Consultation

ofgem
Making a positive difference
for energy consumers

Access and Forward-looking Charges Significant Code Review: Consultation on Updates to Minded to Positions and Response to June 2021 Consultation Feedback

Subject	Details
Publication date:	24 January 2022
Response deadline:	21 February 2022
Contact	Patrick Cassels, Head of Electricity Network Access
Team:	Electricity Network Access
Telephone	0207 901 7000
Email:	FutureChargingandAccess@ofgem.gov.uk

In June 2021, we consulted on our minded to positions for three key policy areas within the scope of our Access and Forward-looking Charges Significant Code Review: distribution connection charging, the definition and choice of access rights, and transmission charges for small distributed generators. That consultation closed in August 2021, and we publish the non-confidential responses alongside this document.

This further consultation sets out updates to our minded to positions that respond to the feedback we received. It reaffirms the high-level proposals we put forward for distribution connection charging and access rights, offering opportunity to comment on additional details and clarifications. It also outlines that we no longer intend to direct changes to transmission network use of system charges under the Access SCR, including the application of these charges to small distributed generators.

We would like to hear the views of people with an interest in the areas outlined above. We particularly welcome responses from users of the electricity network who these proposals may affect, alongside other stakeholders and the public.

This document outlines the scope, purpose and questions of the consultation and how you can get involved. Once the consultation is closed, we will consider all responses. We want to be transparent in our consultations. We will publish the non-confidential responses we receive alongside a decision on next steps on our website at Ofgem.gov.uk/consultations. If you want your response – in whole or in part – to be considered confidential, please tell us in your response and explain why. Please clearly mark the parts of your response that you consider to be confidential, and if possible, put the confidential material in separate appendices to your response.

Any enquiries related to the text of this publication should be sent to Ofgem at:
10 South Colonnade, Canary Wharf, London, E14 4PU. Alternatively, please call Ofgem on 0207 901 7000.

Contents

Executive summary

In June 2021, we issued a consultation on our minded to positions for three key areas of our Access and Forward-looking Charges Significant Code Review: distribution connection charging, definition and choice of access rights, and transmission charges for small distributed generators.[1,2] The policy areas and positions we consulted on were:

- **Distribution connection charging boundary**. We were minded to reduce the contribution to reinforcement within the upfront connection charge for generation, and to remove it completely for demand.
- **Access rights**. We were minded not to proceed with shared access and instead introduce access rights choices to the distribution network based on levels of firmness and time-profiled access.
- **Transmission Network Use of System charges (TNUoS)**. We were minded to introduce changes to the charging regime so that Small Distributed Generators (SDG) would also face wider TNUoS generator charges.

We received 153 responses, and we have been considering this feedback in the further development of our policy proposals. Responses were submitted by over 125 unique organisations, the biggest groups of which were small or independent renewables generators, trade associations, and charities or community energy groups. We thank all respondents for their valuable input and the high overall level of engagement with our consultation. Responses that were not marked as confidential are published alongside this document.

This document includes a summary of the feedback we received and how we have responded to it. It also includes additional details on our updated proposals and a further opportunity for input via response to additional consultation questions.

[1] June 2021 Consultation on Minded to Positions: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[2] The terms "the Authority", "Ofgem", "we" and "us" are used interchangeably in this letter. The Authority is the gas and electricity markets authority. Ofgem is the office of the Authority.

Table 1 summarises the views that stakeholders provided on our proposals. Further details of this feedback how we have responded can be found in the corresponding policy sections.

Table 1 – Summary of feedback from June 2021 Consultation on Minded-to Proposals

Policy area	Overall level of support	Summary of supportive comments	Summary of mixed and unsupportive comments
Distribution connection charging boundary	• A majority of respondents supported our proposals. • A large minority of respondents offered neutral or mixed support. • A small minority of respondents did not support our proposals.	• Strong support for a general move towards a shallow connection charging boundary. • General agreement that proposals reduce the barriers to investment in low carbon energy resources and facilitate GB energy system net zero objectives. • General agreement that proposals help to enable a more strategic approach to network development.	• Full impact of overall package of reform is difficult to assess without clarity on changes to Distribution Use of System ('DUoS') charges. • Removal of the existing 'High Cost Cap' for generation and lack of cost disincentives for demand could lead to inefficient investment, and further DUoS bill payer protections may be needed. • Calls to 'grandfather' aspects of existing arrangements for some users to minimise disruption of implementation.
Distribution network access rights	• A majority of respondents supported our proposals. • A minority of respondents offered neutral or mixed support. • No respondents indicated that they were wholly unsupportive.	• Proposals should provide better clarity for DNOs (Distribution Network Owners) and developers seeking new connections • Main benefit of proposals should be increased speed of connection. • Options should provide greater flexibility to the energy system.	• In the absence of DUoS reform, some benefits of these proposals may be blunted. • Proposals have benefits for enabling more renewables to connect in the short-term but do not provide a suitable long-term option. • Concerns with lack of detailed information on curtailment.
Transmission network charging (including charges for small distributed generators)	• Few respondents supported our proposals. • Some respondents offered neutral or mixed support. • A large majority of respondents did not support our proposals.	• Small distributed generation can and does contribute to flows on the electricity transmission system equivalent manner to larger generators and should be charged on that basis. • It is fair that distributed generators captured by our proposals should be charged in an equivalent manner.	• Significant opposition from some stakeholders who state that renewable generators in remote areas will be disproportionately affected by these changes. • A range of strongly felt arguments that the broader TNUoS regime requires more fundamental review before this change is considered.

The positions put forward for consultation in this document build on the high-level proposals from our June 2021 minded to positions. The purpose is to ensure stakeholders have opportunity to comment on further detailed aspects of our proposals relating to the distribution connection charging boundary and access rights, and that they are notified of our updated position on transmission charging. Our revised positions are in direct response to many of the emergent themes, comments and requests for detail received in response to our original consultation.

To support the development of this consultation, in the interim period, we asked the Access SCR Delivery Group to facilitate two working groups to consider the detailed implementation of our connection charging boundary and access rights minded to positions.[3] We asked these groups to provide Ofgem with a series of recommendations on any areas of outstanding detailed policy development necessary to ensure effective implementation of our proposed reforms.

The recommendations put forward by these working groups, provided to Ofgem directly and operating under the Delivery Group, have helped to inform and refine the updates we propose. We are now seeking further input from wider stakeholders, which will inform our final decision and direction for code modifications to be raised. We intend to hold a briefing session for Challenge Group members on 4 February to walk through the additional detailed updates to our proposals, including our rationale for further consultation. The slides will be made publicly available on the Charging Futures Forum website.[4]

Outside of this consultation, we are continuing to review responses to our consultation on descoping DUoS reform from the Access SCR and initiating a separate SCR to take these reforms forward. That consultation closed in December 2021, and we expect to publish a decision on this area before our final Access SCR decision and direction.[5]

Table 2 summarises the high-level policy changes that we intend to direct, accounting for the additional updated proposals and clarifications put forward in this consultation.

---

[3] The roles and membership of the Access SCR Delivery Group and Challenge Group were defined in our original SCR launch statement: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision
[4] Charging Futures Forum website: http://www.chargingfutures.com/
[5] Consultation to descope the wide-ranging review of DUoS from the Access SCR and take it forward under a dedicated SCR: https://www.ofgem.gov.uk/publications/consultation-our-proposal-take-forward-reform-distribution-use-system-charges-under-separate-significant-code-review-revised-timescales

Table 2 - Summary of additional areas of consultation and high-level proposals

Policy area	High-level policy changes proposed for April 2023 implementation	Updated details of proposals and clarifications included in this consultation
Distribution connection charging boundary	• **A 'shallow' connection charging boundary for demand**, where the connecting customer would no longer receive a connection charge for reinforcement of the shared network, and only for their extension assets. • **A 'shallower' connection charge for generation**, where the connecting customer would receive a reduced charge for reinforcement of the shared network, plus their extension assets. • **Protections for DUoS bill-payers** that require the connecting customer to contribute more to the cost of connection under some specific circumstances. We think these measures will help to protect DUoS bill-payers from the potential for large overall cost increases as a result of these changes.	• Additional proposals on the details of DUoS mitigations, including: i Retention of a High Cost Cap for generation connections. ii Introduction of a High Cost Cap for demand connections. iii Proposed calculation of the caps using the voltages at point of connection, plus one above. iv Proposed principles for the setting of the demand High Cost Cap. • Additional detail on proposed DUoS mitigation for the treatment of three phase connections. • Additional detail on proposed DUoS mitigation, the treatment of speculative developments. • Updated our position on storage under our proposed changes to the charging boundary – that storage connections are treated in line with generation for connection charges. • Clarified our expectation that amendments to the terms of the Electricity (Connection Charges) Regulations will be required to give effect to our proposed boundary changes. • Clarified our proposals that connection boundary changes would not affect terms for existing/in-flight projects. Projects seeking to re-apply under new arrangements would not retain their queue position upon re-application. • Clarified that we are not considering the introduction of rebates for users who have paid reinforcement costs prior to these proposed connection charging changes. • Clarified our proposal that existing non-firm connections seeking a firm connection under the new arrangements will not be prevented from doing so, and that DNOs should continue to manage connection applications through their queue management processes. • Clarified our expectation that no code changes are required to enable additional consideration of interactivity between projects. • Clarified our expectation that the Minimum Scheme definition of least capital cost should not be affected by the proposed charging boundary changes. • Clarified our expectation that the 'point of connection' definition will remain unchanged. • Clarified proposed licence mitigations for DNOs who may experience a greater number of connection applications following 1 April 2023 implementation date.

