undertaking wider TNUoS reform to better align with net-zero goals while implementing "quick fixes" in the interim in order to counteract the negative effects of the recent changes to charging for transmission connected generators (via the TCR).

Consultation Questions

IREGG's response will be limited to Section 5: Ofgem proposals for TNUoS charging for Small Distributed Generation

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?

1. It appears that this question demonstrates Ofgem's inadvertent overly-narrow focus on prior work, which set the goal of ensuring SDG pays higher charges, rather than taking a wider, more holistic review of TNUoS in the round. It would be more sensible to review consistency of charging, including consistency between GB and the rest of Europe, and ensuring fairness of the calculation methodology, rather than jeopardising Net Zero with a narrow focus on certain technology classes.
2. As interconnectors contribute to flows on the transmission network, it could be stated that they should also be charged TNUoS to ensure consistency of charging with other transmission-connected forms of capacity. Whilst we are not calling for TNUoS to be levied on interconnectors, this highlights an obvious market distortion caused by the GB transmission charging regime, with interconnectors (and continental generation) having a clear competitive advantage over GB capacity in wholesale and capacity markets as a result. This not only highlights Ofgem's inconsistency, in that it ignores the distortions that don't fit within a narrow ideological framework, but it also shows that the growing misalignment in charging arrangements between GB and the rest of Europe is an increasingly pressing issue, and needs addressing.
3. Furthermore, given the flawed assumptions that Ofgem's modelling has been required to make, it is not clear whether the proposed penalty charges on Scottish investment via charges to SDGs will have an impact that aligns with Ofgem's objective to support Net Zero at least overall cost.
4. Moreover, the picture painted in this consultation of the contribution of SDG to flows is a distortion of the actual physics and economics of the electricity system. Ofgem should be well aware of the misconception that TNUoS rates are inherently linked to the distance between a generator and the main centres of demand (i.e. the south east of England), but it bears repeating that this is not the case. The distance from London to Newcastle is the same as that from London to Falmouth (280 miles), and yet a wind farm located in the north-east of England would expect to pay TNUoS of £6000/MW per year in 2021, while the same wind farm located in Cornwall would receive a credit of £2300/MW per year in 2021. Imposing these distortions on SDG does not promote consistency, it accentuates inconsistency, to the detriment of Net Zero.
5. While electricity generated a long way from demand centres incurs some transmission losses, this is already explicitly accounted for by Elexon in the settlement process via the use of zonal Transmission Loss Factors (TLF). This has

been the case since Ofgem authorised P350 in 2017, following the CMA investigation of the energy market. Generators in Scotland therefore already face higher TLFs than generators in the south of England to account for the greater transmission distances, and this is completely separate to the TNUoS calculation methodology. We do not object to Ofgem's high level principle of achieving consistency between generators, but the contention that imposing TNUoS on SDG promotes consistency is flawed. This is because the current levels of TNUoS are based on flawed modelling (which has been acknowledged by Ofgem) and more rigorous assessments of the cost-benefit analysis proves that there would be a net-disbenefit to this approach. It should further be noted that the CMA estimated that the benefits of moving to a zonal transmission loss system only amount to around £0.50 per household per year. It is further worth stressing that whether SDG should pay TNUoS should not be seen as a fix to address levels of 'constraint' as TNUoS rates are not inherently linked to levels of constraint. Constraints may occur on boundaries and circuits across the GB network, many which are part of the day-to-day management of the grid within operational limits and are therefore paid for through BSUoS, not TNUoS.

6. Constraints are therefore not only an issue caused by Scottish wind generation. Nor should they be seen solely as a market failure. Building a grid that required no constraints would require significant over-investment, so a certain level of constraint represents a commercial decision by the ESO, particularly in the context of the requirement to rapidly build large amounts of low carbon generation.

7. This view was actively supported by DECC's endorsement of the enduring Connect and Manage (C&M) approach to granting generation access to the network before all wider reinforcement has taken place. Over the longer term, the ESO's strategic planning clearly forecasts that the growth of generation in Scotland will require significant reinforcement of many of the major boundaries to avoid an uneconomic level of constraints in the coming decade. However, the same plans also show that the LE1 boundary in the south-east of England will also be suffering equally severe levels of constraint by 2030.

8. There is a clear distortion, therefore, between the rates of TNUoS paid by generators, and the long-term requirement for network reinforcement in a particular region, (with generation in London and surrounding areas receiving a TNUoS credit), and imposing that distorted TNUoS charge on SDG would therefore exacerbate inconsistency in the system. It would also add to the costs of Net Zero for billpayers.

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?

9. Penalising local Scottish communities who have invested in local green energy schemes by imposing charges on them from which generation imported from the EU via interconnectors is exempted can only undermine the work that the UK and Scottish governments have been undertaking to build public support for investment in Net Zero.

10. We would favour the development of the most level playing field – and this would entail applying the same framework to as small a threshold of generation as can be practically achieved. A relevant technical threshold can be found in ENA Engineering Recommendations G98 and G99 – where G98 applies to generators of up to 16A per phase, and G99 applies to anything larger.

11. A 1MW threshold, meanwhile, does have *some* merit but we would note certain issues arising from this. CEPA's analysis was undertaken under the assumption that where network costs rise for renewable generators, they are able to mitigate this via an increase in policy costs (via higher CfD prices). As generation under 5MW is not eligible for the CfD, they would not be able to recoup the additional higher costs. Nor, given the magnitude of additional costs that Ofgem is proposing to impose on Scottish generation, are such generators likely to be able to offset these via additional incremental revenues in the Balancing Mechanism. We would also note that these generators are far more likely to be community groups, for example, rather than more sophisticated developers, and may therefore be less able to absorb the hit of having TNUoS imposed on them, nor be able to mitigate it through a diverse wider portfolio. The negative impact on generation between 1-5MW has therefore not been properly accounted for in the modelling.

