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Dear Sir or Madam

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

Thank you for the opportunity to respond to the Consultation on your minded to decision for the first part of the Access and Forward-looking Charges SCR. Please find below E.ON's response.

Summary

We are pleased to see Ofgem pushing forward with the Access and Forward-Looking Charges SCR as much as possible. Delays to this SCR are having significant impacts on distributed generation project funnels, especially given the impact of the Targeted Charging Review to this part of the industry.

With regard to connection boundaries, E.ON is very pleased to see proposals to make the demand connection boundary shallow. With the need to decarbonise transport and heat over the next few decades, it is vital that network constraints are not the bottleneck that prevents the UK from hitting its carbon budgets and ultimately Net Zero by 2050. The ability to relocate low carbon technology (LCT) such as EV charge points and heat pumps to areas of the network not congested is very limited for business and impossible for domestic customers (though we appreciate that this only impacts domestic customers who are wanting to exceed the 100A limit to most homes[1]). Socialisation of the cost of network reinforcement should also dramatically improve the ability of DNOs to run local flexibility markets which will be far more competitive (and hence cheaper) than traditional reinforcement.

The connection boundary for generation connections should also be shallow. Whilst generation has potentially a little more scope to relocate, there are still many more important factors that dictate a business case (such as wind yield and availability of

[1] Most homes with a single 7kW EV chargepoint and an 8kW heat pump will still come under 100A, but a rapid EV chargepoint or a larger heat pump are liable to tip the house connection over the limit

land). Allowing generation to connect via a shallow connection boundary ensures that DNOs can fully investigate flexibility markets and ensure competitive, transparent and fair connection charges rather than the totally untransparent value of a flexible connection. A shallow connection boundary ensures no 'free riding' of assets that connect just before reinforcement is required. It also allows the DNO to take a long-term view of reinforcement and include additional growth in both demand and behind the meter generation in its plans.

For access rights, E.ON believes that better defined non-firm access still suffers from the problem of developers not being able to value the flexibility that they are giving up and allows the DNO to set its own terms rather than allowing a market based price discovery for flexibility. Instead we advocate the application of firm access for all new connections with a requirement to participate in local flexibility markets if required (mirroring what happens at transmission). We acknowledge the need to develop distribution equivalent standards for planning and security but believe that the timeframe of implementation by April 2023 is probably already not deliverable and that DNOs will have to develop final business plans against minded to decisions at best. Therefore, we believe it is more important to future proof these changes than to rush them through to align with the RIIO ED2 process. We are happy with the minded to decisions around time profiled access rights and not taking shared access rights forward.

Distributed generation is having an impact on the transmission network and even if it isn't happening today, then it will happen in the near future. Because of this, we are broadly in agreement with Small Distribution Generation (SDG) having to pay TNUoS. However, we feel the threshold of 1MW is slightly too low as it will impact the highest level of FiT generators (the FiT scheme included generators up to 5MW). Requiring solar farms to pay TNUoS could threaten the business case of many sites that have many more working years left. When the UK is trying to deliver on Net Zero, it does not make sense to make the business case for low carbon generation even more difficult than it currently is. We believe that there is an argument that low carbon SDG below 5MW should either be exempt from these proposals or should be given a longer transitional period due to the requirement for large amounts of renewables needed to deliver Net Zero. Six figure increases in costs will be difficult for many low carbon assets to absorb and there is the real threat that these additional costs could lead to necessary assets like this closing just when the UK needs them most.

We also believe that there is a case to be made for SDG >5MW being exempt from TNUoS charges where the asset exports very little power onto the network, primarily as it is servicing an onsite customer. Export agreements are maintained for these types of site for instances where the onsite customer does not need power (maintenance periods) and the SDG's only option is to export onto the network. It would seem disproportionate to charge these types of SDG the same level of TNUoS as SDGs who are dedicated to exporting onto the network.