Distribution network access rights	• **Non-firm access arrangements** available to customers and defined in terms of number of hours (% of time) that a connecting customer has agreed to be curtailed. • **Curtailment limits for non-firm connections**, agreed between the network operator and the connecting customer based on maximum overall network benefit. If a network operator needs to curtail above this limit, that service must be procured from the market. • **End dates for non-firm arrangements** after which the connection needs to be made firm unless a customer has not requested a firm connection or where the high-cost cap is triggered, and the customer does not wish to contribute to reinforcement costs above the cap.	• Clarified the definition of curtailment as any action taken by the distribution network operator to restrict the conditions of a connection, except where this restriction is caused by a fault or damage to the distribution system which results in an interruption to the customer's supply. • Clarified that restrictions due to constraints on the transmission network that are outside of the control of the distributor are not considered curtailment for the purpose of better definition of distribution network access rights. • Clarified that curtailment limits are to be offered by the network operator on the basis of maximum overall network benefit and agreed with the connecting customer. • Clarified actions required by the network operator should the network operator exceed the agreed curtailment limit. • Introduction of explicit end-dates for non-firm arrangements to ensure that network operators invest in network capacity in a timely way and provide certainty to customers on when their connection arrangements are likely to be made firm.
Transmission network charging (including charges for small distributed generators)	• **We recently launched a Call for Evidence on TNUoS** relating to the potential for wider changes to the charging methodology.[6] • **We stand behind the principle that smaller generators should pay charges equivalent to larger generators** where they have an equivalent impact on the network. • **We <u>do not</u> intend to direct changes to TNUoS for April 2023 implementation under the Access SCR** whilst the possibility of broader changes to TNUoS charging arrangements and Call for Evidence responses are still under consideration. We intend to revisit this policy area once the way forward for potential broader change is clear.	• We are not presently consulting on any additional policy proposals in this policy area in light of our recent Call for Evidence on Transmission Network Use of System Charges, which we encourage readers to review in lieu of further consultation questions in this document. • We are currently assessing the responses to that Call for Evidence alongside the responses to our June consultation and working across Ofgem to determine the best way forward. We expect to share more information in due course. • We are seeking your views on confirmation that we do not intend to direct changes to TNUoS for April 2023 implementation under the Access SCR.

[6] Ofgem Call for Evidence on Transmission Network Use of System charges, published October 2021: https://www.ofgem.gov.uk/publications/tnuos-reform-call-evidence

1. Introduction

Context and reminder of case for reform

1.1. We launched the Access SCR in December 2018, because we thought that the current electricity network access arrangements and forward-looking charges needed to adapt to deliver and facilitate the cost savings of a more dynamic and flexible energy system.

1.2. The Access SCR reforms will be an enabler of Ofgem's strategic priorities, including enablement of investment in low carbon infrastructure at a fair cost, and the delivery a more flexible electricity system.[7] Making the best use of network capacity and having effective signals that reflect how users create costs and savings on the network is critical to the development of a flexible and dynamic future energy system. These arrangements will be key to accommodate new technologies and facilitate the decarbonisation of the energy system in an efficient way.

1.3. The Access SCR reforms are also consistent with our enduring regulatory priorities to protect the interests of consumers, support vulnerable consumers and advance decarbonisation. The objective of the SCR is to ensure that electricity networks are used efficiently and flexibly, reflecting users' needs and allowing consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general. There are significant potential savings from a more dynamic and flexible system. There could also be significant wider system savings through ensuring there is a level playing field for different types of energy service providers to compete on.

1.4. The scope of the SCR includes:

- A review of the **distribution connection charging boundary**
- A review of the **definition and choice of access rights**
- A focused review of **Transmission Network Use of System (TNUoS) charges**
- A wide-ranging review of **Distribution Use of System (DUoS) charges**

[7] Ofgem's strategy and priorities can be at the following location (based on 21/22 Forward Work Programme at time of publication): https://www.ofgem.gov.uk/about-us/our-strategy-and-priorities

1.5. We outlined in our June 2021 consultation that, due to the strong linkages between our Full Chain Flexibility strategic change priority and some of our Access reforms, we had decided to pause further assessment of DUoS reform options and we signalled the need for further clarity on the broader direction of this work to ensure our reforms are aligned.[8] This is further discussed at 1.16.

1.6. We did not think there were the same dependencies between the Full Chain 111.5 programme outcomes and our other reforms, and we put forward proposals relating to:

- **Distribution connection boundary** reforms. These affect the DNOs' allowances under the price control, and we saw benefit in signalling any proposed changes in time for them to be reflected in business plans

- **Access rights** reforms. We thought it would be low regret to progress with these now, as they are opt-in for connectees and can provide flexibility for DNOs and users to agree more beneficial access to the network.

- **TNUoS** reforms. Notably, the application of TNUoS generation charges to small distributed generation.

1.7. We believe that the changes we are proposing to the distribution connection boundary and network access rights are complementary. Together, they would enable more efficient use of and investment into the distribution network, supporting the growth of low carbon technology required for net-zero. We also believe that they are a necessary enabler for future DUoS reforms.

1.8. We also want to realise the value of a more cost-efficient network over time. We believe that our proposals will encourage network operators to take a more strategic approach to network planning and reinforcement. This includes investing ahead of need where it is efficient to do so and considering alternative approaches to reinforcement to meet the capacity needs of customers.

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

1.9. The move to a shallow connection charging boundary for demand (and shallower for generation) enables whole system cost savings in alignment with more strategic development of the network, economies of scale, better coordination/timing, use of non-build options, opportunities to optimise capacity utilisation between load and generation. As the distribution network is expected to become more constrained with the electrification of heat and transport, we consider that these changes will enable more efficient network development.

Our process to date

1.10. A timeline of key milestones in the development of our proposals is set out below:

- **December 2018:** Scope clarified in formal SCR launch
- **September 2019:** Update on options long-list in summer working paper
- **December 2019:** Update on options long-list in winter working paper
- **March 2020:** Outline of shortlisted options
- **June 2021:** Consultation on minded to positions
- **January 2022:** Consultation on updates to minded to positions and response to June 2021 consultation feedback (this document)

1.11. In publishing this further consultation, we have not reiterated all the original proposals that we put forward in our June 2021 consultation, which continues to represent our positions unless specified otherwise in this update.

1.12. The additional details and clarifications we express relating to the **distribution connection charging boundary** and **access rights** represent the most recent version of our proposals, largely building on the positions we articulated in June 2021 in more detail.

1.13. Our updated proposals for **transmission network charging**, specifically, that we do not intend to direct changes to TNUoS for April 2023 implementation under the Access SCR (including changes to apply TNUoS charges to small distributed generation), supersede the proposals from our June 2021 consultation.

1.14. Considering these further updates to our Minded to Positions, the Impact Assessments we published as alongside our original June 2021 consultation continue to remain valid for the additional detail in this document for all areas other than TNUoS charges, as that aspect of the Impact Assessments is no longer relevant to our updated position. The analysis which informed the Impact Assessments was conducted by policy area without interdependency and, as we no longer intend to direct changes to TNUoS under the Access SCR, sections 1.3, 4 and 5 of the Impact Assessments are no longer relevant.[9] All other parts of section 1, section 2, and section 3 continue to be relevant to our proposals and the level of additional detail and clarification in this document does not materially impact the assessments that were conducted in advance of our original consultation.

1.15. We recognise, however, that the additional details we include in this document may affect the responses that some stakeholders provided to our first consultation. We therefore continue to welcome comments on our full suite of proposals, and we offer stakeholders an opportunity to revise any views previously submitted. The full list of consultation questions can be found at the end of this document (**section 5**).

Wide-ranging review of Distribution Use of System (DUoS) charges

1.16. In September 2021, we communicated to the Charging Futures Forum that we no longer felt that it was the right approach to direct DUoS charging reforms alongside the other areas of the Access SCR in a single direction.[10] We outlined, however, that we still felt that the wide-ranging scope of our DUoS reforms was important and necessary.

1.17. In November 2021 we published a consultation on descoping the wide-ranging review of DUoS from the current Access SCR and taking it forward under a dedicated SCR with a revised timescale.[11] Our consultation closed in December 2021, and we are reviewing the responses. We intend to issue a decision on a DUoS SCR before our final Access SCR decision and direction.

1.18. As part of our DUoS SCR consultation, we identified linkages between the existing Access SCR and our proposed DUoS SCR. These included the balance between locational

[9] June 2021 consultation documents, including Impact Assessments: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[10] Material presented at September 2021 Charging Futures Forum: http://www.chargingfutures.com/about-charging-futures/charging-futures-forum/22-september-2021-forum-webinar/
[11] Consultation to descope the wide-ranging review of DUoS from the Access SCR and take it forward under a dedicated SCR: https://www.ofgem.gov.uk/publications/consultation-our-proposal-take-forward-reform-distribution-use-system-charges-under-separate-significant-code-review-revised-timescales

signals sent in the connection charges versus ongoing use-of-system charges, and time-profiled access rights which may be able to signal periods of network constraint.

1.19. In section 2.82 of this consultation, we outline details of a proposed DUoS mitigations that will interact with any future DUoS arrangements. These include proposals for a high cost cap, and the treatment of both three-phase and speculative connections (explained in further detail in those sections).