12. With regards to interconnectors, under EU regulations, (Regulation EC No 714/2009 – the `Third Energy Package'), these are defined as neither generation nor final demand. Generation imported into the GB network via interconnectors is therefore excluded from liability for TNUoS or BSUoS payments.

13. Given that the UK has now left the EU, imposing penalty charges on Scottish generation that exports power to England, a charge exempted for EU generation exporting power to England, creates unfavourable optics at a time when the government is seeking investment from international sovereign wealth funds in UK green infrastructure including in Scotland.

14. Great Britain's average TNUoS level is five times higher at an average level than other European countries, meaning that Scottish generation is many multiples higher than that. Charges in Scotland (averaging £6.42/MWh in 2019, and being just under £10/MWh in the North) are a significant and gross outlier compared to neighbouring countries (averaging below €0.50/MWh across Europe), encouraging investment outside of GB [see ENTSO-E overview of transmission tariffs].

15. Scottish generation has only recently become fully integrated into the GB transmission system, via Ofgem's BETTA process which re-designated the former Anglo-Scottish interconnector as "normal" GB transmission. Given that Ofgem rules state that interconnectors that go into England are not liable to pay transmission charges, it is inevitable that proponents of independence will query the apparent double standard which renders Scottish generation less competitive than generation imported from, for example, the Netherlands.

16. The Prime Minister has spoken of harnessing Scotland's wind to make the UK the Saudi Arabia of wind power, and a promise of BETTA was that Scottish energy generation would be better placed to export but Ofgem's Scottish locational charging penalties have the opposite effect. In so doing, it will raise the level of

political risk for investment in Scotland, and therefore its cost of capital, further undermining the competitiveness of Scottish energy.

17. It should be noted that network charging is becoming an increasingly salient issue in the debate on Scottish independence, as shown when Scotland's First Minister Nicola Sturgeon raised concerns over it at the Scottish Renewables conference in March. Any policy created by Ofgem can have, or can be perceived to have, a constitutional impact given that policies form the parameters of how business is conducted across GB.

18. A less distorting threshold would ensure that Scottish power generation that exports to England is not subjected to penalty charges from which EU generation is exempted simply because the EU generation transmission connection to England is still classified by Ofgem as an interconnector while the Anglo-Scottish interconnector was reclassified by Ofgem as not being an interconnector some fifteen years ago.

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

19. While the premise of the question is understandable it does not per se follow from this that different locational rules should be applied.

20. This is the case particularly when considering the fact that SDG 'driving flows on the network' only occur when the Grid Supply Point (GSP) is exporting. Given this does not happen all the time, one might argue the load factor that goes into the wider locational charge for SDG should be much lower to reflect intermittence. Where they are not exporting out of the GSP it could even be argued they might not be TNUoS-liable.

21. Overall, however, the main difference is in commercial and regulatory arrangements. A goal should be to simplify the system, making it easier to manage, easier to make quick adjustments should distortions arise during the energy transition, and easier for users to understand how changes might impact them. The more complex the commercial systems are, the more complex the definitions are to dictate charging methodology, the more significant the changes are between connection levels and locations, the easier it is for distortions to emerge and for unintended consequences to happen as layers of adjustments get added over time.

22. It is therefore clear that the current TNUoS signal is too strong and a reform of TNUoS is needed before a case for charging SDG may be considered.

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?

23. None of Ofgem's options address significant charging distortions – they make them worse.

24. A far more significant distortion, which Ofgem's options would exacerbate, is the fact that TNUoS is not actually reflective of Transmission Owner spend, as it models a representative cost of new 400kV pylon line, when in reality additional grid capacity is provided otherwise: through commercial services, flexibility, geographic diversification and up-rating of existing lines.

   - Moreover, generator transmission charges in Scotland have risen roughly 250% in a decade when transmission spend has decreased 7% in real terms.

   - The resulting network charging differential (Scotland to south England) of around £10/MWh will be the primary differentiator in forthcoming CfD auctions for onshore renewables that may clear below £40/MWh – giving credits which subsidise less-efficient plants in England, and increasing the cost of the CfD scheme needed to deliver sufficient renewables across GB.

25. It seems perhaps that the role of TNUoS has been distorted, in that is not meant to reflect the cost of getting energy from A-B, as zonal transmission energy losses are paid separately by generators, deducted directly at the meter, while the sunk cost of pre-existing network is spread among final demand users.

26. Ofgem's options exacerbate several charging distortions. They include:

   - The lack of correlation between the level of network charges and the actual volume of investment in network reinforcement and improvement.

   - The volatility of the charges as compared to the actual levels of network investment.

   - The imposition of penalty charges on power generation located in Scotland that exports power to customers in England as compared to equivalent and identical power generation plants located in the EU that export power to England are exempted.

   - The fact that Ofgem's network charging framework penalty charges levied on Scottish green energy are used, not to invest in future grid, but to give credit subsidies to fossil fuel power stations in southern England.

   - The fact that Ofgem's plans do nothing to address the far more important distortion between the onerous levels of transmission charges that GB generators pay on average compared to those in neighbouring markets (five times higher).

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?

27. We welcome the consideration of whether the wider TNUoS methodology will remain fit-for-purpose and we are strongly supportive of such a review, in parallel with any necessary quick-fixes to the methodology.

