Access and Forward-looking Charges Significant Code Review: Consultation on minded to positions

Northern Powergrid's response

Key Points

We welcome the proposed review, and agree that changes are necessary, but there is scope to improve the minded to positions. Electricity distribution access rights and connection cost signals are currently working better than the consultation recognises and any changes should send efficient and effective forward-looking cost signals.

- Removing connection-driven reinforcement price signals may encourage the connection of more generation and storage, but more of the reinforcement costs would transfer from developers to be socialised across all customers.
- The proposed changes are potentially a step in the wrong direction as they create an inconsistent and complex two-tier system for demand and generation connections unless complementary changes are made to distribution use of system (DUoS) charges. Ofgem is as yet silent on any such changes.
- Connectees prefer a high degree of certainty when making business decisions. Whilst connection costs will be lower based on the proposals, the uncertainty associated with flexibility procurement and potentially more locationally volatile DUoS tariff will still remain a factor in their investment decision.
- We believe the time is right to reset the arrangements for independent distribution network operators (IDNOs) reserving capacity for larger speculative developments. Excessive capacity reservation and hoarding runs counter to the aims of the Significant Code Review (Access SCR), i.e. creating inefficient network use. This could result in inefficient network reinforcement costs being funded by the wider customer base.
- The interaction between the minded to position and the electricity connection charge regulations (ECCR) is complex and must be resolved properly if they are to be implemented successfully.
- We remain supportive of alternative access choices to support efficient utilisation of networks, but the lack of DUoS reforms, as an alternative, may be largely unattractive to existing customers.
- While a wider range of options for time-profiled access are possible, the risks from non-compliance are likely to increase with connection size. Physical control equipment will be necessary, to manage risks of these customers exceeding the agreed access profile.
- We agree with Ofgem's position on transmission network use of system (TNUoS) charging arrangements for small distributed generation (SDG): that the DNO-led model appears to be unnecessarily complex and onerous. We also agree that Ofgem should carry out a wider review of TNUoS arrangements, given the uncertainty surrounding and impact of, its minded to positions.
- The proposals are virtually silent on the DUoS elements of the reforms and we assume that Ofgem will not be taking forward any such proposals in 2021. Clarity on future timelines is required.
- The risk is that the distribution network operators' (DNOs) RIIO-ED2 business plans will be based on a significant level of uncertainty and assumption which may, or may not, result in DUoS customers paying too much. We are aware that Ofgem is considering an uncertainty mechanism to take account of any changes; we will work with Ofgem to develop any such mechanism.
- We are supportive of Ofgem's plan for engagement through RIIO-ED2 working groups to develop common approaches to help manage the uncertainty surrounding the impact of its Access SCR decision on user behaviour and note that this needs to happen quickly.

Contents

1. Introduction and general observations

1. We welcome the opportunity to respond to Ofgem's minded to positions on the Access and Forward-looking charges Significant Code Review ('the Access SCR') and are supportive of the work being undertaken to ensure that appropriate network access and connection charging arrangements are in place. We are concerned that DUoS reforms are currently outside the scope of the minded to proposals.

2. Any changes to the current arrangements should send efficient and effective cost signals to network users as we transition to a smarter, more flexible energy system. Given that smart technologies and new, innovative business models, offer opportunities to adjust demand and generation at times and places where network capacity is limited, we believe that it is increasingly important that network capacity is allocated and used in a way which reduces the potential overall costs to new and existing consumers. We recognise that work is being undertaken as part of Ofgem's Full Chain Flexibility (FCF) review and the resulting uncertainty given its impact on areas on which Ofgem is not consulting.[1]

3. We agree with Ofgem that the proposed reforms have close links with the RIIO-ED2 price control period, which will be unlike any previous regulatory period. We recognise that DNOs will play a major role in meeting the UK's target of reducing carbon emissions by almost 80 per cent by 2035, and like the other DNOs; our network will require significant investment to facilitate this change.

4. To optimise our investment to 2050 we are taking a flexibility-first[2] approach to our investment strategy for decarbonisation which entails prioritising flexibility solutions where we can and only implementing network solutions where flexibility is not viable. However, that investment would almost certainly have to increase further based on Ofgem's minded to proposals given that connecting customers would contribute less to wider network costs. It will also be challenging to accurately quantify the potential scale of this additional investment in the short term due to uncertainty around how customer behaviour will change, particularly if the connection boundary is moved to shallower arrangement (i.e. less financial burden in placed on the connecting customer with more of the costs being met by the DNO and, ultimately, by all existing customers). We would highlight that the effect on investment by different DNOs will depend on the mix of new connections for demand and generation. For demand-rich areas, there may need to be comparatively more investment due to the proposed 'shallow' connection boundary.

5. It has never been more important that network charges send the 'right' forward-looking cost signal to network users in order to influence both where demand and generation is located, and how it is then used. To achieve this, there will have to be necessary trade-offs between Ofgem's guiding principles that underpin the Access SCR reforms[3], as well as between the areas covered within those reforms. Unfortunately, through both its minded to proposals and engagement in developing the reforms, Ofgem may have confused stakeholders by creating uncertainty about the future of DUoS charges. Without

[1] Full Chain Flexibility is one of the strategic change programmes identified in Ofgem's Forward Work Programme 2021-22: https://www.ofgem.gov.uk/publications/forward-work-programme-202122

[2] Page 44 of our RIIO-ED2 Plan provides further details.

[3] That: (i) arrangements support efficient use and development of network capacity; (ii) arrangements reflect the needs of consumers as appropriate for an essential service; and (iii) any changes are practical and proportionate.

certainty about the future position on how price signals will influence users of our network once connected, there is a significant risk that Ofgem's 'low-regret' areas of reform could have significant consequences for stakeholders who may, for example, either make uncertain investment decisions or postpone until a clearer picture is available. In the absence of this clarity on the whole package of reforms, it is difficult to assess the outcome of Ofgem's overall reform of network access and forward-looking charges as stakeholders have only been provided with part of the picture.

A holistic review of all charging arrangements is required

6. Cost-reflective charging is a complex policy area which needs careful consideration in the context of avoiding undue cross-subsidy, reducing opportunities for capacity hoarding, and other valid charging objectives such as the ability of users to respond to signals and price stability/predictability.

7. Network charges serve two distinct primary purposes:

   - The first purpose, **cost-reflectivity**, is to give price signals to users of the network, so as to encourage overall efficient behaviour; and
   - The second purpose is **cost-recovery** (i.e. to ensure that network operators recover their efficiently incurred sunk investments). Ofgem's regulatory model allows customers to benefit from low financing costs because it allows networks to recover efficient past investments from customers over time.