1.20. Retaining these areas within the scope of any future DUoS work will enable us to ensure that these mitigations remain effective once the direction of DUoS changes is clear. There may be a case to amend or remove some or all mitigations, dependant on the specific details of any future DUoS reform proposals.

1.21. We therefore consider that these areas of our connection charging boundary proposals will continue to fall within the scope that we set out in our DUoS SCR consultation, enabling the arrangements we propose to be reviewed alongside any future DUoS reform proposals.

2. Distribution connection charging boundary

Section Summary

This section provides further details on our June 2021 minded to proposals on the connection charging boundary for demand and generation distribution network connections.

We confirm our proposals to introduce a 'shallower' connection charging boundary for generation and a 'shallow' connection charging boundary for demand. In addition, we propose additional measures to ensure DUoS bill payers are better protected against the potential high cost impacts of reinforcement driven individual connecting customers.

Consultation questions on distribution connection charging boundary proposals

Question 2a:

- **i.** Do you believe that it is necessary to introduce a High Cost Cap (HCC) for demand, and to retain one for generation?
- **ii.** Do you believe that our proposals to do so represent sufficient and proportionate protection for DUoS billpayers against excessively expensive connections driven reinforcement?
- **iii.** What are your views on retaining the current 'voltage rule' to determine whether the HCC is breached (ie considering the cost of reinforcement at the voltage level at point of connection and the voltage level above)?
- **iv.** What are your views on the principles we have proposed to determine an appropriate HCC level for demand, including the potential for this to be set at a different level to generation under these principles?

Question 2b: What are your views on our proposals to maintain the requirement for three-phase connection requests to pay the full costs of reinforcement, in excess of Minimum Scheme (ie lowest overall capital cost)?

Question 2c:

- **i.** Do you agree with our proposals to maintain the current treatment of speculative connections and is there a need for further clarification on the definition of speculative connections?

ii. Do you agree that our wider connection boundary proposals broaden the disparity between connections deemed to be speculative versus non-speculative? If so, do you believe this needs to be addressed and how?

Question 2d: Do you consider that our proposed DUoS mitigations (a demand HCC, and retaining reinforcement payments for three phase and speculative connection contributions) present a cohesive package of protections for DUoS billpayers? Do you consider these proposals to interact in any way that could counter their effectiveness, and if so, how?

Question 2e: Do our updated proposals to treat storage in line with generation for the purposes of connection charging simplify charging arrangements for these sites and better align with the broader regulatory and legislative framework?

Question 2f: Do you agree with our proposals regarding the treatment of in-flight projects (ie that they should not be permitted to reset their connection agreement and retain their position in the queue), noting they retain the right to terminate and reapply from 1 April 2023 should they wish to be treated under the proposed connection charging boundary?

Question 2g: Do you agree with our proposals to retain the existing arrangements for managing interactive applications? Do you agree with our proposals on the treatment of unsuccessful applicants (that the connection charges at original application date will continue to apply if queue position is retained)?

Question 2h: Do you agree with continuing with the definition of the Minimum Scheme as currently set out in the CCCM? Do you believe this definition requires any further clarification or amendment, and if so, why?

Question 2i: Are there any risks associated with our proposals to allow current non-firm connected customers to seek a firm connection following the changes proposed by our SCR? Do you agree that existing non-firm connected customers that do seek a firm connection should be processed through existing queue management processes as determined by DNOs?

Question 2j: How necessary do you consider Ofgem intervention in Electricity Distribution Standard Licence Conditions 12, 15 and 15A? What duration might such measures be needed, or acceptable, following 1 April 2023? What value do you place on certainty of connection timeframes compared with time to connect?

Context

2.1. In our June 2021 consultation we set out our proposed changes to the current distribution connection charging boundary, which would:

- **Remove the contribution to reinforcement for demand connections** by introducing a 'shallow' connection charging boundary. This would involve connecting customers paying for extension assets only.
- **Reduce the contribution to reinforcement for generation connections** by introducing a 'shallower' connection charging boundary. This would involve connecting customer paying for extension assets and a contribution towards reinforcement at the voltage level at point of connection.

2.2. Under today's arrangements, both demand and generation must pay for extension assets plus a contribution to wider reinforcement at the voltage level at point of connection, and the voltage level above (a form of 'deep' connection charging).

2.3. We made our case for change on the basis that we consider the current connection charging arrangements may be holding back efforts to achieve net zero by failing to provide an effective signal to some connection customers, while presenting an up-front financial barrier to investment. We explained our thinking behind the different depths of charging for demand and generation; that in the absence of DUoS reform, generation users do not face any signal about the costs they put on to the system. This is because generation currently generally receives DUoS credits rather than charges, even in areas where it is driving costs.

2.4. We considered that our proposals would strike the right balance between maximising benefits such as removing barriers (particularly, for those where we think a behavioural response is unlikely), increasing fairness for connecting customers in constrained areas, and continuing to do so at least cost to consumers.

2.5. Since our June 2021 consultation, we have considered the issues raised and clarifications sought by respondents, as well as the further detailed recommendations of our Access SCR Delivery Group relating to implementation. While respondents' views in favour of purely shallow reinforcement charges were noted, we continue to stand by our proposals to retain some reinforcement charges for generation, on the grounds that they currently face fewer price signals than demand, and overall can be characterised by greater locational flexibility and behavioural responsiveness when compared to demand connections.

2.6. This section provides further detail on our proposed mitigations for the protection of DUoS customers from excessively high reinforcement costs from individual connections, from which they may not stand to benefit. We also set out our updated position on the treatment of storage under our proposed charging boundary changes.

2.7. In addition, we provide further information on how we propose our minded-to positions will interact with existing requirements (as largely set out in the Common Connection Charging Methodology)[12], as well as the Electricity (Connection Charges) Regulations 2017. This includes how we plan to mitigate the immediate effects of these changes on 1 April 2023, which remains our proposed implementation date.

2.8. The most significant progressions from our June consultation for the attention of stakeholders are as follows:

- We are proposing to introduce a High Cost Cap (HCC) for demand connections alongside our removal of reinforcement contributions. This is intended to protect DUoS customers from excessive contributions towards very high-cost individual connections in the absence of DUoS signals against such developments, while still delivering a shallow charging boundary for most demand connection customers.

- We are proposing that storage connections no longer treat import and export reinforcement separately, and that storage is considered in line with generation for the purpose of reinforcement contributions. This is intended to prevent the miscalculation of storage connection costs, or the unintended creation of distortive locational incentives specifically for storage.

2.9. These positions are a result of having further developed our thinking on the effects of our connection charge boundary on customer behaviour and addressing any unintended

[12] The CCCM is set out in Schedule 22 of the Distribution Connection and Use of System Agreement (DCUSA): https://www.dcusa.co.uk/dcusa-document/digital-dcusa-document/

consequences. Unless otherwise specified (in which case this consultation take precedent) the positions set out in our original consultation on our minded-to proposals continue to stand.

Summary of minded to consultation responses on connection charging boundary

2.10. The majority of responses to our connection charging boundary proposals were supportive (62%), though a large minority of respondents offered mixed views and raised a number of concerns (33%). A small minority of respondents did not support our proposals (5%).

2.11. The general move towards a shallower connection boundary received strong support. Respondents felt that the proposals represent a pragmatic set of changes in the near-term that would help to achieve net zero emissions targets. Many expressed positivity that the proposals were in alignment with a more strategic approach distribution network reinforcement, in contrast to their perception of the current more incremental connections-driven approach. Recurring themes in supportive responses were that our proposals have the potential to encourage DNOs to future-proof their networks and invest ahead of need.

2.12. The limited number of unsupportive responses focused principally on isolated issues unlikely to affect or apply to most customers, specific to their individual circumstances. Whilst network companies were broadly supportive of our proposals, one network company expressed a view that the current system is adequate and that any changes should be considered for implementation alongside the conclusions of a wider DUoS review.

2.13. Many respondents raised potential risks of the effectiveness of the existing High Cost Cap (HCC) for generation if it was not amended, with many specifying that it may need to include demand. Some stakeholders in remote areas set out a view that the proposals would not lead to significant differences from the current arrangements given the already high cost of network in some areas. There were a small number of stakeholders who put forward a view that locational signals under the new arrangements may provide insufficient economic signal.

2.14. Various responses stated that the full impact of these proposals is difficult to predict without further clarity regarding future charging arrangements. Respondents also felt that the language in the proposals was too technical, which may not transfer well to those outside the energy industry and thus not be as transparent as possible. There were also numerous calls for grandfathering of existing arrangements to be considered to minimise disruption.

2.15. Views and suggestions shared on key and recurring topics are set out below.

Removing the contribution to reinforcement for demand connections and reducing it for generation

2.16. We asked respondents whether they agree with our proposals to remove the contribution to reinforcement for demand connections and reduce it for generation. Furthermore, we asked whether there are any arguments for going further for generation under the current DUoS arrangements.

2.17. The majority of respondents to this question (35) offered strong support for our proposals to remove the contribution to reinforcement for demand connections and to reduce it for generation. A dozen respondents expressed that any reductions in generation connection charges should be introduced alongside new DUoS arrangements and that further information on the DUoS reform was needed.

2.18. A small number of respondents (seven) raised concerns that the proposal to reduce generators' contribution to reinforcement could distort generation investment decisions by reducing their locational signals and were not well justified.