28. In order to highlight why such a consideration of TNUoS methodology is welcome, we note the modelled tariffs to 2040, showing the Wider Circuit TNUoS capacity charge averaged to each DNO region (quantitative analysis document, p29 Table 5.3), which stakeholders may infer as a direction of travel for the status quo methodology. The outcomes are a strong signal to incentivise fossil-fuel generation anywhere in England or Wales, and even to pay TNUoS credits to fossil-fuel generation throughout Scotland, despite the principles which TNUoS was designed to deliver. On the other hand, the only generation making payments for wider TNUoS is low carbon conventional and variable renewables in Scotland alone. These outcomes are hard to reconcile against cost-reflectivity, nor against reasonable regulatory uncertainty for existing generators. Above all, these outcomes are hard to reconcile with the deployment of variable renewables required to meet net-zero pathways. The published table is summarised below for illustration:

Dist. zone	Capacity charge £/kW, Conventional generators	Capacity charge £/kW, Low Carbon generators	Capacity charge £/kW, Intermittent generators
1	-3.56	54.02	54.46
2	-5.72	29.17	29.91
3	-7.67	-0.24	-0.17
4	-8.32	-4.55	-4.26
5	-8.97	-8.86	-8.35
6	-8.97	-8.86	-8.35
7	-13.55	-18.44	-13.86
8	-13.55	-18.44	-13.86
9	-13.17	-16.37	-12.04
10	-13.55	-18.44	-13.86
11	-14.69	-19.48	-13.74
12	-13.55	-18.44	-13.86
13	-14.69	-19.48	-13.74
14	-14.69	-19.48	-13.74

Ofgem July 2021 - Access & Forward Looking Charges SCR Minded-To Publication - document (3) CEPA-TNEI Quantitative Analysis, page 29 Table 5.3

We believe that these tariff signals are indicative of the need for a wider review of TNUoS.

29. In general, however, the most important thing will be to ensure that both existing and new Ofgem policy does not undermine Net Zero, or add to the overall cost of bills in the medium to long term, given the new context, and different energy mix requirement, that Net Zero brings.

30. As the Climate Change Committee has underlined, UK Net Zero requires an uplift in the rate and scale of green energy deployment in GB. In that context it is surprising that Ofgem is even considering measures that, as the modelling undertaken for the impact assessment concedes, will have the opposite effect:

a. "The largest negative impact that we observe for onshore wind capacity is in north Scotland where we estimate a levelised revenue impact of approximately £9.57/MWh. This represents just over 20% of the LCOE estimates for larger onshore wind plant with capacity of greater than 51MW. It represents just over 10% of the LCOE of smaller onshore wind plant with capacity between 100 – 1,500kW. The impacts on capacity in south Scotland would be around 11% and 5.5% of LCOE for the larger and smaller representative capacities. We expect that impacts of this order of magnitude could be important in relation to investment decisions for an individual plant….In the case of repowering decisions in north Scotland, the net revenue impacts that we observe could represent up to 26% of LCOE for a repowering decision for an embedded onshore wind generator such that this could lead to a decision not to re-power for some projects."[1]

31. Repowering decisions will need to be taken on an increasing proportion of zero-carbon energy over the next few years. Ofgem's Chief Executive Jonathan Brearley has underlined that one of his primary objectives for Ofgem will be to "enable investment in the low carbon infrastructure needed to deliver net-zero". In the context of this clearly stated position, independent energy generators are keen to clarify the following outstanding points and questions for our investors.

    a. Investors are competing in a global market for low-cost finance. If the rate of return for GB energy generation is insufficient to meet the hurdle rate for those investors, generation will not be built or repowered.

    b. Ofgem's plans propose to increase the scope and scale of costs that generators would be required to pay for GB energy networks (costs which are already significantly beyond what generators pay in the vast majority of competing overseas energy markets, such as Germany).

    c. As such, when will an independent assessment be published which stress-tests the risk that Ofgem's plan could undermine the rate of return of GB generation relative to competing foreign generation, and lead to necessary GB investment being diverted to overseas low carbon energy generation or alternative competing asset classes with greater rates of return for equivalent commercial risk?

32. With regards to CEPA's analysis, we note that there is an error regarding the impact of Ofgem's plans on the viability of re-powering wind farms. CEPA contends that: 'Finally, while we do not have direct evidence of the costs of re-powering, Renewable UK suggests that this may allow for somewhere in the region of a 20% saving on LCOE compared to investment in new capacity.' In fact, Renewable UK's report does not state that at all, rather it states that a repowered wind farm may achieve a 20-30% decrease in LCOE compared to the existing (much older) wind farm.[2] It does not imply a structural advantage that re-powering projects have over

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[1] CEPA-TNEI Report - Quantitative Analysis of Access SCR Options, p.42

[2] Renewable UK – Onshore Wind: The UK's Next Generation, p.17

new build wind farms, and the lack of re-powering remains a key risk of these reforms.

33. There is a clear incompatibility in strategy between the CEPA modelling underpinning the Impact Assessment and the shared ambitions of both the Prime Minister and the Scottish government to boost zero carbon energy generation in Scotland:

    a. The analysis states: "However, we do observe a change in the choice of location for embedded renewable generators… the clearest trend that we observe is for new embedded onshore wind capacity that chooses to locate in Scotland under the counterfactual to instead locate in north and central England under the TNUoS reform option".[3]

    b. CEPA adds that "our modelling shows that the overall net revenue impacts on renewable producers as a whole are negative. In particular, we find that TNUoS reforms may result in a decrease in investment signals for distribution connected onshore wind capacity in Scotland".[4]

    c. Indeed, CEPA highlights the risk to the rate and scale of GB green energy deployment: "we might expect the negative impacts on the revenues of Scottish embedded onshore wind generators to drive a decrease in onshore wind investment in GB overall. This is because of the prevalence of onshore wind in Scotland relative to other parts of the country".[5]

34. In that context, ensuring a tight timescale for the review of TNUoS will be important. But as a transitional measure, Ofgem's plans to impose penalty charges on investment in Scotland need to be paused.