8. New market models should be considered as well as traditional approaches but they must be predictable and fair. In addition, outcomes must be:

   - good for consumers as a whole;
   - be technology neutral; and
   - not benefit one sector at the expense of material downside to another – in particular, vulnerable customers need to be protected.

9. In order for all market participants, including end users, to fully understand the potential impacts of the proposals, they need to be able to understand the effects of all aspects of their charges (e.g. connection charges, access arrangements, ongoing DUoS charges and transmission charges). The absence of a decision in any one of these areas makes a full impact assessment impossible to determine.

10. The proposals as drafted are virtually silent on the DUoS elements of the reforms and we understand that Ofgem will not be taking forward any proposals in 2021. That said, more complex DUoS tariffs are unlikely to be the most appropriate solution in a smarter, more flexible future. In our view, introducing more complex cost-reflective DUoS tariffs in order to drive efficient behaviour is likely to have a number of significant challenges in terms of transparency and predictability. We also observe that even today's relatively straightforward network pricing signals (i.e. the variation in tariffs depending on the time of day or week based on the red/amber/green (RAG) identification) are not always passed through to end-users by suppliers. This further suggests that suppliers and customers may be unwilling or unable to respond to more complex network charging, where the competitive market may not fully translate these signals into retail pricing strategies.

11. That said, cost-reflective DUoS charges are not the only way to encourage efficient outcomes. Other instruments, such as clearly defined and standardised curtailed connection contracts or distribution system operation (DSO) flexibility contracts, which DNOs are implementing and developing further, may also help to deliver these outcomes, as each channel could be used to send signals in relation to operation or investment. A coherent design needs to be adopted to ensure relevant price signals are sent once and only once to avoid double counting (costs and/or benefits), which would lead to inefficient outcomes. For this reason, the approach to connection charging and access arrangements must be considered in parallel with DUoS charging arrangements and the role of DSO/flexibility services – the approaches for each cannot be considered separately. If they are, it risks giving rise to the potential for regrettable and unavoidable outcomes based on assumptions and outcomes set out in Ofgem's 'low-regret' proposals.

12. In order to do this successfully, a holistic approach is needed that considers all aspects of charging in order to send appropriate cost signals. However, it is now clear that Ofgem's preference is to bring in some parts of the Access SCR reform in advance of others. We believe that this needs to be done with caution as the arrangements are complex and interlinked.

Current connection boundary arrangements

13. Stakeholders need to be aware that the connection boundary is the extent to which connecting customers pay for their connection including an appropriate proportion of any reinforcement that is required, and that the balance of those reinforcement costs is recovered through DUoS charges. It is important for stakeholders to appreciate that costs recovered through DUoS charges are initially funded by network operators, but are ultimately funded by all connected customers. Ofgem's proposals transfer connection costs from the connectee to the general mass of DUoS customers without any clarity on the future of DUoS charges i.e. it is uncertain how the costs will be recovered and by whom.

Ofgem's potential new connection boundary options

14. Ofgem is only considering changes to the connection boundary that reduce the contribution to reinforcement within the upfront connection charge by considering shallower or shallow charging arrangements.

15. We believe that the benefits of the current connection boundary arrangements have not been properly recognised such that the status quo is still a viable option that Ofgem should not discount.

16. We believe the current connection charging arrangements send a locational cost signal that is working well, with connecting customers paying a fair share of the costs they impose on the network at the time they invest in their project, and at the time where the DNO has a direct relationship with the customer/developer.

17. If Ofgem does decide to deviate from the current arrangements, it should do so with caution and be cognisant of the unintended consequences that its proposed arrangements might bring in terms of inefficient development of the network and increases in costs for all customers. The full implications of the proposed changes may not be forecast with certainty while the forward looking charges component of the SCR remains unfulfilled.

Access arrangements

18. We remain supportive of alternative access choices to support efficient utilisation of networks, although we appreciate that, without DUoS reforms, any alternative access choice may be largely unattractive to existing customers. However, alternative access choices can make a valuable contribution to decarbonisation by facilitating quicker and more efficient connections to connect more generation and storage.

19. We believe that removing contributions to reinforcement through shallow, or shallower, connection boundary options have a detrimental impact on an incentive for non-firm or time-profiled access uptake. Whereas, it may still be quicker to implement the 'low regret' non-firm or time-profiled access right choices under the current connection boundary arrangements, especially if opting for time-profiled or non-firm helps connectees avoid a reinforcement charge. It also moves the reason for a non-firm connection away from getting connected and towards the customer getting paid for it through flexibility contracts. If the DNO can't find customers to provide the flexibility who will contract in the timeframes associated with a connection (and there is now no onus on the connectee) then it will simply increase connections reinforcement, and not drive more flexibility. This could be an issue in the near term while markets are illiquid and improve in the medium to long-term as more aggregated flexibility from smart use of low carbon technologies comes on line.

20. Non-firm access via local area active network management (ANM) schemes and other forms of flexible connection have already facilitated cheaper connections for generators and continue to be a useful option to provide quicker, cheaper and more efficient connections. We are aware that some stakeholders have mistakenly asserted that ANM schemes have been promoted as a way of DNOs obtaining 'free flexibility', whereas they have simply been made available as an alternative connection option, should the connecting customer consider it suitable for his purposes.[4] As ANM schemes are being developed to cover wider geographical areas, it is appropriate to keep the relevant arrangements under review, and work is taking place in that respect under the Energy Networks Association (ENA) Open Networks programme (under Workstream 1A, including products eight and nine).[5]

21. We note Ofgem's proposals on non-firm access include the potential to include compensation/flexibility procurement for new connections and we would highlight that existing customers connected via ANM schemes have already received financial benefit through reduced connection costs.

22. We would also highlight that in addition to the benefit to customers of providing better curtailment information and payments, there is also a need to consider the costs of monitoring and managing the required systems to deliver these services.

23. We agree with Ofgem that customer compliance with new access choices is necessary to deliver the benefits identified and that compliance with agreed access rights also reduces the risk of security of supply issues for wider users. We note that Ofgem expects that non-firm connections will require physical control equipment due to the nature of potential interruptions to network access. While a

[4] https://www.ofgem.gov.uk/publications/unlocking-capacity-electricity-networks-overview

[5] https://www.energynetworks.org/creating-tomorrows-networks/open-networks/

wider range of options for time-profiled access are possible, the risks from non-compliance are likely to increase with connection size. Physical control equipment will be necessary, especially on larger connections, to manage risks of customers exceeding the agreed access profile. This control equipment can be installed by the customer, and there is already a track record of customers benefitting from this.