2.19. Nine respondents disagreed with our proposal in that the reinforcement contribution should be similar for demand and generation. They felt that the proposal should go further and introduce a shallow boundary for all and remove contributions to reinforcement for generation sites as well. This was to create a level playing field across all network levels and have consistency with demand and transmission.

2.20. Some responses, while overall supportive, expressed the need to apply a charge to deter unrealistic applications, or requested the use of some other form of user commitment methodology or alternative protections to ensure stranded assets are minimised.

2.21. Four responses were overall of the view that the proposal would help to remove barriers to the roll-out of low carbon technologies and would support GB's net zero targets. There was a general theme amongst some respondents that the proposals would benefit from further clarity and detail. Due to this, some respondents felt they could not provide a sufficient response to the consultation in all areas.

2.22. A small number of respondents (two) highlighted the need for grandfathering arrangements to protect existing connectees from risk of double-charging, and this view was repeated in their responses to several questions.

2.23. In terms of technology specific comments, three respondents felt that only heat pumps and electric vehicles ('EVs') should receive exemptions from reinforcement costs to drive take-up of low carbon technologies, rather than a blanket exception for all demand, which may include high carbon users. One respondent cautioned against the treatment of storage operators similarly to generators as they can improve system-wide flexibility and reduce the need for network reinforcement. They reasoned that storage does not generate energy, and it therefore seemed contradictory to charge energy exported as though it was newly generated.

Effectiveness of the current connection charging arrangements in sending a signal to users

2.24. We asked respondents for evidence on the effectiveness of the current connection charging arrangements in sending a signal to users. We further asked what respondents thought would be the effect of our proposed changes and whether this would vary between demand and generation connections.

2.25. A large number of responses mentioned that current arrangements create a disincentive to connect in some areas that could present a barrier to investment in low carbon technologies and delay the electrification of heat and transport that is needed to achieve GB's net zero targets. Several respondents described examples of projects that had not been able to proceed under the current arrangements where connection costs were prohibitive.

2.26. One respondent described the current arrangements as part of 'an obsolete electricity network architecture' leading to a location lottery based on connection site availability. They felt the proposal would help to resolve this issue by enabling more flexibility as well as shift certain responsibilities for economic investment from developers to DNOs who are in a better position to manage network constraints. The respondent felt that, as a result of these proposals, DNOs would be expected and incentivised to invest in anticipation of wider network needs, rather than taking an incremental and reactive approach. In connection with this view, several respondents provided evidence showing that shallow connection charges can still deliver a reasonable signal.

2.27. One respondent summarised that the current distribution connection charging arrangements are sending such strong signals that some sites for renewable and storage projects are only economic if the grid is available without reinforcement and connection charges are low. The proposal would make the development of such sites economic, and potentially bring forward additional renewable and storage capacity.

2.28. Presenting an opposing view, five respondents supported the current connection boundary arrangements. They put forward the view that locational cost signals are working well and already require customers to pay the share of costs they impose on the network. These respondents saw it as beneficial that current arrangements often lead to customers to seek alternative connection options, which may reduce connection charges and facilitate more efficient network development. Some respondents therefore expressed opposition to the proposals. They argued that moving to shallower charges would socialise more costs and create a risk of costly connections being subsidised for the connecting party by consumers.

2.29. One distribution network owner respondent expressed that the difference in acceptance rates between offers with and without reinforcement was less than 10%, however they also outlined that 75% of their connectees expressed a view that the current arrangements had an impact on the capacity they requested. Another network respondent echoed this, stating that their engagement with customers on the costs of connection reduces the volume of connection enquiries that proceed to the offer stage in the first place. They put forward a view that our proposals will lead to flexible or curtailed connections becoming more established as temporary rather than enduring solutions for many network users.

2.30. Several respondents expressed that it was difficult to anticipate the full impact of the proposals without considering the future changes to DUoS, and that any changes for generation should be implemented alongside DUoS reform to avoid any new generation connecting in locations that increase costs for DNOs and could increase future DUoS charges for existing generators. Some respondents also expressed a general disagreement that wider DUoS billpayers should subsidise reinforcement to a greater extent.

2.31. One respondent felt that the proposals remove some distortions but replace them with others, which could encourage projects requiring reinforcement to locate at higher voltage levels where they can maximise the benefit of not having to pay for costly reinforcement under the proposals.

2.32. Several respondents also raised that demand and generation (particularly small-scale community generators) as well as storage (particularly pumped) are locationally inelastic and that the methodology should not assume that connectees could easily relocate. Particularly for renewables such as hydro, location is influenced by rainfall and topography. Generally, community generation projects are unable to respond to connection pricing signals and reduced connection costs may potentially remove this barrier.

2.33. Some respondents expressed the view that community generation companies may therefore require a different set of rules from the current charging arrangements to ensure fair connection opportunities. Locational inflexibility and unfairness were also stressed by several respondents who raised the issue of perceived unfair treatment of islands in Scotland needing to pay higher costs for an interconnector in comparison to EU/Ireland locations.

Effectiveness of the current arrangements in facilitating the efficient development and investment in distribution networks

2.34. We asked respondents about their views on the effectiveness of the current arrangements in facilitating the efficient development and investment in distribution networks and how this might change under our proposals.

2.35. Respondents were largely critical of current arrangements, with some twenty responses expressing that the current system is seen to be ineffective and inefficient, does not allow DNOs to plan for increased generation or demand and thus leads to a piecemeal approach to reinforcement while not supporting the level of connections needed for net zero.

2.36. A further 16 respondents felt that the proposal would result in a more efficient development of networks since DNOs will be able to plan networks in a more strategic and coordinated way. The proposal also received support as it is seen to encourage other approaches to network reinforcement, such as flexibility procurement and alternative technologies or business models which could help to enable a net zero transition at least cost.

2.37. A few respondents (four) felt that the current arrangements already ensure efficient and relatively timely investment overall, albeit sometimes with delays, and that they provide an effective locational cost signal. There were also concerns about if and how DNOs could fund the proposed changes.

2.38. Several responses expressed a view that the impact of the proposal on more strategic planning would be limited, and that RIIO-ED2 decision were expected to have a greater impact.

2.39. Some respondents were concerned that under the new proposals DNOs could default to building more capacity rather than exploring other options under shallower connection boundaries or that prospective connectees might submit speculative applications or applications with excessive capacity requirement which might be avoided if a financial commitment was required.

2.40. Several respondents (four) inquired how more strategic investment would be assessed and requested further information on this, while one respondent would like to see further assurances that decisions on network development are ultimately overseen by the regulator.

2.41. A small number of respondents (two) felt unable to provide feedback on the proposal but did not provide further explanation or detail as to why.

The need to provide connection customers with more certainty may reduce the potential for capacity to be provided through other means such as flexibility procurement

2.42. We asked respondents if they agreed that the need to provide connectees with certainty of cost reduces the potential for capacity to be provided through other means, such as flexibility procurement, and how this might change under our proposals.

2.43. Some respondents supported the hypothesis but expressed that flexibility and certainty of price are not necessarily incompatible. Others stated that it was too early to tell whether alternatives to reinforcement would gain traction and whether a lack of guaranteed price is a significant barrier to this. Further respondents felt that the proposal risks a large increase in reinforcement and that, as a result, it could take applicants longer to secure a connection.

2.44. There was a strong sense of agreement in the responses that prices need to be reflective of costs, however, there must also be sufficient certainty of price and revenue availability (ten responses, particularly from developers). Price certainty is critical for investment as it can reduce the cost of delivery and therefore consumer bills. Arrangements that pose undue risk to support flexibility were seen as likely to be less effective.

2.45. Some stakeholders raised that flexibility procurement arrangements are not yet sufficiently well-defined and certain for banks to provide potentially necessary loans. This was seen as a complicating factor relating to the risk of return on investment that may inhibit renewable generation.

2.46. Some respondents expressed disagreement about uncertainty of price reducing the potential for capacity to be provided by other means such as flexibility procurement, with some stating that investors don't need price certainty but are too used to having it.

2.47. One respondent felt that flexible connections should only ever be a temporary arrangement, while another respondent viewed their principal function as being to reduce the waiting period for a connection.

High Cost Cap ('HCC') - the 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

2.48. We asked respondents whether the HCC should be retained and whether there is a case to review its interaction with the voltage rule if customers no longer contribute to reinforcement at the voltage level above the point of connection. Responses to these questions were mixed, but a majority supported retaining the HCC (20 responses) while some responses supported the removal of the HCC (eight responses). The remaining respondents expressed no preference, but a need for its review (seven responses).

2.49. Most responses supported keeping the HCC to protect against too much of an incentive, or lack of disincentive, for generation to connect at any location regardless of cost. For example, generation connected in remote or less densely populated areas could drive very high reinforcement costs. A key argument to retain the HCC articulated by stakeholders was to protect DUoS billpayers from large cost increases and an unfair additional DUoS cost burden from connections-driven reinforcement work. Many expressed that it would be reasonable to fund more through DUoS customers if they were likely to benefit from the increased capacity created by this reinforcement, and their contributions were not excessive.

2.50. There were several responses that did not support retaining a HCC. They suggested that spreading the cost of all connections across all network users would be fairer than continuing to require individual projects to pay for reinforcement. Some of these respondents expressed opposition to retaining the HCC for the connection voltage plus the voltage level above on the basis that this would undermine the effect of moving to shallower charges.