In summary, we believe that all connection boundaries should be made shallow, that non-firm access rights should not be taken forward, but rather replaced by firm access with a requirement to participate in local flexibility markets and that SDG should pay TNUoS with the exception of low carbon generation <5MW that is essential to delivering Net Zero.

Questions:

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 fully support Ofgem's decision to remove the connectee contribution to reinforcement for new demand connections. With LV networks becoming more and more congested and constrained, we believe that the DNOs are best placed to manage this risk and are more invested in finding cost effective solutions (such as non-network options via open and transparent flexibility markets). Having some of the significant reinforcement cost fall upon the next new connectee is likely to delay low carbon technology (LCT) uptake (such as EV chargepoints and heat pumps) as well as supporting 'free riding' of connections that are connected just before reinforcement is required (despite the fact that these connections are also contributing to the constraint/congestion just as much as the connectee who tips the balance).

Under the existing system, connectees could find themselves liable for very large reinforcement costs that make their project business cases untenable (we have evidence of property developers being quoted up to £8m to connect 800 homes with PV in Scotland). This is likely to mean that projects will stall or be shelved. We appreciate that the current system gives a locational price signal (connect where there is spare capacity and not where the network is congested), but we feel that this signal can be counter to the overall aims of the connection. For example, if a bus company is looking to install rapid EV charging points to fuel its fleet, it will not make sense for the charging points to be a long way from the depot where the buses are stored. Similarly, property developers will want to build new homes in areas where people want to live which may not coincide with uncongested parts of the network. For this reason, we believe that reinforcement costs should not delay or prevent the building of such new LCT infrastructure.

We believe that it is also fairer and more equitable to share the cost of infrastructure upgrades amongst all the beneficiaries i.e. the entire community. A similar methodology is used for new roads, charging all taxpayers regardless of whether they use the new road as there is a societal benefit overall. The same societal benefit is true for network reinforcement. It also brings reinforcement triggered by a single new connection into line with reinforcement that is required due to gradual demand increase where no one party is the identifiable cause of the necessary reinforcement.

Also, by allowing all reinforcement costs to be socialised through DUoS charges means that DNOs will be better able to run local flexibility markets to tackle demand congestion. Under the current methodology, the new connectee is liable for a proportion of any activity undertaken to relieve the constraint. But the uncertain cost of flexibility being used as the solution (even if the cost is likely to be lower) means that most connectees prefer the certainty of traditional reinforcement. And without the ability to fund all the flexibility costs through the DUoS charge, DNOs have been unable to run as many flexibility tenders as they would have liked. With this minded to decision, DNOs should be better able to consider all solutions and pick the most cost effective.

We would have liked to have seen a similar approach to the socialisation of network reinforcement for the generation side as well. Whilst we agree that new generating assets can react more favourably to moving to a new location (and so are better able to respond to locational signals in the connection charge), there are still other considerations that will be more important to a developer e.g. wind yield, available land etc. However, we believe that locational signals are best suited to ongoing forward-looking charges (which are paid by everyone responsible for constraints and not allow for 'free riding' for previously connected assets). As such we look forward to the second part of this SCR minded to decision which will cover DUoS charge reform and the potential for more granular locational signals.

We acknowledge that the quantitative modelling around the costs and benefits of a shallow connection boundary suggests that going to a shallow model for both demand and generation would be £720m-£1170m[2] more expensive than the hybrid model, but this is on the basis of the status quo for DUoS charging. As we know that the second part of the SCR minded to decision (expected later this year) is going to look to address locational price signals within DUoS, it will not take a huge change to mitigate this additional cost. Therefore, we would like Ofgem to keep the shallow option for generation open until the work on the second part of the SCR has been finalised. Making a decision based on analysis that is known to be incomplete would seem illogical. And as stated previously (and acknowledged in the minded to decision), there are other benefits that have not been captured by the impact assessment which could drive down costs such as more incentives for local flexibility markets.