24. Ofgem is right to be concerned that the current approach to exceedance capacity charges may not reflect the full costs incurred by DNOs trying to maintain security of supply for wider users. We note that Ofgem's DUoS charge design proposals (due to be published later this year) will outline a proposed approach to reforming capacity and exceedance capacity charges. We also note that this may include exposing users to the additional costs incurred by the DNO of non-compliance with access rights. We fully support a review of incentives to encourage users to stay within their agreed capacity levels so that the generality of customers are not adversely impacted.

Links to RIIO-ED2

25. Ofgem requires DNOs to submit RIIO-ED2 business plans detailing how they intend to meet the requirements set out in the sector specific methodology decision (SSMD). In the proposal Ofgem states:

> *"6.4. In the December 2020 RIIO-ED2 Sector Specific Methodology Decision (SSMD), we acknowledged that delaying publishing our minded-to proposals and decisions to ensure they are aligned with our FCF work means that DNOs would not have sight of our minded to positions in time to reflect them in their draft business plans. For this reason, paragraph 2.27 of our RIIO-ED2 SSMD said that we expect DNOs to base their draft business plans on the current arrangements, however, they should identify the parts that are impacted by our possible decisions on the Access SCR by reference to what they do know of what is in scope, what has been shortlisted, and the steers that have been given in the working groups."*
>
> *"6.5. We also expect the final business plans submitted later this year to take our proposals presented within this document into account. Through the RIIO-ED2 working groups we are keen to develop common approaches to help manage the uncertainty about the impact of our Access SCR decision on user behaviour (e.g. the extent to which our decision on the connection boundary impacts the volume or types of distribution connections during RIIO-ED2). This could require the development of additional RIIO-ED2 uncertainty mechanisms or the development of common assumptions across the different DNOs".*

We would welcome timely clarity on exactly how Ofgem would like us to include the impact of the Access SCR in our final business plan submissions (e.g. is it included in the base plan or is included as a sensitivity?).

26. In the absence of any clear direction on the future of charging arrangements, it is clear, based on the current status quo that our network is at the heart of the UK's decarbonisation journey, but that the extent of the impact on the network will remain unclear for some time. There are a considerable number of uncertainties in the pathway towards decarbonisation, for example:

- The extent of electrification of heat and transport versus other alternatives such as hydrogen – how electrical?
- The amount of locally distributed renewable generation connected to our network – how local?

- The speed at which renewables and LCTs will be adopted – how fast?
- The extent to which customer flexibility will be taken up – how flexible?

27. In the supporting impact assessment for its minded to proposals, Ofgem recognise *"hard-to-monetise impacts"* where Ofgem expects that the proposals will provide greater opportunities for DNOs to adopt a stronger whole system approach to network planning, including the most efficient means of facilitating new connections (e.g. through flexibility services). Whilst our draft RIIO-ED2 business plan demonstrates that we can do this effectively under the current arrangements, we agree with Ofgem that it is challenging for DNOs to quantify the impact of Ofgem's proposal ahead of submission of the final RIIO-ED2 business plans in December 2021. We are, therefore, supportive of Ofgem's plan for engagement through the RIIO-ED2 working groups to develop common approaches to help manage the uncertainty surrounding the impact of its Access SCR decision on user behaviour (e.g. the extent to which its decision on the connection boundary impacts the volume or types of distribution connections during RIIO-ED2) and note that this needs to happen quickly.

28. Ultimately, the risk is that the DNOs' RIIO-ED2 business plans will be based on a significant level of uncertainty and assumption, which may or may not result in customers paying too much. This could undermine the objective of the Access SCR to "*avoid unnecessary costs on energy bills in general*" and risk adversely impacting Ofgem's "protecting the interests of consumers in vulnerable situations" regulatory stance.

29. We, therefore, agree that Ofgem's proposals could require the development of additional RIIO-ED2 uncertainty mechanisms and/or the development of common assumptions across the different DNOs.

The timeline is confusing

30. In paragraph 1.22 of the main consultation document, Ofgem states:

> *"Under the SCR process, we are unable to provide a final decision on some parts of the SCR in advance of others, which means we will not issue our final decision6 and Impact Assessment for these reforms, until we are also ready to issue a decision regarding DUoS options."*

However, Ofgem has previously indicated that it will not be taking the DUoS elements of the SCR forward in 2021, which would imply that Ofgem will not make a decision until 2022 at the earliest. Ofgem has recently reiterated this position to the ENA.

31. In contrast paragraph 7.1 of the consultation states:

> *"We are planning towards the following milestones for concluding the SCR and implementing the outcomes:*
>
> - *Access SCR Minded to Consultation closes – 25 August 2021*
> - *Publish Final Access SCR decision – expected late 2021*
> - *Decision on relevant code modifications – expected in 2022*

[6] This would include a direction to industry to raise the necessary code modifications to take our decision forward

- *Reforms begin to take effect – from 1 April 2023"*

This suggests that the "Publish Final Access SCR decision", expected late 2021, will only relate to the areas of the Access SCR on which Ofgem is currently consulting, including distribution connection charging, definition and choice of access rights, and transmission charging for small distributed generation? That being the case, Ofgem would need to de-scope the Access SCR before being able to enact that decision.

32. We would have significant concerns, if Ofgem de-scopes the Access SCR by removing DUoS. However, we cannot envisage how Ofgem can deliver its proposed timeline unless this happens or Ofgem significantly reduces the scope of DUoS reforms (e.g. if Ofgem no longer considers more granular charges to be appropriate and/or if charges that reflect generation dominant areas are no longer desirable). It is clear that, as a minimum, DUoS reform will have to facilitate time-profiled access right choices, as we do not believe that the connection charge alone can fully reflect these choices (whereas it can on the firmness of access rights).

33. If Ofgem does intend to deliver DUoS reform in line with some of its previously shortlisted options, implementation in April 2023 is almost impossible even if the Authority agreed to derogation against the 15 months' notice period for changes to DUoS charges. We appreciate that Ofgem understands that April 2024 is more realistic, but even this target could be challenging without derogations and given the current uncertainty. We strongly urge Ofgem to clarify its intentions.

34. Additionally, the timeline to achieve implementation in 2023 is still extremely challenging for the 'low-regret' areas. Whilst Ofgem appears comfortable that its proposals can be implemented relatively easily (certainly connections boundary and access right choices), we are sceptical that this is viable given, for example our view that legislative changes are needed before amending the connection boundary. This concern is also supported by the experience of implementing Ofgem's targeted charging review (TCR), where some decisions caused major implementation problems. We firmly believe that it would be wrong to adhere strictly to the April 2023 implementation date at the expense of developing well thought out and robust decisions.