35. Nevertheless, this in itself will be insufficient to address the market distortions caused by the imposition of locational penalty charges on Scottish green energy projects. In contrast to CEPA's central case analysis, based on the Consumer Transformation FES Scenario which (erroneously) assumes the majority of new onshore wind out to 2050 is SDG, some 75% of the IREGG onshore wind forward pipeline is likely to be transmission-connected, and the distortions created by the way TNUoS is imposed as a locational discrimination - un-aligned with locational signals from other market influencers (e.g. the planning system and the availability of efficient generation resource) - is harmful to the least-cost path to Net Zero. "Quick fixes" to the present distortion of unduly exaggerated TNUoS penalty are therefore necessary to address the discrimination against Scottish investment within a viable timeframe. One such achievable quick fix would be to reduce the TNUoS Expansion Constant.

36. Further on the CEPA analysis, it should therefore be noted that flaws within the analysis include:

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[3] CEPA-TNEI Report - Quantitative Analysis of Access SCR Options, p.41
[4] CEPA-TNEI Report - Quantitative Analysis of Access SCR Options, p.43
[5] CEPA-TNEI Report - Quantitative Analysis of Access SCR Options, p.45

a. Misapplication of TNUoS credits.
b. Misapplication of revenue-replacement support costs.
c. Assumptions of sufficient and timely delivery pipeline in southern regions.
d. No adjustment of nameplate capacity to compensate for lower average load factor generation.
e. No recognition of geographic diversity benefits of variable renewables.
f. No adjustment of flexibility requirements to meet the less diverse and lower load factor generation mix.
g. Assumptions of zero early closures.

37. TNUoS credits have been misapplied in the modelling, mistakenly removing a signal to support triad generation by SDG. The sharper signal of TNUoS rather than the EET applied to southern generation would more likely see carbon emissions rise as a result of the proposed change. Quantitative Analysis (p.28) states "the reforms remove the operational incentive on embedded generators in the southern zones to export over expected Triad periods", whereas ESO pays TNUoS credits based on the average output during triad, retaining the triad signal. A smaller but similar-direction effect comes from applying Ofgem's TCR decision to floor demand locational charges at zero; even if un-floored, this would remove any corresponding EET charge applied to eligible (northern) SDG, mitigating the perverse signal to turn-off during triad, but also mitigating the claimed carbon emissions reduction.

38. Government support costs are mistakenly assumed to be tailored precisely to each region and separately to each generator technology (and without any delay which might impact deployment decisions). This is not representative of the CfD process, which has a single clearance price for all GB for a given 'pot' of technologies. This results in excess support for southern generation, which has the clearance price unduly lifted by the imperfect TNUoS locational signal; the resulting inefficiency will lead to a 'support costs' impact much larger than has been modelled.

39. It is also an optimistic assumption that the revenue 'loss' through TNUoS change will be perfectly offset in time and that there will be no investment delay and no risk premium adjustment as a result of the changes. The timing element has only downside risk for the quantitative analysis. On a related point, we would point out that it is optimistic to assume a seamless transition of pipeline projects from one region to another.

40. We note that geographic diversity of variable renewables has not been fully accounted for in the modelling. The TNUoS signal is to focus these renewables in closer proximity, in the centre and south of GB, which corresponds to greater volatility of output, leading to extremes of pricing and greater requirements for balancing actions (increased balancing costs to consumers) and greater requirements for flexibility (more nameplate capacity of battery storage or similar for each MW of variable renewables). When correctly factored in, this will act against the claimed net benefit.

41. Among the acknowledged modelling flaws, a few are worth drawing out as the implications are very material to the possibility of any net benefit coming from the proposed change:

42. According to the 2021 FES report, the consumer transformation scenario (the main scenario taken by Ofgem in its analysis) requires 44GW of onshore wind by 2050 and most of this is expected to be connected to distribution networks. The modelling acknowledges the limitations of pipeline and consent for this technology to be located in southern areas, and that most of the resource is in the north. Setting aside the considerable planning barriers, more southerly onshore wind is acknowledged to have lower factors on average. To maintain the energy output for net-zero pathways more nameplate capacity would be required, with corresponding increase in land use and support costs (typically paid per MW). We note in Ofgem's podcast on the Minded-To position the view that reduced levels of onshore wind may be accompanied by an increase in English solar capacity. Noting the roughly four times lower load factor of solar, this means significantly more nameplate capacity will be needed – which brings questions for total embodied carbon, of increased support costs (being typically paid per MW not MWh) and increased land requirements. We suggest it would be appropriate to quantify these outcomes to seriously test whether the changes can provide an overall net benefit.

43. Another significant element is the risk of early closure of operational renewables in Scotland as a result of the changes. Projects exiting previous support schemes (such as the RO) or ending their CfD agreement when faced with such tariffs as shown in Table 5.3 of the quantitative analysis (copied above) will see a challenging, and in a number of instances negative, cost-benefit for future maintenance, resulting in early closures. Both the unused local grid infrastructure and the negative effect on total deployment are missing from the quantitative analysis, which assumes existing renewables remain on the system without additional cost.

44. We conclude that a corrected quantitative analysis would show a reduced, likely negative net benefit, and that carbon emissions are more likely to rise than fall under the proposed changes. We are in full agreement that wider TNUoS needs to be reconsidered in terms of alignment with the UK's objectives for Net Zero and Ofgem's overall strategic direction. We agree that it would be appropriate to pause application of wider TNUoS to SDG while such reform is considered, mitigating change fatigue and undue volatility. We believe updated quantitative analysis would need to be done in light of the proposed TNUoS review and the points raised above before concluding on implementation of this charge for SDG.