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 connection charging arrangements send very strong signals to connectees where reinforcement across multiple voltage levels is needed. However, these signals simply act to kill the project rather than to relocate it. We are working with a property developer in Scotland on a housing scheme with PV on the roofs. Due to export constraints, the property developer was initially quoted up to £8m for reinforcement work which would have made the project uneconomic. The alternative for the property developer was to 'ground' all PV generated export from each house, thereby removing the homeowner's ability to receive the Supplier

[2] Based on Table 3 of the Impact Assessment

Export Guarantee (SEG) as well as significantly reducing societal benefit from having PV on the roofs. We have installed a system that allows each home to export all of its PV generation and maximise collective self-consumption across the entire housing estate and only pulling back export (incrementally rather than a binary on/off) from each home when this would lead to net export exceeding the capacity permitted by the DNO due to physical limitations from the LV substation.

The impact of the proposed changes means that the property developer no longer has to worry about an issue that they are not best suited to tackle and rather places the risk with the DNO who can assess all potential solutions (including a system like the one E.ON are installing) in order to minimise the cost to all customers in the area. The property developer will not be forced to consider solutions that lead to unintended consequences such as the dumping of renewable energy when we are all trying to deliver our Net Zero commitments. And with the new charging arrangements suggested by the minded to decision, property developers are still incentivised to consider where best to locate and to work with the DNO and flexibility providers such as E.ON in order to get their connection built as speedily, economically and efficiently as possible.

For example, a property developer may want to build a new development on a congested part of the grid and after the implementation of the shallow connection boundary it might seem that without the locational signal of the old connection charge there is nothing to stop them overloading the network even further. But the DNO can decide when to work on the reinforcement of the grid, offering the property developer a quicker connection if they work with a flexibility provider (like E.ON) to include a system within their properties that allow the DNO to control the overall export/import. The decision on which flexibility provider to use can be put out to tender (thereby ensuring a competitive process).

Whilst this is an extreme example, we believe that similar issues are being faced by not only property developers, but also embedded generation developers. Small distributed generator (SDG) developers are currently forced to make a decision between waiting several years and paying large reinforcement costs or accepting a flexible connection from the DNO (via an Active Network Management (ANM) platform). At this point, the SDG developer has no idea as to the value of the flexibility that they are giving over to the DNO and therefore no clear way to ascertain the cost benefit of this flexible connection. By making the connection boundary shallow for generation as well as demand, the SDG developer can connect and later bid into flexibility markets that the DNO will look to run in order to tackle the constraint. Separating the connection charge and the potential revenue from flexibility allows the DNO to create a fair and transparent flexibility competition which is likely to lead to lower costs overall for all customers.

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?

Under the current arrangements, DNOs are not incentivised to think particularly long term in their reinforcement. Whilst demand led reinforcement (gradual increase in demand) is funded by DUoS charges, reinforcement due to new demand connections (an ideal opportunity to also capture any mid-term gradual demand increase) is not encouraged as the new connectee is paying for a share of the upgrade and therefore the DNO is incentivised to only consider the reinforcement due to the new demand connection. This can lead to very small incremental improvements in the network and would, over the long term, lead to the cost of reinforcement being much higher than it needs to be. By socialising the entire cost of reinforcement for demand connections means that DNOs can take a long-term view of the reinforcement solution that they recommend and/or apply. It is important that DNOs consider a long term solution as short term flexibility can defer very expensive reinforcement until it is more certain that a higher level of upgrade is required due to gradual demand growth on top of a new connection demand increase. Without this long-term view, flexibility could be seen as an expensive choice.

Whilst the above refers to demand connections and gradual demand growth, the same can be true for generation. More and more homes and businesses will install behind the meter (BTM) generation and energy efficiency measures that the DNO will not be aware of. For a generation dominant area, reductions in demand through these sources act in a similar way to gradual demand increase for a demand dominant area and therefore all the arguments above hold true for generation dominant areas too.