2. Responses to specific questions on Ofgem proposals for distribution connection charging

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.

35. Stakeholders need to be clear that reference to DNOs fully, or partly, funding reinforcement actually means that the general mass of DUoS customers (mainly demand customers) is ultimately bearing the cost. We continue to believe that the current distribution connection charging boundary is already sending an effective locational signal and that the proposed changes are a step in the wrong direction because:

- They create an inconsistent and complex two-tier system for demand and generation connection requests, primarily because the minded to decision doesn't provide clarity on the DUoS reforms.[7]
- They will require significant changes to legislation, regulation and industry codes within a challenging timescale.
- They favour larger connections by removing/reducing the locational signal and making commercial benefits to individual projects the key driver of the viability of the project, rather than supporting any wider network, or social, needs.
- Large demand connections that do not normally contribute to net zero, other than energy storage, will benefit from lower connection charges and potentially negatively impact decarbonisation.

36. We do not believe that Ofgem should consider making the connection boundary for generators 'shallower' than proposed (i.e. move to a 'shallow' boundary). Whilst we recognise the benefits of demand and generation having the same connection boundary, we consider it would be more appropriate to change the connection boundary for demand from 'shallow', as proposed, to 'shallower', if a consistent connection boundary between demand and generation was desired. This approach would retain more of a locational signal in the connection charge.

37. We are not opposed to policy makers subsidising generation connections but we would advocate the exploration of alternative ideas other than demand customers paying for new capacity while generation customers obtain cheaper connections with DUoS credits.

38. We believe that the high cost cap (HCC) should be retained as it is essential in order to maintain the risk mitigation of an unfair DUoS burden for those generation projects which drive unusually high reinforcement costs. We believe that it is appropriate for generation connectees to continue to pay towards reinforcement through the connection charge, and preferably maintain the current connection boundary, given generation arguably has more flexibility in where it locates. However, based on current

[7] It could be argued that there is a third tier as DNOs already fully fund reinforcement of shared use assets relating to existing (whole-current metered) premises rated at 100A or less subject to certain conditions. This 'third boundary' applies equally to both small demand and generation connections.

DUoS charging arrangements, generators would generally receive credits once connected, whereas demand will face charges.

39. We believe that the current connection boundary should remain unchanged unless Ofgem clarifies its intention on the scope for potential DUoS reforms. Particularly whether generators in generation dominant areas will be charged DUoS rather than receiving credits (i.e. where generation is driving the need for reinforcement).

40. If Ofgem does not change DUoS charging arrangements and if the connection boundary for generators moves to 'shallow', it would disproportionately penalise demand customers more than it currently does.

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?

41. The current connection charging boundary shares the cost of reinforcement between the connecting customer driving the requirement and the wider customer base who may benefit from any additional network capacity created. New connection customers will have varying degrees of locational flexibility compared with existing customers (i.e. large generation projects, such as solar or wind, are more likely to be in rural areas as opposed to a large demand project which needs better access to transport, supply chains, staff etc.). Customers' decisions on where to locate result from a robust commercial analysis which is influenced by a large range of factors, only one of which is the connection cost, as any project has to be economically viable.

42. We believe that the current connection boundary arrangements are a locational cost signal that is working well, with customers paying their fair share of the costs they impose on the network.

- Removing connection-driven reinforcement price signals may encourage the connection of more generation and storage but more of the reinforcement costs would then transfer from developers to being socialised across all demand customers within the same Distribution Services Area.
- It is not always the case that the general mass of DUoS customers benefit from funding socialised reinforcement to support specific connection projects. It is, therefore, unclear why it is appropriate that DUoS customers should carry more of the burden of reinforcement costs to make certain projects economically viable.
- Any change to the connection boundary to support the drive towards decarbonisation, needs to recognise where there are alternative options to reinforcement (e.g. support from flexibility). However, alternative options may only defer reinforcement in the short term and any steady underlying economic growth will eventually drive the need for further network reinforcement. Hence, it is important to ensure that an appropriate level of cost is borne by the commercial projects driving them when compared to the wider customer base that are able to derive benefit.

43. The proposed two-tier system (i.e. different boundaries for demand and generation) will have a number of effects.

It will create a perverse incentive to request more capacity than is needed or that may be catered for using alternative options. This goes against one of Ofgem's SCR objectives by supporting less

efficient utilisation of the network and contributes toward the need for future reinforcement as customers are under no obligation to release unused capacity.

- Not all locations will have other connecting customers that will benefit from connection driven network reinforcement.
- Customers who request more capacity than they need are under no obligation to release unused capacity to facilitate the efficient and effective development of the network. An appropriate mechanism for DNOs to reclaim capacity needs to be developed if upfront reinforcement costs are to be reduced or removed.
- Removing the reinforcement locational signal creates an additional perverse incentive for IDNOs to continue to request more capacity than is needed, especially for speculative developments. This is due to the fact, that under current arrangements, IDNOs do not face capacity charges at the boundary of the development so there is no cost signal in DUoS to influence efficient behaviour in requesting capacity. The proposed arrangements would compound this problem by removing the cost signal for any reinforcement.
- Where a housing developer seeks connection offers from a DNO and an IDNO, the DNO will seek to design an efficient scheme that minimises the total costs as DUoS customers fund the reinforcement. Conversely, the IDNO will seek to minimise the connection costs for the developer in the knowledge that the DUoS customers (the DNO) will fund any reinforcement costs.
- Even where IDNOs request excessive capacity in respect of their known requirements there is no incentive for them to release unused capacity (again because there is no ongoing cost signal for the reserved capacity at the boundary of the development). This is particularly pertinent for larger sites where development may take place in many phases, over many years, and with an uncertain end date.
- Existing IDNO arrangements already do nothing to discourage excessive capacity reservation and hoarding of available capacity on existing DNO assets. It is totally inappropriate to expand these arrangements as an unintended consequence of changing the connection boundary. In addition to the effects of inefficient network utilisation and development, there are competition concerns that need careful consideration. Any capacity secured and hoarded by an IDNO in a particular location prevents other competitors from using that capacity to offer customer connections, thereby stifling competition.
- Proposals to incentivise DNOs to invest in anticipation of a wider network need to ensure that the capacity created is used efficiently for connectees and general load increases from existing customers (e.g. electrification of transport and heat) and associated arrangements need to ensure that such additional capacity is not unduly secured and hoarded for specific speculative development projects by IDNOs or other parties. A number of non-traditional solutions may need to be considered, such as:
  - Focusing on individual end user requirements regardless of whether these customers are connected to the DNO or an IDNO.
  - Creating new DNO/IDNO relationships more akin to the ESO/DNO relationship (i.e. introducing an obligation to have a coordinated approach).