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?

45. Not responding

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?

46. Significantly, in the Access and Forward Looking Access Review Impact Assessment, Ofgem asserts that:

    "4.1.2. Our principles based expectation is that removing the distortion will lead to:

    - Better locational decisions, as generation responds to signals and locates in zones that are closer to demand and less generation dominated.
    - A greater incentive to generation located in southern zones (i.e. closer to demand) to run at periods of high wholesale and balancing mechanism prices, rather than at times when there is a high likelihood of TNUoS credits
    - An increase in larger, more efficient, plant – specifically a move from small onshore wind to large onshore or offshore wind."[6]

47. This fails to reflect the risk warnings red flagged by Ofgem's own modelling paper by CEPA: "higher levels of investment in solar capacity in the south may replace onshore wind capacity. This would impact on dispatch profiles and therefore, in turn, on hourly wholesale market prices, constraints and investment".[7]

48. Given the flaws in the modelling, the assertion in paragraph 4.1.3. of the Impact assessment that imposing penalty charges on SDG in Scotland, "[…] should lead to less transmission network investment, lower constraint management costs, reduced curtailment of renewables and lower carbon emissions (due to decrease in dispatch of conventional tech for constraint management)"[8], does not appear to be properly evidenced.

49. The Impact Assessment asserts that Ofgem is seeking to discriminate between different types of green energy, and promote "specifically a move from small onshore wind to large onshore or offshore wind",[9] when that requires greater investment in Scotland and offshore from Scotland, where Ofgem is imposing ever greater Scottish locational penalties (e.g. under TCR) for all transmission connected energy generation. Moreover, it fails to acknowledge the role played in infrastructure development of the planning system. It is also explicitly contradicted by the modelling undertaken for Ofgem by CEPA which instead claims that it will lead instead to a move from onshore wind in Scotland to onshore wind and solar in England, which at the same time it concedes the planning system does not allow for on the scale necessary to reach Net Zero.

50. CEPA's analysis concedes that it was unable to model the implications of Ofgem's intention with regard to its interaction with the planning system, and the fact that the

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[6] Ofgem Access SCR - Impact Assessments, p.34
[7] CEPA-TNEI Report - Quantitative Analysis of Access SCR Options, p.45
[8] Ofgem Access SCR - Impact Assessments, p.34
[9] Ofgem Access SCR - Impact Assessments, p.34

planning system is working to an alignment that conflicts with Ofgem's approach, which will ensure distorted outcomes, but the risks for energy security are obvious: GB will need as much of its zero carbon energy aligned with maximising energy generation during the colder winter months when energy demand is greatest. As an example however, that time is when solar capacity is least able to deliver. It is surely at the very least imprudent to use modelling that assumes that solar capacity is able to compensate with no additional extra investment in battery storage to cope with the consequences of this approach.

51. It is notable that Ofgem states it is making a "principles-based expectation"[10] which implies that Ofgem's proposals were led by the modelling rather than driven by them. However, the significant and acknowledged modelling errors will likely have misled these expectations. There are examples of the Principles Based Decision (PBD) and modelling not being compatible with assumptions, as for example CEPA state, which throws the validity of 'real' modelled savings into question.

52. In paragraph 4.5, the impact assessment sets out what it refers to as the "hard to monetise impacts for preferred option". "The monetised results do not represent the full impact that we expect to see from this change, due to a combination of modelling limitations and wider impacts". [11] Given that these are "hard to monetise", it seems presumptuous to base regulatory change on the premise that the impacts of these points have been robustly assessed.

53. Paragraph 4.5.1 continues:

"We think our reforms will have the following hard-to-monetise impacts:

- Movement of generation capacity between the distribution and transmission networks (compared to a counterfactual without the reforms), as the incentive to connect smaller DG, rather than larger, more efficient, transmission connected generation is removed;
- The cost of implementing the changes, including amendments to commercial arrangements, which will depend on the implementation approach;
- Any potential impact of a change in the generation mix (e.g. an increase in solar instead of onshore wind), including on Security of Supply, although we do not expect there to be a significant impact."[12]

54. These are all major considerations for investors and for the efficiency of a net-zero energy system. Unless they have been monetised robustly then such impacts are potentially detrimental to the consumer interest.

55. The presumption that the planning system and contiguous land availability would simply allow equivalent wind or solar farms of far larger size to substitute for Scottish

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[10] Ofgem Access SCR - Impact Assessments, p.34
[11] Ofgem Access SCR - Impact Assessments, p.37
[12] Ofgem Access SCR - Impact Assessments, p.37

SDG that TNUoS penalty charges made uneconomic is a presumption without evidence and risks undermining Net Zero: to block what is investable on the presumption that investments can transfer to what the planning system renders unbuildable can only undermine the rate and scale of green energy deployment necessary for Net Zero.

56. The consequence of network penalty charging discriminating in favour of solar farms in England as against wind farms in Scotland within the CfD auctions will lead to less efficient generation mix and increase the cost of Net Zero. It is a clear false economy and there is no evidence that reduced network investment would compensate for that.

57. Specifically, on the points:

- Regarding "movement of generation capacity", we would contest this. While there are some benefits of scale, the primary driver of LCOE is the ability to deploy the latest technology (i.e 4MW+ hardware), and this is fundamentally a question of tip heights, and therefore planning consent. IREGG members are seeing these scale of machines now being planned and deployed as standard on the distribution grid as well as transmission, even in 1-3 turbine wind farms.