For example, a solar farm developer may wish to connect to a generation dominant area and therefore force the DNO to act to support the network. Through a shallow connection boundary, the DNO will be able to take into account the slow rise of BTM generation in the area that is happening as well and then plan a larger, more cost-effective reinforcement project. In the meantime, the DNO can fund a flexibility tender through an increase in DUoS charges. Without the change to the current arrangements, the DNO would not be able to fund the flexibility tender (as the solar farm developer is unlikely to want to be exposed to the uncertain cost) and therefore would have to design a reinforcement scheme (paid for by the solar farm developer) that only meets the requirements of the solar farm and doesn't include the gradual increase in demand reduction in the area from energy efficiency and BTM generation installations.

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?

As a SDG developer, whilst we have no direct experience of being offered a connection charge linked to a flexibility tender, we would be nervous to accept a connection with no certainty in the cost (even if that cost might be lower). Therefore, we agree with the hypothesis put forward in this question that the shallowish connection boundary is hampering other means of providing capacity, especially where the cost of providing that capacity would be unknown at the point of agreeing the connection offer.

Under the minded to proposals, we agree that DNOs will be able to make full use of the wide range of solutions (both network and non-network, including flexibility markets) by allowing the DNO to make the correct decision for the network and funding it through DUoS. Extending the full shallow connection boundary proposal to generation can only make those incentives stronger for the DNO to find the most cost effective solution available and therefore keep costs as low as possible whilst allowing SDG to connect and drive forward the delivery of Net Zero.

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 do not have any strong opinions on the retention of the High Cost Cap.

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 are of the view that the recovery of reinforcement costs associated with transmission triggered by distribution should be treated as any other reinforcement needed at a higher level than the asset connection that triggered it i.e. in the minded to decision, Ofgem are of the view that new connectees should only pay for the reinforcement required at the same level at which they are connecting. It makes no sense to treat the EHV - transmission boundary any differently to the LV – HV boundary for example. As stated in the decision document, this would also then distort the new connection market with large distributed generators facing either a large distribution <u>and</u> transmission reinforcement charge that would have to be paid upfront whilst transmission connected generators would only face a transmission charge that they could pay over many years.

We are not advocating credit being extended to large distribution generators, but to minimise the distortion in connections, large distribution generators should only pay for the reinforcement associated with the voltage level it is connecting at and the transmission reinforcement costs socialised through the TNUoS charge.

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

Given that the current system requires developers to pay higher connection charges upfront than the minded to proposal, it is unlikely that the new charges will push developer projects to cancellation. We appreciate that there may be other reasons for investments to be cancelled, but these are likely to have occurred regardless.

The only issue would appear to be whether lower connection charges without liabilities/securities are likely to encourage marginal business cases from going ahead (whereas before the high connection charges will kill the project before any DNO investment is made). This is a possibility, but we believe that introducing liabilities/securities just recreates the same problem again (and reintroduces locational charges which we believe are best suited to DUoS charges).

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?

Moving to a shallow connection boundary will mean that the DNO becomes the eligible person for reinforcement costs (with regard to ECCR payments) but given that DNOs will be refunded through DUoS charges, this means that there should be no need for ECCR payments. In our opinion, this is another good reason to move to a shallow connection boundary for generation as well as demand, doing away with the need for ECCRs for reinforcement work all together.

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?

Whilst we are supportive of innovative ways of encouraging renewables and LCTs to connect to the network, we do have reservations about the impact of non-firm access to flexibility markets. By 'buying' an asset's flexibility at the point of connection, DNOs are able to build up a 'land bank' of flexibility which will mean that a competitive and transparent flexibility market could struggle to form. Asset developers will have no reference point to understand whether they have received a fair price for the flexibility that they have relinquished. Even if Ofgem regulate this area of DNO activity (by standardising non-firm access right charges), this will not allow for transparent dynamic market prices.