— Requiring IDNOs to provide security for larger DNO reinforcement schemes to protect DUoS customers from funding unnecessary reinforcement/flexibility contract if the capacity on the IDNO site does not materialise. The security would be returned to the IDNO when their actual demand reaches their requested capacity.

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?

44. We believe that the current connection boundary arrangements provide an effective locational cost signal that is working well, with customers paying their fair share of the costs they impose on the network at the optimal time of investment. If Ofgem does decide to deviate from these arrangements then it:

- should be clear on the signal that will replace the current locational signal and on what the benefit is to demand customers of that new signal because they will ultimately fund the increased connection costs via DUoS charges.
- should proceed with extreme caution in relation to the unintended consequences that this might bring in terms of inefficient development of the network (e.g. demand connectees will not need to consider whether an area has available capacity as they will not be funding the reinforcement).
- needs to justify increased DUoS costs for all demand customers due to connectees asking for bigger connections than actually required. Demand customers are effectively being asked to make connection projects more economically viable so that developers can commercially benefit.
- could provide an intention to raise capacity related DUoS charges to put more of an economic signal on customers to be efficient and not to ask for more than is needed.

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?

45. In our experience, developers prefer a high degree of certainty when making business decisions on the viability of a project and therefore have a low appetite for risk associated with the future firmness of their connection and/or the reinforcement contributions they may be asked to make. In circumstances where a connection request triggers a requirement for the connectee to contribute to the costs of network reinforcement, the current distribution connection boundary arrangements can make it challenging for DNOs to procure flexibility services to defer that reinforcement. This is because the additional network capacity created by the provision of flexibility services is only available for the time that the flexibility service is under contract. This creates uncertainty for the connectee about the firmness of their connection and/or the cost of reinforcement that they may be required to pay in the event that flexibility services can no longer be procured to increase network capacity to accommodate their connection (e.g. if the flexibility provider chooses not to renew their contract and no suitable replacement can be procured).

46. As a general principle, we agree that the greater socialisation of connections driven reinforcement costs resulting from the minded-to proposal to move to a shallower connection boundary for generation and

shallow connection boundary for demand could facilitate greater use of flexibility services to provide additional capacity. Where reinforcement costs are borne solely by a DNO the opportunity to procure flexibility to defer that reinforcement is similar to that for reinforcement driven by load growth from existing connections as the risk appetite of the connectee is no longer relevant. Therefore, a DNO can act unilaterally to procure flexibility to defer reinforcement for as long as it is economic and efficient to do so.

47. We would urge caution when setting expectations as to what level of increased flexibility procurement to defer connections driven reinforcement can be expected, at least in the upcoming RIIO-ED2 period. It is highly likely that, in many instances, flexibility services may not be the most suitable option for adding network capacity or that, due to the relative newness and illiquidity of DNO flexibility markets, suitable providers cannot be found. Even if the proposed changes to the connection boundary are interpreted as having a stimulating effect on flexibility markets, it is likely to take time for flexibility service markets to adapt to the changes proposed. We offer further thoughts on this theme below:

- Flexibility services should only be procured where they are judged the most economic and efficient solution. Flexibility services may not be the most efficient option for increasing capacity in a range of circumstances – for example if there is a high certainty of short term future load growth or other low cost asset-based alternatives are available.
- DNO flexibility markets are, currently, nascent, illiquid and highly localised. To defer connections drive reinforcement a prospective Flexibility Services Provider (FSP) must already be connected, or be ready to connect at the same network location and voltage level where reinforcement may otherwise be required. In many instances it may not be possible to find a suitable provider via a tender. However, we also acknowledge that, in the long run, the creation of additional opportunities for DNOs to seek flexibility services may help to stimulate markets.
- There has to be enough time to identify flexibility requirements, arrange a tender and agree the contract with the FSP and still meet the guaranteed standard associated with providing the connection offer to the connectee. Whereas there may be cases where this could be agreed in advance based on specific network conditions, a better alternative may be to advance investment in anticipation of wider network needs.
- The contractual arrangements, procurement processes, product definitions and ways of working developed by DNOs, or at industry level via ENA Open Networks, and the Flexible Power collaboration to support the use of DNO contracted flexibility services may need to be adapted to support the greater use of flexibility to defer connections driven reinforcement. This creates two related challenges:
  - It will take time to develop and refine procurement approaches which are fit for purpose for connections driven reinforcement use cases which are different to those commonly addressed by existing DNO flexibility services. An example of this might be the use of demand turn up or generation turn down flexibility.
  - Until these use cases and services have been fully explored and offered to market at scale, it is hard to evaluate the likely future ability of DNOs to use flexibility services to defer connections driven reinforcement or the appetite of providers to offer this service. This creates uncertainty

about future costs and, again, we would urge caution about the level of increased flexibility procurement that could be expected during RIIO-ED2 if the minded to positions are implemented.

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?

48. Yes, the HCC should be retained as it is essential in order to maintain the risk mitigation of an unfair DUoS burden for those generation projects which drive unusually high reinforcement costs. It also recognises that certain generation projects can drive high reinforcement costs, which it is not reasonable to expect the general mass of DUoS customers to fund.

49. Where reinforcement is more likely to create capacity from which other customers may benefit, then it is reasonable that some costs are funded from the general mass of DUoS customers. This will be the effect of the proposed shallower connection boundary for generation. There is a case to review the interaction with the proposed voltage rule in order to encourage generators to consider more efficient and cost-effective business decisions. Of the two options described in appendix 1 of the consultation document, the option where the HCC takes precedence is preferable as we believe it will better protect DUoS customers from disproportionate funding of reinforcement costs.

Question 3f: What are your views on the recovery of the costs associated with transmission that are triggered by a distribution connection? Does this need to be considered alongside wider charging reforms or could a change be made independently?

50. We support the continued recovery of transmission costs from connectees where they trigger work on the transmission system. These projects are typically very large in comparison to the majority of other connections. The logic of continuing with such cost recovery is similar to the logic of retaining and improving the HCC (i.e. those connectees that have a disproportionate effect on overall connection costs should react to appropriate cost signals, rather than those costs being socialised across all customers).

51. These transmission costs (also referred to as “attributable work” costs) occur when a distribution connection causes an impact on the transmission system (i.e. a specific DNO connectee drives those costs). The general mass of DUoS customers are unlikely to benefit from the work and it is likely that only other large connections at that specific location would benefit from any additional capacity created (and the Electricity (Connection Charges) Regulations 2017 (ECCR) caters for the relevant reimbursement payments to be made in such circumstances).