2.51. The removal of the HCC for generation was something that one stakeholder felt may help to increase local generation from renewables and storage projects, and that the absence of an HCC for demand may also help to support the uptake of EVs and heat pumps. One respondent outlined their view that the current HCC disincentivises investment in new large-scale projects in constrained areas, resulting in a lack of network upgrades and so hindering progress to net zero.

2.52. While some supporters of the existing generation HCC see it as a blunt tool in need of review, two responses advocated for the HCC to be applied to the voltage level above the connection level and increased for 33kV in the north of Scotland specifically, as 33kv networks in the north of Scotland were noted to be particularly constrained and frequently reinforcement is required for new connections.

2.53. Another response advocated that the HCC should apply only to the same voltage level at which customers are connected since, if triggered, the HCC is a sign of a lack of strategic planning from the DNOs. There were also views that support retaining the HCC for generation, while proposing that a cap be introduced for demand for reinforcement up to one voltage level above the point of connection.

2.54. While several respondents did not offer a preference for or against retaining the HCC, they agreed with the need for a review of its interaction with the voltage rule and assessment of potential impacts of its removal, as any benefits of moving to a shallow connection boundary could be negated by an unchanged HCC. One response questioned how often the HCC is currently triggered and requested an assessment of how often it would be triggered under the changed charging boundary. If this demonstrated that the additional protection is redundant, it could potentially be removed. It was recommended to review and reassess the requirement of the HCC at a reasonable time after introducing the proposals.

2.55. Other responses expressed that the HCC should act as a trigger for assessment of the case for strategic investment and broader network optimisation options, or that more effective DUoS locational signals could replace the HCC entirely in the longer term. It was further suggested in one response that Ofgem should take account of whether projects captured by the HCC support the delivery of net zero, in which case they could contribute based on their affordability and viability, rather than a one-size-fits-all solution using a fixed £/kW threshold. This was echoed by another response which stated that it should be revisited whether £200/kW remains the appropriate threshold.

2.56. Stakeholder views were mixed on the specifics of calculating any HCC. Some supported the continued use of reinforcement costs at two voltage levels, however, others argued that this would undermine the move to shallower charges. A small number of respondents proposed raising the cap for specific voltages and regions, allowing for projects to avoid hitting the cap in more constrained areas. A few stakeholders suggested that reinforcement at voltages above the point of connection should trigger a strategic investment assessment by the DNO rather than an automatic cost increase for the connecting customer.

Recovery of the costs associated with transmission that are triggered by a distribution connection

2.57. We requested views on the recovery of the costs associated with transmission that are triggered by a distribution connection and whether these need to be considered alongside wider charging reforms or whether a change could be made independently.

2.58. A large number of respondents (14) felt that these costs must be part of a wider TNUoS reform and changes should not be made independently. There was a sense of general support for the ability for networks to recover costs in the responses. A further 11 views supported that these should be considered alongside wider charging reforms and that transmission reinforcement costs should be socialised.

2.59. Eight responses pointed out that the costs associated with transmission reinforcement triggered by a distribution connection should be considered a distortion that still needs to be addressed.

2.60. Others expressed that the socialisation of transmission costs where those relate to a distribution connection should be considered a priority, and that this should be progressed independently as a separate modification (two). A small number of responses suggested that these costs should be recovered through use of system charges (two).

2.61. One respondent noted that connection charges relating to transmission reinforcement may fall outside the scope of provisions set out in sections 16 to 23 of the Electricity Act 1989 ("the Act"), which relate only to costs incurred by the distributor.

2.62. Eleven respondents expressed concerns that Scottish connectees may be in a disadvantaged position because of the different definition of voltage boundary between transmission and distribution when they trigger 132kV reinforcement.

2.63. There were further concerns that more information is needed to understand the extent to which distribution-level users use the transmission system and what charging methodology may be applied.

2.64. One respondent supported maintaining the current charging approach and one other respondent disagreed with the premise of the question, as they felt that the SCR should relate only to price signals and not to cost recovery.

Likelihood of inefficient investment under our proposals and introduction of liabilities and securities to mitigate this risk

2.65. We asked respondents about their views on the likelihood of inefficient investment under our proposals (eg an increase in project cancellations after some investment has been made) and whether there are good arguments for further considering introducing liabilities and securities to mitigate this risk.

2.66. Seven respondents felt that the risks of inefficient investments are minimal. This was seen in the context of a growing economy and a growing demand for electricity, where alternative users will never be far away.

2.67. Some respondents (six) felt that while there is a risk of inefficient investment through our proposals, this would be outweighed by the ability of DNOs to manage investments more efficiently and expedite net zero.

2.68. Four respondents did not believe that the proposals would lead to an increase in project cancellations or stranded assets after some investment had been made, given that the current system requires developers to pay higher connection charges upfront than the minded to proposal.

2.69. It was also expressed that the risk of not future proofing the network outweighs the risk of stranded assets. Even if that risk materialised, several respondents (five) believed that any stranded assets could be repurposed.

2.70. A few respondents (three) were concerned that the proposals would make inefficient investments more likely to progress, especially for demand but that a banded contribution to reinforcement could provide some certainty and signal.

2.71. Many respondents (12) expressed that liability and securities are very complex and should not be introduced to small distributed generators or that a proportionate or reduced contribution for both should be kept. There was a concern that liabilities and securities are a particularly notable issue for community generators.

2.72. On the other hand, several respondents believed that without any form of securitisation there is a significant risk of stranded reinforcement on both the transmission and distribution systems. Therefore, reasonable liabilities and securities could be placed on the customer in the event that they cancel or delay their project (nine responses). Specifically, at transmission level, securities received support from two respondents.

2.73. There were also concerns that customers might oversize their capacity requests as a consequence of the proposal. A proposed mitigation for this was a capacity charge, fixed for five years.

Interactions between our connection reforms and the Electricity Connection Charges Regulations 2017 ('the ECCR')

2.74. We asked in our minded to positions consultation whether the interactions between our connection reforms and the ECCR must be resolved before we are able to implement our proposed reforms, and how the effects of the ECCR (if at all) should be factored into decision making, given the levels of uncertainty around subsequent connectee(s).

2.75. A few respondents (five) felt that the ECCR is essentially unnecessary. One stated it should be replaced by a regime whereby second and subsequent connectors pay a pro rata portion of the connection cost amortised over a long period (say 30 years) according to the amount of use based on MWh. Several respondents stated that the ECCR had never factored in their decision making and that the proposed connection charging changes should not be delayed by an ECCR review or reform. The ECCR were understood to be triggered very infrequently and applied on a case-by-case basis by these stakeholders.

2.76. A few respondents (three) stated that the ECCR will need to remain in place until a replacement solution has been set up. One respondent was concerned with the need for clarity in this area, as some developments may have expected as part of their business case that any up-front investment would be partially recovered in future via the ECCR as other network users connect. They similarly expressed a need for more clarity on how any future 'second comers' under the ECCR might contribute to prior network upgrade costs, whilst avoiding any double-counting.

2.77. A small number of respondents (eight) expressed that the ECCR needed to be reviewed to align with the Common Connection Charging Methodology (CCCM). Some specifically mentioned that any conflict between the charging reform and the ECCR would need to be resolved before the implementation of these reforms given the ECCR is set out in legislation.

2.78. A small number of respondents expressed (eight) that, especially for historic network extension schemes, connectees should receive any reimbursement under the ECCR for a period of up to ten years or not limited by time at all under grandfathered arrangements.

2.79. A small number of respondents (two) felt that no changes are required to the provisions in the ECCR relating to sole use assets and second comers, as the treatment of extension assets is largely unaffected by the proposals.

2.80. Respondents generally regarded that the most effective way to establish how the ECCR should interact with connection reforms is through legislative changes, but it was recognised that this would have to be delivered within the implementation timescales. Some respondents supported the proposal to explore an alternative viable solution that could be utilised either as an interim measure while legislation is changed, or until a more enduring solution emerges. Some interim solutions had already been developed with DNOs, while other organisations are also exploring interim measures. They articulated that changes should not be retrospective so as not to undermine project developments already underway.

Updates to our minded to positions

2.81. We have provided further detail on our minded to positions to address some of the questions raised in responses to the consultation. We sought the support of our Delivery group in the form of recommendations to inform the clarifications we set out below.[13]

DUoS mitigations: the High Cost Cap

2.82. In our June consultation we set out our views on how the interaction between the voltage rule and generation HCC could operate under our proposed charging boundary reforms. In addition to those proposals, we have developed our DUoS mitigations to include an additional proposal to introduce an HCC for demand connections, alongside clarifications of how the existing HCC for generation would apply under our proposals.

2.83. The voltage rule currently determines the reinforcement costs that generation connections are required to contribute to, as well as the costs that are factored into calculation of whether the HCC has been exceeded. These costs are based on reinforcement required at the voltage level at point of connection plus one voltage above. All generation connections are currently required to contribute towards reinforcement at these voltage levels, at a cost determined by the Cost Apportionment Factors (CAFs). If reinforcement costs exceed the HCC, the customer is required to pay 100% of the costs that exceed the cap.[14] The existing HCC for generators ensures that DUoS billpayers are protected from contributing towards high cost developments (whatever is not funded by the CAF), whilst the connectee can still fund the connection in full above the HCC threshold if they still wish to connect.