We believe the best way to allow LCTs and demand to connect whilst ensuring networks are protected is to imitate the solution used for transmission in that all connections are made firm, but anyone connecting to the network will be required to participate in local flexibility markets should they be required. This ensures that commercial markets are given the priority they need to be as competitive as possible i.e. maximum liquidity to drive down prices.

We appreciate the concerns that Ofgem have around the lack of time to develop the necessary planning and security standards that are already present in transmission but believe that this is taking a short-term view of the new arrangements. We understand the desire to get Access SCR changes agreed so that DNOs can factor them into their ED2 Business Plans. However, given that the larger (and more influential) area of DUoS charge reform is not anticipated to report its minded to decision until after the draft ED2 business plans are submitted, we believe that this rationale has already failed. Therefore, we would suggest it is better to future proof access options now, rather than ruling them out because they do not meet an arbitrary timeline that is already under stress.

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

We are highly supportive of time-profiled access option included in the minded to decision due to the clarity that it can give both to DNOs and developers as to the impact of new connections and the impact on a project business case. Time-profiled connections should also ensure that networks are utilised as efficiently as possible, encouraging new connections to trade-off some revenue for lower connection charges (as possibly ongoing lower DUoS charges). Unlike non-firm connections, developers can have certainty as to what they are giving up and the value of that trade-off. Similarly, DNOs will have certainty as to the impact of the new connection on the network at certain times of the day.

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

We are in agreement with Ofgem that whilst shared access in theory looks an attractive proposition, in practise it will lead to highly complex commercial relationships between connectees. We believe that the only method that would work for the DNO would be to have a single point of contact for the collective of assets that are sharing a connection. This single point of contact would be responsible for all costs and charges as well as being liable for the total capacity exported/imported onto the network. We cannot imagine any company willing to take on this level of responsibility and risk as no one company will be able to manage or mitigate this risk. A better solution that is currently being pursued by the ENA is the trading of access which reduces the level of complexity to a well understood bilateral agreement where each party is clear as to their responsibilities and risks and can contractually manage breaches in a simple manner.

Question 4d: Do you have any comment on our proposed choice about how to reflect access rights in charges (i.e. connection and/or distribution use of system charges)?

We do not have any strong views as to whether access rights should be charged via connection agreements or via DUoS.

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?

We are not convinced that there are any issues around transmission access choice.

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

Standardisation of access rights across the DNOs would help to make industry processes more efficient in that developers will only have one set of contracts/processes etc to understand and discuss. At the moment a developer who is trying to compare and contrast different projects across the UK has to understand all the differences being offered by each of the DNOs in their connection process. Therefore, having a standardised process and methodology for calculating connection charges for different types of access such that a developer can make an informed decision would be preferrable to the situation we have today. We appreciate that each connection will be different, but we believe that there are enough commonalities in the networks that a 'indicative' model can be made available to developers so that they can get an early indication of the costs involved in the various options.

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

As stated in Question 4a, we believe it is more important to ensure that any changes to access, connections and forward looking charges are future proofed as much as possible rather than chasing an arbitrary date of 1 April 2023 in order to align with the RIIO ED2 process. It is our view that this date is already likely to be a challenge given that Ofgem's final decision is unlikely to be in 2021, leaving one year to make changes via the code modification process as well as any system implementation changes. With the TCR implementation dates slipping (TNUoS residual charge now expected April 2024) we believe that any benefit that might have been realised by being aligned with the RIIO process has probably already been lost. Therefore, we believe an implementation date of April 2024 is more pragmatic and sensible.

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?

We do not have any evidence of SDG contributing (or not contributing) to flows in the same way as large generation.

Question 5b: Do you agree with our threshold for applying TNUoS generation charges of 1MW? If not, what would be a better threshold and why?