52. If the transmission attributable works costs, which are usually funded by the transmission connectee, were to be recovered from DUoS customers instead, this could create a disparity between a user seeking a direct connection to the transmission system compared to a user connecting to the distribution network where there is a transmission impact. The former would be required to fund these costs whereas the latter would have those costs funded by DUoS customers. This could, potentially distort competition between transmission and distribution connected generation. This would be an

adverse outcome since it would be contrary to Ofgem's stated intentions to reduce or remove artificial distortions between connections to the transmission or distribution system.

53. Should Ofgem revisit this in the future, it should be clear on how any alternative funding arrangements will work. Based on the current arrangements, as defined in the distribution licence, these costs are highly likely to be New Transmission Capacity Charges (i.e. costs that DNOs cannot pass-through via DUoS)[8]. Ofgem would need to give clear consideration to what licence changes would be made in RIIO-ED2 to ensure that DNOs are not penalised, given under current arrangements, DNOs will generally pass-through the capital cost element of New Transmission Capacity Charges to the connectee, via an upfront cost, but will bear the impact of ongoing operation and maintenance costs for the current price control period.

54. The pass-through issue could be alleviated by a 'simple' change to the distribution licence (e.g. in its simplest form, defining all costs levied by a Transmission Licensee as Transmission Connection Point Charges). It should be noted that DNOs do not capitalise pass-through costs (i.e. they do not impact the regulatory asset value (RAV) and do not include costs associated with assets they would not own in the RAV). Pass-through costs by their nature, are recovered over a short period (e.g. the DNO does not wait 45 years to recover an annual depreciated capital repayment to National Grid Electricity System Operator (NGESO)).

55. Providing we could recover these costs through DUoS, we agree with Ofgem that more locational DUoS could allow these costs to be recovered from those that drive them, rather than from the customers connected to the same part of the network. In its consultation, Ofgem suggests that more locational DUoS could target the "individual causing the work". From our understanding of what Ofgem has considered, from heavy involvement in the subgroup work, the 'individual' would only ever be targeted if that individual was the only customer connected at a grid supply point (GSP). Otherwise, the modelling approach that we supported development of, would allocate all Transmission Connection Point Charges to any 'locations' served by that GSP – i.e. the customer may be connected at one primary substation but customers connected to all primary substations fed by that GSP would pick up the costs (assuming locational granularity down to primary substation, but the principle applies to bulk supply points etc.).

56. We believe it is essential that Ofgem considers this issue alongside wider charging reforms given the need to better target these costs to the relevant individuals has not been fully developed, and Ofgem appear to believe that this will not be possible in time for implementation in April 2023. This links to the points we have made in answer to question 3a that significant changes to legislation, regulation and industry codes are necessary within challenging timescales.

[8] New Transmission Capacity Charges are where: (i) pursuant to the requirement of the DNO (whether driven by a customer connecting to the distribution network or not); and (ii) for a new or reinforced connection point; and (iii), the relevant assets have been energised within a price control period, such costs cannot be passed through by the DNO via DUoS charges. On the other hand, Transmission Connection Point charges can be passed through via DUoS charges.

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

57. If Ofgem's reforms as determined by its final decisions have the overall intended outcomes of its minded to proposals, it is reasonable to assume that the proposed connection boundary options will lead to an increase in both applications for and acceptances of connections. We see no reason to expect a reduction in the number of project cancellations, if the proposed connection boundaries come into effect as it may be more attractive to accept a project at a reduced cost. We are unaware of the key drivers on project cancellations as that is a commercial consideration for the connecting customer (i.e. whether this is due to other economic factors or the initial project investment costs).

58. It is possible that subsequent connections could utilise the original DNO investment but the ECCR would not apply if first a connection was not made. However, this depends on a number of factors such as: the location and type of asset and any technical features in the specification to cater for the applicant's requirements that may not be suitable for general usage by subsequent connectees.

59. We support the idea of reasonable liabilities/securities being placed on the customer in the event that they cancel or delay their projects. This would ensure that the DNOs have enough information to plan and develop the network economically and efficiently and protects the wider customer base to an extent from unnecessary cost. It gives connectees an incentive to provide accurate and timely information about their needs and ensures some of the risk of stranded assets is held by the parties that are best placed to mitigate and manage such risk. It would also provide an incentive to connectees, who may face a lower risk acceptance, to be more certain about their projects, whilst ensuring that some of the risk of stranded assets is managed efficiently.

60. The idea of liabilities/securities is that the connectee provides security to cover a proportion of the liability prior to the start of any works on the connection (i.e. the connectee does not secure the full liability which in turn minimises the overall cost thereafter). It provides protection for DUoS customers against speculative projects where demand did not materialise from the project, so the DUoS funded reinforcement expenditure was not necessary.

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?

61. We believe that any conflict between Ofgem's reforms and the ECCR must be resolved before the proposed reforms are implemented.

62. For example, where regulation 7(1) of the ECCR applies, the distributor must:

- Under regulation 7(2), demand a reimbursement payment from the person obtaining the second connection;
- Under regulation 7(3), ensure that the reimbursement payment demanded is

  "for an amount equal to the appropriate proportion of the net first connection expenses"

; and

- Under regulation 7(4), calculate the appropriate proportion of the net first connection expenses as the proportion of those expenses which appears to the distributor to be reasonable having regard to all the circumstances.

Net first connection expenses is defined as

> "…the first connection expenses, excluding (a) if the second connection is a LV connection, any expenses which were incurred in providing electric line or electrical plant at a nominal voltage of more than 22kV for reinforcement works for the purpose of making the first connection; or (b) if the second connection is a HV connection, any expenses which were incurred in providing electric line or electrical plant at a nominal voltage of 132kV for reinforcement works for the purpose of making the first connection".

The distributor must, therefore, calculate the net first connection expenses for the purposes of demanding the reimbursement payment in accordance with that definition.

The consultation states that both the shallower and shallow connection boundary will be achieved by amending the voltage rule, which is a licence condition and part of the CCCM. It appears to us, therefore, that this will create a conflict between the proposed reforms and the distributor's obligation to calculate the reimbursement payment in accordance with the ECCR.

Consequently, if the ECCR are not amended to resolve that conflict, the distributor will be obliged to calculate the reimbursement payment in accordance with the ECCR regardless of the outcome for either the eligible person or the person requiring the second connection.

63. We do not factor the effects of the ECCR into our decision-making when preparing a quotation for the provision of a connection because the requirements of the ECCR are separate to that process. For example, the person requiring the second connection must make the reimbursement payment to the distributor in addition to and separately from the cost of the distributor providing the connection.

64. We believe that Ofgem's policy and the ECCR can work together most efficiently only if there is no conflict between them.