2.84. We sought views on the continued need for a generation HCC. The majority of respondents supported its retention but felt it would be reasonable to fund more of the cost through DUoS customers if they were likely to benefit from network capacity created by reinforcement. Some respondents proposed the introduction of a similar mechanism for

---

[13] Details on the role and membership of the Access SCR Delivery Group are set out in our original SCR launch statement: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision

[14] The details of the current arrangements and our proposals for the voltage rule, High Cost Cap and CAFs were set out in Appendix 1 of our June 2021 consultation: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

demand connections. Other supportive comments considered that better locational pricing signals achieved through DUoS reform could supersede the need for any HCC.

2.85. Unsupportive responses viewed the HCC to be contrary to the move to shallower charges and that disincentivising generation connections in constrained areas may slow progress towards net zero. Others expressed no preference, but a need for review of the cap.

2.86. Our minded-to position continues to be that the generation HCC prevents excessively high costs from being socialised (per the existing DUoS methodology) across the wider DUoS customer base who are unlikely to stand to benefit from any individual investment but may benefit from reinforcement in aggregate.

2.87. While DNOs advise that this is rarely triggered, we are informed that its existence serves as a useful tool in early discussions with potential connectees in keeping connection costs within the bounds of a set cost per kW. The DNOs have advised that they do receive connection enquiries that would exceed the HCC where, as a direct result of early enquiries, the customer chooses not to proceed to the formal offer stage. These projects are therefore not captured in formal connection offer data, making it difficult to establish how many projects do not go ahead due to the existing HCC.

2.88. In addition, our proposals to move to a purely shallow connection boundary for demand connections, in lieu of DUoS mitigations, would provide no disincentive against high-cost developments that may not be in the interests of the wider customer base that would be required to pay for their reinforcement. A number of stakeholder responses to our core charging boundary proposals raised the risks presented by undertaking this cost transfer without mitigation. We are therefore additionally proposing the introduction of a demand HCC in the absence of DUoS signals against such high-cost developments, and we are seeking your views on this (**see question 2a.i**).

2.89. We propose that introducing a demand HCC at an appropriate threshold can strike a balance between achieving the benefits outlined in our original proposals, whilst ensuring that DUoS bill payers are protected from having to pay for excessively expensive connections. Without mitigation, such as a demand HCC, there would be limited incentive for connectees to avoid particularly high cost areas and/or request capacity in excess of their needs, which would have to be funded by DUoS billpayers. Given the differences in the depth of the connection charge and the characteristics of how generation and demand use the network, it may be appropriate to consider different thresholds to enable a level playing field.

2.90. We provide further details below on how we propose a cap might be set, and we are seeking your views on the necessity of retaining a cap for generation connections and introducing a cap for demand connections to help protect DUoS bill payers (**see question 2a.ii**).

2.91. As outlined in 1.18, note that along with the other DUoS mitigations specified in this consultation, the specific threshold for any cap is an area we consider continues to fall within the scope that we set out in our DUoS SCR consultation, enabling any arrangements to be kept under review alongside any future DUoS reform proposals.

Costs factored into the HCC

2.92. We sought stakeholder views in our previous consultation on what reinforcement costs should contribute towards the HCC. This could include using only reinforcement costs at the voltage level of the point of connection or retaining the existing two voltage level calculation. We consider that the first of these options would significantly dampen the disincentive the HCC creates to connect in areas where reinforcement costs are high. This could lead to excessive additional costs for DUoS bill payers as a consequence of expensive reinforcement from which the connectee is likely to be the principal beneficiary. This option may be more desirable in future if DUoS charges can more accurately signal high-cost areas. Given we expect no changes to the DUoS methodology under this SCR by 1 April 2023, we are minded to retain the calculation of the HCC using two voltage levels (the voltage level at point of connection, plus the one above). As noted in section 1.21, we outline our view that any DUoS mitigations would be retained within the scope of a future DUoS SCR, which would present further opportunity to review this proposal when DUoS reform proposals are clear.

2.93. Our Delivery Group's leading recommendation was that reinforcement at all voltages should be factored into the calculation of the HCC, which would fully capture the cost of upstream reinforcement at higher voltage levels.

2.94. As stated in our June consultation, we are not considering whether the HCC should apply at all voltages, as this would effectively be a deeper connection charge than is faced today. Any reinforcement at the point of connection and the voltage level above is already fully funded by the DNO, regardless of whether the cap has been reached. This reflects that reinforcement at these levels is likely to provide a shared benefit to a wider group of users.

2.95. We therefore propose that the two voltage levels (at point of connection and the one above) continue to be used in the calculation of the HCC. We do not consider this to be contrary to shallower connection charges, as connecting customers will still face reduced reinforcement charges versus status quo arrangements, regardless of whether they hit the cap, because of our proposed voltage rule amendments. We are seeking your views on this proposal (**see question 2a.iii**).

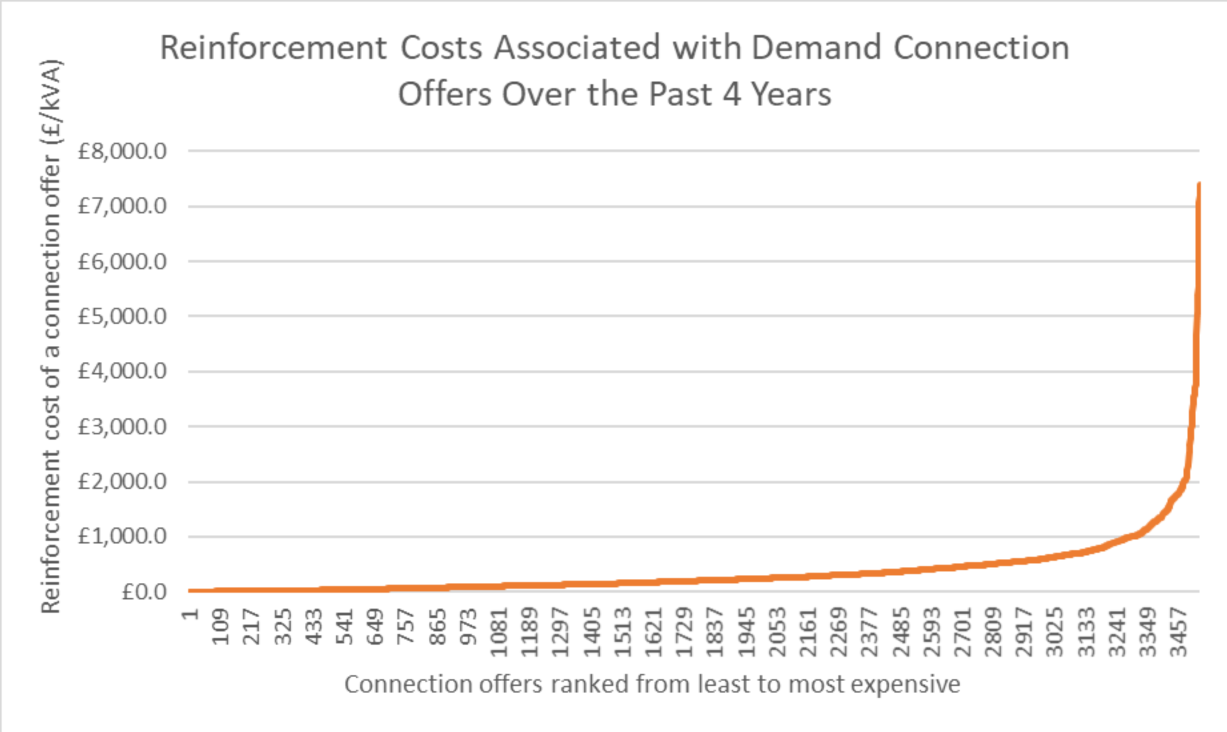
Setting the HCC

2.96. We asked our Delivery Group to form a view on how a demand HCC might be set. The group provided us with their recommendations alongside data from DNOs on reinforcement costs arising from demand connection offers over the course of RIIO-ED1.

2.97. Figure 1 shows the reinforcement cost associated with connection offers made by one DNO to demand connecting customers over the past 4 years. The plot ranks connection offers from lowest to highest (reinforcement) expense in £/kVA on the x-axis, against their cost on the y-axis.

2.98. This profile of reinforcement costs, where there are a small number of projects where reinforcement is significantly more expensive, is consistent across all DNO regions. DNO connection data suggests that most connection requests trigger relatively consistent reinforcement costs, up to approximately £1000/kVA. However, there are a small minority of connection offers which are very expensive and can trigger reinforcement costs that are significantly higher.

Figure 1 – Distribution network reinforcement costs (all voltage levels) for demand connection offers issued over the past 4 years



2.99. Currently, the reinforcement costs for more expensive connections (on a £/kVA basis, rather than absolute cost) would be apportioned between the connecting customer and DUoS billpayers via the CAF. Under our proposed shallow connection boundary, if there were no additional mitigations, all this reinforcement would be charged to DUoS billpayers. There would also be no financial disincentive to the connecting customer to accept an offer with very high reinforcement costs. This could lead to an additional magnification of the effect we currently see at the right hand side of the reinforcement cost profile in Figure 1. It is our belief that DUoS billpayers need to be protected against being required to fund projects with a very large associated reinforcement cost, as it is not clear that this would be to their benefit.

2.100. The data provided was reflective of the overall reinforcement cost per connection, quoted on a £/kVA basis. For this reason, it was not possible to calculate a demand HCC using only the voltage at point of connection plus one, as we propose. We also note the discrepancy between the existing generation cap which is on a £/kW basis, and the demand connection data provided to us by the DNOs on a £/kVA basis, which we will seek to understand and address the matter of consistency in our final direction.