Whilst we do not have any evidence that SDG does contribute to transmission flows, we believe that this is a very real possibility, if not now, then in the near future. With NGESO Future Energy Scenarios suggesting a doubling to trebling of decentralised generation between now and 2050, it is important to ensure that all generation is competing on a level playing field (but still in the context of Net Zero).

With the current boundary set at 100MW, we believe that there is a strong argument to reduce this level. The setting of a new threshold is somewhat arbitrary, but we believe that the proposed 1MW level is slightly too low as it captures the higher end of FiT generators (the FiT scheme includes generators up to 5MW).

Therefore, it is our opinion that in order to not threaten the business cases of renewable generators with plenty of working life remaining (especially in parts of Northern England and Scotland where TNUoS rates are higher) that the cut-off point for TNUoS charges should be 5MW.

We agree that going much smaller than this level would be disproportionate to the problem and add a large administrative burden to the industry. Also, going to sub 5MW in scale will start to include businesses who have installed microgeneration in order to reduce their consumption from the grid, but whose primary objective is not energy related. By increasing charges to these types of customers, it is likely that businesses will be put off investing in renewable onsite generation. Finally, as noted in the minded to decision paper, DNOs already have good sight of generation on their networks down to 1MW in size (through the embedded capacity registers), but below this level, DNOs do not have any additional information. Therefore, it will take a significant amount of effort to identify all small-scale assets for the first time (and for potentially a much larger number of assets).

Whilst we agree with the overall proposal of introducing TNUoS charges to SDG >5MW, we also believe that there may be a case for certain exemptions which has not been factored into the impact assessment benefit. In the BEIS and Ofgem recently published Smart System and Flexibility Plan, modelling suggests that the UK will be in need of ~60GW of low carbon flexible generation by 2050, of which ~15GW will need to come from flexible demand or generation. As the Plan states, flexibility is vital to delivering Net Zero at a minimum cost by maximising the consumption of intermittent renewables and thereby reducing the need for building new peaking plant. Savings from high levels of flexibility are estimated to be ~£10b p.a. by 2050. Therefore, any changes in network charges that put existing low carbon plant that could offer flexibility at risk also threatens delivery of the Smart System and Flexibility Plan. We believe that low carbon dispatchable plant (such as biomass or wind co-located with storage) should be given a longer transitional period in which to adapt. We suggest a transition period similar to the length of any subsidy scheme such as the RO or CfDs.

As an example, E.ON's biomass asset, Steven's Croft, is 44MW and sits in generation zone 12 which would mean Steven's Croft moved from having £0/kWh from the embedded export tariff to paying TNUoS (which is currently charged at ~£15.5/kW). This means that Steven's Croft will see its costs increase by ~£700k p.a.. Steven's Croft currently runs baseload operation so there is very limited scope for it to do additional running and the only BM actions that it could tender would be to bid to turn down. As it receives ROCs for its generation, BM turn down prices would need to be very high to make this a commercially rational decision. Therefore, additional revenue from the BM is likely to be very small. Finally, as with the BM, Steven's Croft will only be able to offer generation reduction to ancillary markets which would need to be priced higher than the ROC income and we suspect is fairly limited. Therefore, we believe that the scope for Steven's Croft to mitigate the significant increase in costs from TNUoS charges is very limited, despite it being a dispatchable low carbon generator that could potentially offer low carbon flexibility after its RO contract expires, exactly what the Smart System and Flexibility Plan is trying to encourage.