- Regarding the cost of "implementing the changes and amendments to commercial arrangements", we would stress that the former will be passed through to the consumer while the latter is questionable to assume in practice. The CfD does not have a provision to allow a change in strike price if TNUoS was to be applied and we would further challenge the idea that this is actionable by wind in Scotland – which are the hardest hit by the charge.

- On the third point we are concerned by the assertion that Ofgem "do not expect there to be a significant impact". It is evident that changing the generation mix has significant impact, which crucially has not been quantified in Ofgem's work. To illustrate:

    - The pipeline of onshore wind in Scotland = 12.9 GW; the pipeline of deliverable onshore wind in England = 0 GW.

    - The application of TNUoS to SDG will consequently lead to a loss of wind generation in Scotland, with the possibility for a likely rise of solar in England.

    - To achieve the equivalent output for the lost wind power, one will need at least 3.5x more GW due to the lower load factor.

    - Losing 12GW onshore wind would need the addition of 45GW of solar, the equivalent to covering all the land in Dorset and Derbyshire combined. Moreover, the latter will need additional GW of flexibility plant built, due to the profile of solar generation.

58. This higher concentration of renewables in the centre and south of the country would mean: 1) greater volatility in pricing (impacting consumers through higher financing of the cost of generation), 2) poorer technology capture prices (wind and solar) which means higher CfD costs and 3) further flexibility costs and build to offset the higher volatility in gross renewables output (due to lower geographic diversity in renewables).

59. Notwithstanding the above, the approach taken to locational charging under Forward Access Review and TCR reflects flawed principles. If the desire is to charge generation for the cost implications of longer network connections, then the energy transport costs (carrying power from A to B) are addressed separately by "Transmission Loss Multipliers". Given that TNUoS (on generators) is intended as a proxy for the cost of future grid build, and not that of current grid, the use of TNUoS as such a proxy is flawed in principle. If the principle of TNUoS is to send a locational signal to which generation can locationally react, then it is not clear, in principle, how it can be applied as a volatile charge to existing generation which, by definition, cannot relocate in response to an evolving locational signal. TNUoS is not sending signals to which generators can meaningfully react - once a generation asset is built it cannot move, and the unpredictability of future TNUoS makes it very hard to calculate future locational penalties when choosing sites.

60. Moreover, if the UK is to have locational charging as a 'signal', it is surely best to signal where generation makes most sense with regard to the grid that is needed in 2030-50, not the centralised fossil fuel grid that GB has inherited from the 1950s.

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

61. CEPA's modelling states that "we noted previously that our modelling takes generation capacity as exogenous and hence, assume that the generation capacity included in the FES is realised".[13]

62. The Impact Assessment sets out under paragraph 4.6. "Key assumptions/sensitivities/risks" that:

    a. The change in TNUoS charges is sufficient to outweigh other factors relevant to decision making, such as availability of renewable resources (e.g. wind).

    b. The FES are a robust reflection of potential future developments, including changes in planning permissions, in order to support achievement of net zero.

    c. More cost reflective signals will improve efficiency of siting decisions and dispatch.

[13] CEPA-TNEI Modelling Methodology - Access SCR, p.34

d. The extent to which charging SDG wider TNUoS generation charges will impact on repowering decisions for existing SDG.[14]

63. It is notable that these are described as assumptions/risks in that, as assumptions, they are defective and consequently pose risks.

64. Locational penalties that require wind farms not to locate in areas that are windy can only make them less efficient, or require their substitution by power sources such as UK solar which has a far lower average load factor and requires more flexibility support to meet winter peak demands. This makes Net Zero more costly.

65. It is by no means a robust assumption that the FES reflects changes in planning permissions: it does not and cannot pretend to. This makes Net Zero more costly. The FES documents themselves state: "Our four scenarios represent the credible range of uncertainty and are not themselves forecasts of expected pathways".[15]

66. As previously noted, the CT scenario that forms the 'central case' scenario of CEPA's analysis contains a capacity mix projection that is not reflective of current market trends (it has the highest levels of SDG wind of any scenario; assuming 63% of all new onshore wind to 2050 will be SDG, when analysis of the current market shows that the vast majority of planned capacity is transmission connected). Whilst such a scenario is clearly not realistic, it is the scenario most likely to show the clearest consumer benefit from a reform targeting SDG wind.

67. Given that TNUoS, as a recent SSEN paper[16] has set out in detail, is characterised by excessive volatility and a failure actually to reflect the costs of network investment, it is not clear how imposing TNUoS on SDG improves cost reflectivity, while the requirement imposed by Scottish locational penalty charges for siting decisions to consider the avoidance of locating in Scotland above all else cannot improve the efficiency of siting and dispatch for power plants that would be most efficiently sited onshore or offshore in Scotland. Ofgem's approved TNUoS penalty charging system increases both the volatility and the unpredictability of network charging, adding to costs, creating inefficiency by promoting sub-optimal generation locations, requiring more green energy generation in less efficient locations to deliver the power required, at greater cost to the consumer. The volatility alone adds £400m *per year* to consumer bills [Nera Consulting]. This will make Net Zero more costly.

68. As is conceded in paragraph 5.6.3 of the Impact Assessment, it cannot be presumed that imposing penalty charges on existing Scottish green SDG that are intended to make future Scottish SDG uneconomic compared to English or overseas energy will

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[14] Ofgem Access SCR - Impact Assessments, p.38

[15] National Grid ESO - Future Energy Scenarios July 2020, p.15

[16] SSEN Transmission – Transmission Charges: An overview of charges for use of the GB transmission system
This SSEN Transmission paper on Transmission Charges highlights the views of generators that there is "year-on-year volatility" of TNUoS charges which makes it difficult for generators to accurately forecast charges "even a single year ahead". This means that generators must calculate not only a higher quantum of risk for a given level of volatility, but also a higher level of risk premium for the same given return to account for the higher volatility overall. The magnitude of this effect is calculated at 35% of the total increase in TNUoS due to the TCR over the next 5 years, of which 25% is due to higher volatility and 10% is due to the higher level overall.

not have the same impact on existing Scottish SDG. This will make Net Zero unnecessarily more costly. This is again something that has not been assessed properly by CEPA, as their modelling contains the flawed assumption that "the lower bound cannot fall below the 'existing' level of capacity defined in each region in the initial spot year".