2.101. We recognise the limitations of an HCC as a relatively blunt, but historically effective mechanism (in the case of generation) to protect DUoS billpayers from excessive costs. We therefore do not propose that the HCC should be set at a threshold that would be routinely triggered (based on recent connections data), instead triggering only for a small minority of high-cost projects in line with the frequency of use for the current generation cap.

2.102. Our proposals therefore seek your views on the principle that the demand HCC should be set at a threshold (such as the 95th percentile of connection offers on a £/kVA basis) which would act as a reasonable protection against the highest cost projects only. From the data provided to us, targeting a threshold at the 95th percentile of ED1 demand connections would result in a cap on total reinforcement costs of circa £1,400/kVA.

2.103. As we do not have the data only for two voltage levels only (ie the voltage at the point of connection plus the one above), it is unlikely that the cap will be set at this specific level for our final decision (£1400/kVA refers to total reinforcement costs). This is illustrative of the principles we would apply to protect DUoS customers from excessive reinforcement costs arising directly from the proposed shallower charging boundaries (**see question 2a.iv**)

2.104. While equivalent data relating to generation connections has not been assessed as part of this work, we are mindful that such data may not be the best means by which to review the cap in future due to distortions created in the data created by the existing HCC. We consider that a lasting discrepancy between the cap established at demand and generation is something that would require further assessment. We are therefore minded to introduce a cap for demand as part of our final direction, at a threshold that will be kept under review alongside the existing generation cap as part of our ongoing DUoS reforms.

2.105. Given the close linkages between this area and the possible impacts of future DUoS reforms on the efficacy and/or need for the HCC as proposed in this consultation, this is an area that we propose to keep under review through our wider DUoS reform programme.[15] As such, we believe it would be reasonable to proceed to implement a cap based on these

[15] On 1 November 2021 we released a consultation on our proposals to descope the wide-ranging review of Distribution Use of System charges from the current Access SCR and take it forward under a dedicated SCR with a revised timescale: https://www.ofgem.gov.uk/sites/default/files/2021-10/Consultation%20on%20next%20steps%20for%20DUoS%20reform.pdf

principles as part of our final direction, to be kept under review within the scope of future DUoS reform work as set out at 1.18.

DUoS mitigations: three-phase connections

2.106. Some respondents sought clarity on the treatment of three-phase connection requests, or requests for a supply voltage that is not deemed necessary to meet the requested capacity, after the introduction of our proposed changes. Under the current charging methodology, such a connection is charged for the full cost of the reinforcement in excess of the Minimum Scheme. These projects are typically large, costly developments which involve a significant amount of fixed cost to upgrade the local distribution network, but it is still possible that they may not trigger the proposed HCC for demand.

2.107. We have considered several options for the treatment of three-phase connections under the new charging boundaries. These options included reducing reinforcement charges for three-phase connections in line with the wider changes proposed. Where the HCC was triggered, DUoS protections would be in place.

2.108. We also considered amending the clause to explicitly introduce a DNO review as to whether an increase in phases or voltage might have a benefit to the wider customer base in the area, which might reduce their individual contribution to reinforcement costs. This method would require criteria and an evaluation process to be introduced, as well as introducing potential complications and room for challenge with regards to reasonable cost apportionment and what classifies as wider benefit.

2.109. We propose that the existing arrangements should remain in place, requiring that customers requesting a three-phase connection continue to pay the additional cost of converting the local distribution network to the requested number of phases and/or voltage. Our rationale is that connection requests of this kind could be considered to sit outside of the mitigations provided by the Minimum Scheme, therefore keeping additional costs assigned to the connecting customer may protect DUoS billpayers from connections where they risk being excessive.

2.110. The proposed approach arguably retains a stronger disincentive for three-phase connection requests compared with connections calculated purely under the Minimum Scheme, where reinforcement costs will be absorbed by DUoS up to the HCC. However, we believe our proposed approach will prevent gold-plating in response to our changes including attempts to secure capacity ahead of need, or without a clearly establish need. Without such a mitigation, there would be limited disincentive for all users to request a three-phase supply.

2.111. It is our view that the network companies should continue to ensure that strategic upgrades to three-phase network are principally delivered through their network development plans under the RIIO-ED2 framework. We believe this to be a more targeted and strategic approach that enables upgrades can be prioritised, in contrast to a connections-led approach which would be more iterative and less targeted as a single three-phase connection request could potentially trigger widescale network investment regardless of the broader requirement for this capacity.

2.112. We welcome your views on this proposed treatment (**see question 2b**).

DUoS mitigations: speculative developments

2.113. Additional detail was sought on the treatment of speculative developments under our proposed changes to charging arrangements. The characteristics of developments that may be considered as speculative are set out in in the Common Connection Charging Methodology.[16] These include developments where:

- their detailed electrical load requirements are not known
- the development is phased over a period of time and the timing of the phases is unclear
- the capacity requested caters for future expansion rather than the immediate requirements of (an) end user(s)
- the capacity requested caters for future speculative phases of a development rather than the initial phase(s) of the development
- the infrastructure only is being provided, with no connections for end users requested

[16]As defined in DCUSA version 13.7, paragraph 1.39. of Schedule 22 – Common Connection Charging Methodology

2.114. Under the current arrangements, if a customer requests a connection for a speculative development, they are liable for all reinforcement costs (ie not just those that would be apportioned under the 'voltage rule'), in addition to any ongoing operational and maintenance costs. Given that under our shallower charging proposals connecting customers may not be liable for any reinforcement costs, we have been considering whether amendments to the treatment of speculative developments would be appropriate to avoid exacerbating the cost differentiation between contributions for speculative and non-speculative developments.

2.115. In our June consultation we sought views on whether new obligations on connecting customers may help mitigate the risk of inefficient investment arising from speculative developments over-specifying their requirements in attempt to secure capacity ahead of need. There were mixed responses from stakeholders, with some believing risk to be small, and others suggesting that banded contributions to reinforcement would be sufficient mitigation, at least in the case of generation connections. Still others suggested that the risk of not future-proofing the network exceeded that of stranded assets, with reasonable scope for use of any such assets in future.

2.116. We asked the Delivery Group for their recommendation on speculative connections and were provided with a range of scenarios with two leading propositions, both of which included a recommendation to review the definitions of speculative developments under the CCCM to provide further clarity.

2.117. The first proposal was to make no change to the existing arrangements, which would retain the existing principles and limit the risk of the DNO having to provide capacity where confidence in its ultimate utilisation is low. Considering our proposed changes to the voltage rule for non-speculative developments, this would result in a greater cost difference between a development determined to be speculative compared to non-speculative developments.

2.118. The group's second proposal was to require speculative developments to pay all reinforcement costs, but only for reinforcement triggered at voltages above the point of connection. This was suggested as a means by which to reduce but retain the reinforcement price signal for speculative developments, thereby lessening DUoS billpayer risk exposure. A downside of this approach may be opportunities for gaming through methods such as successive connection applications at low capacities to avoid triggering reinforcement costs above the point of connection.

2.119. Another outstanding question on this approach is the appropriate point at which to levy reinforcement costs, as reinforcement at higher voltages is often more costly, and so the reinforcement price signal may not be lowered significantly.

2.120. We are minded to retain the current arrangements for speculative developments, subject to a review of the CCCM definitions regarding developments that fall into this category (as set out in 2.113). We consider that the protection of DUoS customers from higher risk projects should be retained, but with the expectation that more precise examples of high-risk development types and the role of strategic network development in reducing the risk of asset stranding, should be considered in the review of CCCM definitions. We seek your views on this position under **question 2c**.

2.121. Considering the three proposed DUoS mitigations set out in this consultation, we are interested more broadly in stakeholders' views as to the coverage they provide to protect DUoS billpayers as a package. We seek your views on their effectiveness and potential interactions in **question 2d**.

2.122. As outlined in 1.18, along with the other DUoS mitigations outlined in this consultation, we consider that all the DUoS mitigations we have outlined continue to fall within the scope proposal recently set out in our DUoS SCR consultation. This will enable these arrangements to be reviewed alongside any future DUoS reform proposals whilst enabling nearer term implementation and realisation of benefits.

The treatment of storage

2.123. In June, we set out our minded to position that no change was expected to the treatment of storage. Storage is considered generation under the Electricity Act and, for the purposes of calculating connection charges for storage, import and export are assessed separately. The drivers of reinforcement determine treatment under connection cost apportionment.

2.124. Responses to our June consultation sought clarity on the treatment of connections when reinforcement is needed for both demand and generation. Clarity was further requested in this area due to the proposed levels of reinforcement contribution for demand and generation connecting customers, both of which can currently apply to storage depending on the driver of reinforcement.

2.125. The treatment of storage connections under both demand and generation cost allocations creates a number of complications. One such challenge raised by our Delivery Group is that it is not always clear whether import or export drive the significant reinforcement needed at time of connection. It can therefore be difficult to determine which reinforcement contributions apply. This risks incorrectly calculating reinforcement charges and could introduce vastly different connection charges for storage depending on the characteristics of the local network, far in excess of those that might be faced under a single reinforcement charge calculation.

2.126. Much storage has high locational flexibility compared to other types of generation and demand, which we consider means that it should be encouraged to locate where it does not increase costs unnecessarily where possible to do so. However, we are also conscious that maintaining dual charging treatment under our proposed reforms could lead to perverse incentives for storage to connect where import reinforcement exceeds that of export. This could inadvertently result in a locational price signal exclusively faced by storage, which may drive storage towards demand constrained areas. Such a narrowly targeted signal is not the intention of our current proposals and may preclude consideration of more holistic changes to locational signals as part of future DUoS reform.