We also believe that a case can be made for the exemption of SDG > 5MWe paying TNUoS where the level of export is low. This can occur for many embedded generation assets that are built to provide power for a large onsite customer (onsite generation) who will typically consume a large proportion of the generation, but where an export agreement is maintained for the full capacity of the SDG to allow the asset to export all of its power to the network for those rare periods where the customer does not need it e.g. maintenance periods or to allow for "spill" generation to contribute to local demand on the network. It seems disproportionate to charge, for example, a 10MW generator that usually exports <1MW (as >9MW of generation are consumed onsite by an industrial process) but which has a 10MW export agreement to allow it to continue generating when the industrial process is on maintenance the same level of TNUoS as a 10MW wind farm that is dedicated to exporting to the network. We would advocate the use of the already established process under TCR whereby assets can apply for an exemption from TNUoS residual charges or, where more appropriate, a reduced level of TNUoS residual charge in order to fairly reflect each site's unique configuration. Since this has already been successfully implemented under TCR, applying a similar process under SCR should represent little additional administration for both DNOs and SDGs yet it will allow charges to be proportionate according to the site in question. We would be happy to discuss instances where we think this is applicable with Ofgem at a bilateral meeting.

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

We do not have any evidence that distribution connected generation at a GSP has a different impact to 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?

We do not have a preference for addressing the local charging distortion.

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

We are highly supportive of Ofgem considering transitional arrangements for SDG being charged TNUoS. Although the option of charging SDG TNUoS has been considered for quite some time, we believe that existing SDG has not really been able to mitigate this risk sufficiently in the interim. Whilst we acknowledge the widening of access to new markets (such as the BM), this is still in its infancy. For some assets (primarily in Scotland), the increase in charges (from £0 to a maximum of £40/kW which for a 99MW unit amounts to a bill of ~£4m pa) will be difficult to meet overnight. Therefore, we believe that Ofgem should look to give existing dispatchable low carbon assets a longer transitional period than inflexible or high carbon plant. Existing low carbon generators could (and in some cases already do) contribute to the 15GW of flexibility that the Smart System and Flexibility Plan estimate the UK will need to hit Net Zero at least cost.

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

We believe that TNUoS charges for SDG should be administered in as similar fashion to embedded export tariffs (EET) charges/revenues as possible to minimise system and governance changes. The ESO should be able to easily identify impacted SDG through the embedded capacity register and agree connection agreements for access to the transmission network (TEC). Then charges can easily be passed through to suppliers who in turn can pass them onto the relevant SDG (Option 1). Aggregating up SDG into a zone and charging suppliers for the zone (Option 3) will only pass the need to split the charge onto suppliers who will be less well informed about TEC than the ESO. And as the ESO does not currently have a commercial relationship with SDG (Option 2) then going via the supplier would simplify the process. Option 4 (ESO charges the DNO and the DNO then charges the supplier for joint TNUoS and DUoS) seems to add far more complexity and risk to even more parties then Option 1. We therefore agree with Ofgem that Option 1 is the best option for administering TNUoS charges to SDG.

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

We believe that any changes to network charges needs to consider the requirement for significant amounts of flexibility at the forefront of its analysis as made clear by the Smart System and Flexibility Plan. It is clear that impact assessments are not considering this at present which will have a dramatic impact on BEIS/Ofgem flexibility plans. The Targeted Charging Review has already stalled or help cancel numerous projects that could have helped deliver this and there is no indication that the Access and Forward Looking Charges SCR is looking to mitigate this knock-on effect.

We are also very conscious that numerous sources of revenue for SDG (BSUoS embedded benefit, Triad avoidance, Embedded Export Tariffs) have either been removed, are to be removed or are minded to be removed. This has had a severely damaging impact on embedded generation commercials, especially where existing assets are unable to participate in new markets (like Dynamic Containment, Quick Reserve etc) due to new exacting requirements. Ofgem need to be minded about the dramatic impact this is having on a sector that is being forecasted to grow and support our necessary move to Net Zero.

Finally, we are concerned with the minded to decision regarding sub 1MW generators. By removing the £0/kW cap for EET, this will expose Scottish <1 MW generators to an EET charge. Under the current charging mechanism (charge based on metered export during Triads), Scottish generators could avoid the EET charges by turning off during the Triad periods, a completely perverse situation. Therefore we believe that Ofgem should look to retain the £0/kW cap and ensure that there is no perverse incentive for generators to stop exporting when they are needed the most.

General question

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