69. In 5.6.2 and 5.6.3 of the Impact Assessment Ofgem sets out key risks:

> "Key risks
>
> 5.6.2. We think there are two key risks associated with our reforms, with the first being that assumptions underpinning the FES that achieve net zero do not materialise, undermining our benefits case. In particular, if there are not changes to planning permissions in England, then generation may not be able to move zones in response to TNUoS. Therefore, benefits associated with lower constraint costs or reduced transmission investment may not materialise.
>
> 5.6.3. The other key risk is that our modelling has not sufficiently identified the impact of our reforms on repowering decisions, due to the fact it is based on generic generation assumptions, rather than the impact on different renewables located around GB. We think 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."[17]

70. These are less risks, as certainties. The English planning system has not changed to facilitate the necessary generation required by Net Zero to move from Scotland to England, and neither the UK nor the Scottish Government are pursuing a strategy that involves such plans. Indeed, they are predicated on Scotland being a key area for green energy investment. For Ofgem to unilaterally undermine the aims of both the UK and Scottish governments in that way contributes only negatively to the investability of the UK and to Net Zero means that Ofgem starts to overstep its role as a regulator by sending signals to influence new policy rather than aligning with existing policy. That newly-uneconomic sites cannot be repowered is also a certainty, and independent generators in IREGG and others have made that point in meetings with Ofgem previously. It is positive that the impact assessment at least acknowledges this as a risk, but underlines the fact that Ofgem's approach to TNUoS is currently detrimental to Net Zero.

71. Ofgem's presumption, set out in par 5.4.2 concedes substantive risks to Net Zero and to the ambitions of the Prime Minister and the Scottish government to grow the scale and rate of green energy in Scotland:

> "5.4.2. Our reforms should lead to changes in the generation mix, with an increase in larger onshore and offshore wind in Scotland and solar and wind

[17] Ofgem Access SCR - Impact Assessments, pp.49-50

projects in southern zones. However, our modelling does not capture any potential impact of changes to the generation mix and whether it has any implications on Security of Supply, though we would expect any such impact to be limited."[18]

72. The presumption that by boosting locational discrimination against Scottish green generation that it will lead to an increase in Scottish green generation that is larger is both without evidence and rests on the defective premise that such factors as the planning system are immaterial to the construction of infrastructure. It also neglects to recognise the impact of the boost given under TCR to Ofgem's penalty locational charges on Scottish transmission connected generation which makes it less investable compared to an equivalent project on the continent that exports to England via an EU interconnector on which such penalty charges are not levied: a clear distortion of the market to the detriment of Scotland's energy ambitions.

73. Generators and investors are constrained by the planning system and other factors which Ofgem has not modelled and which it has not considered. Ofgem's presumption that imposing penalty charges on SDG in Scotland will lead to "an increase in […] solar and wind projects in southern zones [of England/Wales]" is reflected in the modelling, while keeping all capacity mixes constant. This is not realistic. In contrast Ofgem's 'principles'-based assumptions are that it will lead to increased solar with no additional effects being modelled, while larger more efficient wind farms are presumed. This is also not to be expected as any move south in generation will be hampered by planning restrictions in England. Tighter rules would mean wind farms would not be able to deploy the latest large turbine technology, thus increasing LCOE. Viable locational signals need to have regard to the context being navigated.

74. At various points in the Access SCR consultation, Ofgem refers to itself as taking a "principles-based" approach. Ofgem also conceded that "that there is increasing evidence for a wider review of TNUoS charges".[19] Such a review needs to consider the extent to which TNUoS is fit for purpose. And given the extended length of time such a review will take, if the rate and scale of green energy deployment needed for Net Zero is not to be undermined and made more costly, it is imperative that:

    - penalty TNUoS charges are not imposed on SDG in the interim – were that to happen it would risk the operation and repowering of existing Scottish green energy;
    - the impact of the Scottish locational penalty TNUoS charges that Ofgem has boosted under TCR are effectively addressed.

75. As stated above, the review needs to take on board the flaws in the principles upon which the operation of TNUoS is based. If the desire is to charge generation for the cost implications of longer network connections, then the energy transport costs (carrying power from A to B) are addressed separately by Transmission Loss Factor.

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[18] Ofgem Access SCR - Impact Assessments, p.43
[19] Ofgem Access SCR - Consultation on Minded to Positions p42; p72.

Given that TNUoS (on generators) is intended as a proxy for the cost of future grid build, and not that of current grid, the use of TNUoS as such a proxy is flawed in principle: if the principle of TNUoS is to send a locational signal to which generation can locationally react, then it is not clear how in principle can it be applied as a volatile charge to existing generation which, by definition, cannot relocate in response to an evolving locational signal? TNUoS is not sending signals to which generators can meaningfully react – once a generation asset is built it cannot move, and the unpredictability of future TNUoS makes it very hard to calculate future locational penalties when choosing sites.