65. We note that one of the key problems that Ofgem is seeking to address is that charges for connection can create free riding behaviours and lead to unfair outcomes. Furthermore that:

> "*incentives to free ride could, amongst other things, delay or inhibit the uptake of low carbon technologies, negatively affecting efforts to achieve net zero*'. The consultation also states that '*Generators are generally unwilling to pay towards reinforcement, so are left to choose a reduced capacity or non-firm connection. Alternatively, and subject to the ECCRs, generators that can delay are able to free ride on those willing to pay for reinforcement*"

We have two issues with this position, namely:

- Currently, where a customer seeks a connection that requires the DNO to reinforce the network, subject to the common connection charging methodology (CCCM), that customer pays an apportioned amount towards the reinforcement (i.e. any spare capacity is funded by the DNO via DUoS charges, so subsequent connections cannot '*free ride*' on the first connectees capacity); and

- Given the ECCRs provide for eligible persons to receive a payment if they have funded assets that are used by a subsequent connectee connecting within a 10-year period after the first connection, then it is difficult to justify Ofgem's '*free rider*' argument.

66. In our view, the interactions between the proposed connection reforms and the ECCR must be resolved before the implementation of any revised connection boundary. There are a number of key conflicts which need to be considered, including:

- Where a DNO is an Eligible Person (i.e. the DNO has partly funded reinforcement), the ECCR 2017 places an obligation on the DNO to demand a reimbursement payment from the person obtaining the second connection. Under a shallow connection boundary a demand customer will not contribute towards reinforcement but the DNO is obligated to demand a reimbursement payment (i.e. the DNO has no legal discretion). Any change to the DNOs licence or the CCCM could not take precedent over the ECCR.
- The consultation states that both the shallower and shallow connection boundary will be achieved by amending the voltage rule which is a DNO licence condition and part of the CCCM. The ECCR also contains the current voltage rule in the definition of 'net first connection expenses' so this definition would also need updating.
- The ECCR may also need to differentiate between demand and generation connections as only the latter would be required to make reimbursement payments under the proposed shallower connection boundary.

67. The ability to factor in the effects of the ECCRs into decision making, given the levels of uncertainty around subsequent connectee(s), will differ depending on whether the eligible person is a DNO or a connecting customer.

- A key condition of the ECCR is that there has to be a first connection in order to be able to demand reimbursement payment, so where a DNO fully funds reinforcement with no associated connection, then the DNO cannot recover any of the investment costs. Another example would be a customer who funds infrastructure without any end connections. The proposed connection boundary options are intended to facilitate investment in anticipation of wider network's needs, so if this investment is 100% DNO funded then, even under a shallower generation connection boundary, the DNO will not be able to recover investment costs and refund the general mass of DUoS customers (deduction from the RAV). In this situation there is no benefit to the general mass of customers who funded the work unless they required a modified connection.
- Where a party is the first connection, there may be a number of factors to consider (and reference to the ECCR assumes all the ECCR legal provisions have been considered).
  - Decision making and levels of uncertainty may depend on how well informed a customer is (e.g. larger projects and repeat developers are likely to be better informed about ECCR than one-off smaller developers (we cover ECCR in our offer letters and are happy to explain it to customers).
  - Developers could take a worst case position and assume there will be no subsequent connections (there will be a number of other factors, e.g. location, likelihood of other developments etc.).

  - Extension assets associated with a connection will continue to operate the same for demand and generation connections.
  - The treatment of reinforcement costs associated with connections will depend on whether a connection is demand or generation as only the latter can be eligible or liable for reimbursements payments. There are circumstances detailed in the CCCM where a party pays the full cost towards reinforcement, and if this was a generator they would only be eligible for reimbursement from future generators and not demand connections.

- One of the options being explored would be for the DNO to demand the reimbursement payment from the second comer and provide an equivalent refund. However, the DNO has no alternative but to act in accordance with the current regulations so there are conflicts that need to be addressed. Consider a scenario where, under the minded to proposals, the first connectee isn't eligible to receive a reimbursement and the second connectee isn't required to make one.
  - The ECCR obligates the DNO to demand a reimbursement payment, so the option being explored would involve the DNO demanding a reimbursement payment from the second connectee and then refunding it (through some mechanism yet to be defined).
  - The ECCR also obligates the distributor to 'apply a reimbursement payment' (i.e. pay the eligible persons 'as soon as reasonably practicable' to comply with the regulations). Despite the fact that the DNO has refunded the reimbursement payment, it is still obligated to make a reimbursement payment to the first connectee. So if the DNO is invoicing and refunding the second connectee does this mean they have to refund and invoice the second connectee?

68. We will continue to work with Ofgem and other DNOs to resolve any conflicts between Ofgem's minded to policy and the ECCRs to ensure that they work together efficiently but we consider that the proposed minded to position will require a detailed review of the ECCR to achieve that outcome.

69. However, Ofgem should be mindful of the impact this may have on the proposed implementation date of April 2023, given the time that will be required to undertake that review and for the legislative process to be completed.

3. Responses to specific questions on Ofgem's proposals for definition and choice of 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?

70. Yes, we agree that transparent and clearly defined non-firm access choices may further support efficient network development and utilisation. In developing the definition of firm access, we think that it is important to differentiate between the "firmness" that is associated with the number of connections between a customer and the distribution network, and the "firmness" that is associated with access to the wider system. Historically, the term "firm connection" has been understood by customers to relate to having two connections to the distribution network. ANM schemes that provide curtailed/non-firm access have already delivered quicker and more efficient connections, with appropriate levels of curtailment, while minimising socialised reinforcement costs. We think generation and storage customers have a strong preference for non-curtailed access, and that this preference would be enhanced with a shallower connection boundary. We believe there is still a place for curtailed access choices via non-firm arrangements so that further generation and storage can be connected more quickly and more cheaply alongside, or ahead of, the anticipated rise in demand from the electrification of heat and transport. Responses to Ofgem's consultation from generation and storage stakeholders should be particularly informative in the context of whether they see continued value in non-firm access or whether reduced reinforcement costs through changes to the connection charging boundary will drive more appetite for non-curtailed connections.

71. It would be helpful for Ofgem to further clarify in its final decision the context of non-firm access as explored in the work of the access sub-group (i.e. how non-firm access relates to curtailment and the allocation of capacity on shared use assets on the wider network). As indicated in the consultation, loss of supply or increased levels of curtailment due to maintenance, network damage or faults, are a separate matter and an inevitable but infrequent, consequence – especially where customers (typically generators) opt for connections with single circuit dedicated assets to reduce connection costs. Further design work should be considered in conjunction with work already undertaken under ENA Open Networks workstream 1A.