76. Ofgem has stated in its Access SCR Minded to Consultation document (par 1.13):

> "A key driver of our reforms is to make network charges more reflective of the costs that users confer on the network. We expect that more cost reflective signals could drive a range of beneficial behaviours to help reduce network costs and encourage the optimal generation mix to come forward, as well as ensuring that those driving new network costs are not cross-subsidised by other users."[20]

77. But that is not what Ofgem's changes propose given that their impact would result in a Scottish wind farm that has been operating for twenty years being penalised with new locational penalty charges: it is no more driving new network costs than any other existing green generation. The generation that is driving new network costs is the carbon-emitting generation which by virtue of the carbon it emits requires new additional measures to be taken to offset or replace it. The need for new green generation to be located in Scotland reflects the requirements of meeting Net Zero at least cost. If 'signals' like TNUoS are not realigned with Net Zero, distortions are created, just as an airframe of a twin-engine aeroplane would be distorted if the pilot put one engine into forward thrust and the other into reverse.

78. In fact, the real situation that needs addressing is the complete opposite of Ofgem's assertion: the current TNUoS methodology overestimates the costs of grid reinforcement in Scotland and therefore imposes much higher charges on Scottish generators than are actually justified as a 'signal', with a large proportion of these punitive payments being transferred to (predominantly high carbon) generators in the south of England, who are credited for using the network. As generation cannot actually have a negative cost of using the system, (even those in locations Ofgem deems as beneficial), these TNUoS credits constitute a cross-subsidisation of southern generators by those in the north.

79. Furthermore, as research by SSEN has recently shown, these TNUoS credits can be a key component of the business cases of some thermal plants, particularly those that only run in peak scenarios:

> "Some conventional generators rely on the locational signals of TNUoS. Generating units that are rarely dispatched, however can be called upon at

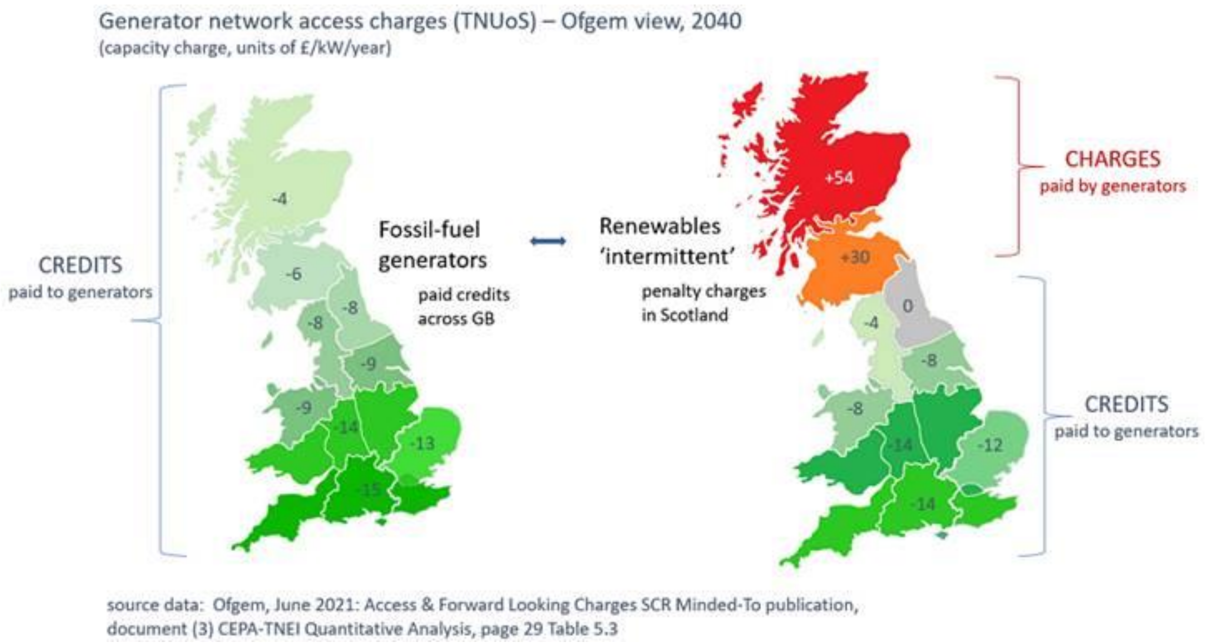
[20] Ofgem Access SCR - Consultation on Minded to Positions

any time, rely on the credits received from TNUoS alongside other mechanisms to sustain their plants."[21]

80. This testimonial from a conventional generator clearly shows how TNUoS credits are being used to keep thermal plants operational. According to Ofgem's own principles, this represents a market distortion, as it means that generators do not have to cover their costs in the wholesale markets and CM, thus preventing the true value of peak capacity from being properly priced in the market.

81. We therefore suggest that any future 'principles-based' approach to reforming TNUoS to address the clear distortions that TNUoS credits create in the market

82. Using the CEPA Analysis table 5.3 this image visualises the generator network access charges (TNUoS) if the minded-to decision were to be implemented:



83. In principle, the need to adapt generation location and energy networks is driven by Net Zero, not the location of pre-existing generation. The principle is clear for using Transmission Loss Factor to ensure that the higher costs are reflected of carrying power over longer grid connections. Penalty TNUoS aims to estimate the cost of additional carrying capacity but is not doing so correctly. It exaggerates the cost, ignores the planning system and resources, alongside geographic diversity benefits to both price volatility and to mitigating balancing/flexibility costs. Charging existing Scottish power generation extra penalty TNUoS over and above the charges levied on English generation for future grid upgrades whose benefit will be for overall UK Net Zero highlights that the old principle is no longer fit for purpose. Such an approach is a distortion of the principle of cost reflectivity, and a

[21] SSEN - Transmission Charging Stakeholder Feedback Report 2021, p.5

review of TNUoS needs to start from that principle. The energy transition will require a significant shift in generation type, locations, demand responsiveness, and power flow characteristics, to be fit for the future.

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