72. There would be costs associated with providing more detailed curtailment estimates and post-use curtailment measurement, so the design of non-firm access choices will need to be proportionate, cost efficient and standardised, where possible. There is also a need to try and ensure that the necessary costs of systems and processes, administration and specialist technical resources, do not outweigh the network efficiency benefits. We are currently evaluating the potential impact of the proposed arrangements on our RIIO-ED2 final business plan.

73. Whilst we can see that limiting the curtailment metric to "percentage of hours curtailed" avoids the risks associated with the DNO estimating the energy that the new connectee may be unable to import/export, the risk associated with the levels of import/export associated with pre-existing customers would still rest with the DNO under these proposals. Based on the assumption that curtailment will predominantly be associated with generation, we think that consideration should be given to developing standard export profiles from common types of generation facilities, so that the

curtailment assessments can better reflect the capacity on the distribution network itself rather than on the behaviour of other customers connected to it. An assessment as to whether the DNO complied with the agreed "percentage of hours curtailed" would be made using these standard profiles. The design of non-firm access choices and supporting principles should be developed through further Ofgem-led working group activity as part of the SCR.

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?

74. Yes, we see value in having time-profiled access as a choice available to customers requesting a connection. However, in the absence of DUoS reforms we think interest from existing customers will be very limited. As for our answer to question 4a, reduced reinforcement costs through changes to the connection charging boundary may drive more appetite for non-curtailed connections rather than more flexible connections. Again, the design and supporting principles for time-profiled access should be developed through further Ofgem-led working group activity as part of the SCR to ensure a standardised approach and implementation.

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

75. No, we have not identified any additional benefits beyond potential network utilisation efficiencies. We appreciate why Ofgem is not proposing to take forward shared access as part of the Access SCR, given the risks and practicality issues identified by Ofgem as a result of the previous working group activity.

76. However, we believe that there may also be issues stemming from Section 16 of the Electricity Act, which provides for a 1:1 relationship between the connecting customer (which is the owner or occupier of the premises concerned) and the DNO, whereby the connecting customer proposes the capacity (maximum power) for the connection and the DNO may make counter-proposals in that respect. Section 16 of the Electricity Act does not provide for a party that is not the owner or occupier of the premises concerned (e.g. a "Sharing Group Manager") to have a relationship with the DNO for access to the combined capacity (maximum power) for a group of connectees.

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)?

77. We have a strong preference for reflecting the cost of the firmness of access rights choices for new customers in connection charges, as we believe that such cost signals are best applied only once and at the time of initial investment, when a DNO has a direct relationship with the connectee. As potential DUoS reform is better understood, there may be the opportunity, provided that the implementation is both practical and proportionate, to encourage a change in behaviour from existing customers via the introduction of time of use capacity charging arrangements in DUoS to support time-profiled access rights choices.

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

78. We understand that Ofgem cannot resolve all the open issues at once. As stated in response to the earlier questions we are concerned about the forward looking charge decisions remaining unresolved. We have no such concerns for new transmission access choices.

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

79. Yes. If Ofgem's final decision is to go ahead with non-firm and time-profiled access right choices, the required design work on supporting principles and standardisation should be achieved through Ofgem-led working group activity as part of the SCR, rather than being industry-led or transferred to other working groups (including any work already being undertaken and led by industry).

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

80. The proposed timescale for the implementation of non-firm and time-profiled access choices of 1 April 2023 is challenging but should be achievable via Ofgem-led working group activity to deliver the scope of the minded to proposals (i.e. currently excluding any DUoS reform). It may be useful for Ofgem to capture a specific set of SCR evaluation and implementation principles for the two access choices within some proposed working group terms of reference, informed by responses to this consultation. If responses to this consultation are clearly supportive, it would be prudent for the necessary work to start in late summer 2021, rather than initiating the work as part of the final decision. Ofgem would do well to identify the long timescale items in the implementation plan at an early stage. As mentioned earlier, we consider that some key points that Ofgem needs to consider are licence modifications, resolving conflict with the ECCR, updating the common connection charging methodology and potential code changes.

4. Responses to specific questions on Ofgem's 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?

81. No. Exports from smaller generators of all sizes contribute to flows that occur at the boundary between the DNO's network and the transmission system.

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?

82. We recognise the logic, set out in paragraph 5.12 of the consultation, including for administrative purposes for establishing the threshold at 1MW.

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

83. No, the impacts of generation connected to DNO assets at a GSP or a generator directly connected at a GSP via transmission owned assets would be broadly the same.

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?

84. We have no comment to make. Perspectives provided by those stakeholders who are much more familiar with the detail of transmission charging arrangements will clearly be valuable to Ofgem.

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?

85. We have no comment to make. We think this question is best answered with those that would be directly impacted.

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?

86. Yes, we believe Ofgem has identified all the core options for administering TNUoS should they be applied to SDG. We agree with Ofgem that the DNO-led model appears to be unnecessarily complex and onerous, when compared to a NGESO or supplier-led option. A DNO-led solution would require the creation of new ongoing commercial payment arrangements between the DNO and the end users when such arrangements between the suppliers and their customers already exist. Implementation timescales and costs would be adversely impacted by the need for DNOs to make considerable changes to billing systems to support the collection of TNUoS.

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?

87. Ofgem rightly recognises the challenges that its minded to proposals will have for some customers and how this aligns with its third guiding principle that any changes are practical and proportionate. Ofgem also rightly recognises the impact TNUoS reform could have in terms of Northern SDG facing charges whereas Southern SDG may receive credits.

88. We sympathise with generators, in particular SDG, seeking to make investment decisions considering Ofgem's minded to proposals. Generators should be wary of the impacts highlighted within the consultation (increases and decreases), but should also be cognisant of the impact DUoS reform could have (e.g. Northern SDG may face TNUoS charges and, subject to DUoS reform, may face DUoS charges rather than credits if they locate in a generation dominant area). In general, we do not believe that customers have been presented with enough information about the potential impact of decisions that Ofgem has not yet made. For example, whilst we do not disagree with the information Ofgem presents in Table 1 of the consultation, the outcome could be very different depending on Ofgem's DUoS proposals (e.g. benefits arising from time-profiled access right choices, and/or the impact of its SDG proposals, could be offset or compounded by DUoS reform).

89. Given the uncertainty, we agree with Ofgem that it should consider a wider review of TNUoS. We have previously communicated to Ofgem, as part of the Targeted Charging review SCR, our concern over the growing size of the TNUoS 'residual' (i.e. how can a cost-reflective charging methodology result in revenue recovery from 'top-up' charges greater than 80%?).

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

90. We have included additional information in our "Introduction and general observations" section.