2.127. As storage grows and distribution system operation further develops, it may become increasingly desirable for other types of generation to co-locate storage assets. Having a single, consistent reinforcement charge could prevent a perverse incentive to separately host storage assets where the connection can benefit from demand reinforcement categorisation.

2.128. We are therefore minded to treat storage as generation for the purpose of connection charges following the introduction of our proposed reforms, which we believe to be more consistent with the broader regulatory and legislative framework. This would mean that storage connections are required to contribute to reinforcement works at their connection voltage according to their export capability and would not be exempted from reinforcement contributions if their import reinforcement works take precedence. This proposed arrangement is still shallower than current arrangements and would avoid the potential for vast variation in storage connection charges due to complicated reinforcement calculations.

2.129. This is a change from our June consultation position, resulting from stakeholder contributions and policy development with the support of the Delivery Group recommendation. We consider the risks to be clear and the amendment necessary to avoid unintended consequences of our charging proposals and risks of unfair treatment for different types of network user, while ensuring we do not hamper forthcoming DUoS developments.

2.130. We seek your views on our updated position under **question 2e**.

Required changes to the Electricity (Connection Charges) Regulations 2017 (ECCR)

2.131. In our June consultation, we set out our view that we expect the ECCR, that require DNOs to arrange for payments from second comers to first comers, will continue to apply in the case of extension assets. Our view continues to be that the ECCR with regards to extension assets will not be affected by our proposals. However, our proposed removal and reduction of reinforcement charges raises the question as to whether DNOs would ever recover such contributions from second comers connecting after the charging reforms.

2.132. We also highlighted that amending the ECCR is the responsibility of BEIS. We sought stakeholder views on mitigations should any legislative changes not be implemented by 1 April 2023, and sought stakeholder feedback on how first comer reinforcement reimbursements might be treated going forward.

2.133. Stakeholder responses on this matter ranged from considering reimbursements unnecessary (or not a factor in investment decisions) through to proposed retention of reinforcement payments to pre-reform first comers, either through "grandfather clauses" or "time limitations". Those who wanted to retain pre-reform arrangements considered continued reimbursements of particular importance for historic network extension schemes. Some respondents supported the idea of interim measures outside of legislative change, with support expressed for both measures as a temporary or more enduring solution.

2.134. We believe ECCR needs to be amended to give effect to our proposed charging reforms. We consider that these changes are unlikely to face further reform as a consequence of our coming DUoS review due to the ECCR's explicit connection charging focus, and therefore delay to legislative change should not be necessary.

2.135. We further consider that such legislative changes may include consideration of providing assurances to connections which have been made upon the explicit basis of recovering second comer contributions, for example where connections can demonstrate their inclusion as part of a regional development plan.

2.136. The need for ECCR to be amended poses a significant risk to implementation of our reforms. Without legislative change reflecting our proposed reforms, we will be unable to approve the DCUSA modifications required to enact such changes.

2.137. BEIS are aware of the criticality of ECCR amendments on the treatment of second comer contributions for the delivery of our connection charging boundary proposals and consequent code modifications. Due to these critical dependencies, we are continuing to liaise with BEIS to seek continued assurances that this legislative change can be delivered in accordance with an implementation date of 1 April 2023. It is our intention to remain close to progress on BEIS' legislative development to ensure continued alignment in the event of delays and to support any requisite changes.

Treatment of existing and in-flight connection applications

2.138. Further clarity was sought by some respondents with regards to the treatment of in-flight projects. It is our view that our minded-to proposals should not affect connection applications made, in process or completed prior to that date.

2.139. Retaining customers' right to terminate and reapply may result in a drop off in connection requests on the approach to 1 April 2023, followed by a surge in applications seeking to benefit from shallower connection charges. This is something that we expect to mitigate for through our proposals set out later, in paragraph 2.177. This could mean that applicants choosing to reapply face longer waiting times for their connection than they do at present.

2.140. We are of the view that customers should retain the right to terminate and reapply for their connection after 1 April 2023 if they choose to take advantage of the shallower charging boundary by going to the back of the connections queue. The right to termination is a well-established approach, and it is one that allows customers to make a choice between speed of connection and cost.

2.141. We do not consider that in-flight projects should be permitted to reset the terms of their connection agreement whilst also retaining their position in the queue in the transition to 1 April 2023 changes. We anticipate this would impose a considerable administrative burden and cost, and it could be highly complex and contentious (given the potential impact other connectees) for what is a temporary and limited issue. We are seeking your views on this proposal (**see question 2f**).

2.142. We are of the view that the intent and possible direction of policy change under our reforms have been signalled in good time, since at least the December 2018 launch of our Access SCR and more substantively in our June 2021 consultation. We consider that connectees have been well-informed with a significant notice period for these potential changes to the arrangements for applications from 1 April 2023.

Impacts upon interactivity

2.143. Interactivity refers to the process followed by network companies which receive multiple applications to connect to the same part of the network, but where the available capacity would not allow all applicants to connect without physical reinforcement or commercial intervention. This interaction can relate to network capacity, point of connection and application of constraint within an Active Network Managed 'Last In First Off' queue. It can also relate to both the existing and future network.

2.144. The proposed changes to reinforcement contributions will change the costs faced by unsuccessful applicants but may also change how DNOs choose to manage interactive applications as they move to more strategic network investment decisions (ie accounting for the current and future needs of network users overall to deliver more efficient investment, ahead of need where economic to do so). We expect timeliness of connection to remain a factor for connecting customers, and the treatment of interactive connections that also trigger the HCC will need to be established.

2.145. We consider that regardless of the reduced or removed reinforcement costs, the process for managing interactive applications should remain broadly in place. A consistent process is required to ensure that decisions made in how connections are allocated remain transparent, consistent, simple enough to administer in large numbers, and fair for all customers involved.

2.146. One issue raised in response to our original minded to was the treatment of reapplications. Under current arrangements, unsuccessful interactive applicants can keep their queue position and application date. In line with the treatment of in-flight projects, we consider that the rules which applied at the original application date should remain, and therefore interactive projects subject to reinforcement costs will not be able to maintain their queue position if seeking to benefit from the new charging boundary.

2.147. We consider that the principles of interactivity may need to be reviewed in line with our proposed changes, but while the original motivations for interactivity principles may change with the charging boundary, we do not consider current interactivity arrangements to be a barrier to the desired outcomes of these changes. We seek your views on interactivity under **question 2g.**

Rebates on reinforcement charges

2.148. Some respondents raised the possibility of introducing rebates for customers that have already paid for reinforcement under the current cost apportionment arrangements, given they would no longer be required to pay these under our proposed changes. We consider that these were the applicable charges at the time of application, and we do not propose to retroactively apply the new arrangements to existing users. This would come at additional expense to DUoS payers for already sunk cost.

2.149. We consider that parties could not reasonably have expected to have these costs refunded when they connected. We anticipate that there would be additional associated administrative costs, challenges in determining eligible parties and mechanisms for payment. We propose that it would therefore be inappropriate to offer rebates of this nature and that there would be no clear benefit to the DUoS billpayers who would pay.

2.150. We encourage DNOs to be open and transparent about the evolving charging landscape and how this may affect them, especially with their prospective connection customers in the lead up to 1 April 2023.

Minimum Scheme alignment

2.151. Some respondents sought clarity on whether the current Minimum Scheme, as set out in the Common Connection Charging Methodology (CCCM), would align with our proposals to set different charging boundaries for demand and generation.[17]

[17] As defined in DCUSA version 13.7, paragraph 1.1 of Schedule 22 – Common Connection Charging Methodology

2.152. Under the Minimum Scheme, DNOs are obliged to provide customers with an offer at lowest overall cost to provide the required capacity. This may not always result in the lowest connection charge for the connecting customers, as the lowest cost currently considers both reinforcement and extension assets where both are required.

2.153. We consider that the existing Minimum Scheme definition should continue to apply for both demand and generation connections. While demand connections will have their connection offer calculated based on reinforcement costs they will not be required to pay, this method will lower reinforcement charges for the DUoS billpayer while still resulting in lowest cost connection for demand customers.

2.154. We consider that calculating least cost using assets that the connecting customer may not be required to pay towards is an appropriate approach allowing for DNOs to meet their statutory and licence obligations to develop, maintain and operate an efficient, coordinated, and economical electricity distribution system. In addition, this method is consistent with our proposals for calculation of the HCC.

2.155. Our original minded to position took consideration of the potential for flexible resources to defer the need for network reinforcement, and this option would factor in the associated costs. Further work is required to understand the feasibility of calculating flexibility based costs over asset lifetime and reinforcement deferral, however we do not consider DNOs to be prevented from considering non-build solutions in their calculation of Minimum Scheme costs.

2.156. We seek your views on whether the Minimum Scheme requires any clarification or amendment following our proposed charging boundary changes (**see question 2h**).

Clarity on the 'point of connection'

2.157. Our proposed charging boundary reforms rely upon some definition of what is considered at, or above, the 'point of connection', with regards to where connection charges are levied. This has historically been set out in a table within the Common Connection Charging Methodology (CCCM). Some stakeholders sought clarity on the enduring treatment of these voltage groupings going forward.

2.158. It is our expectation that the demarcation between voltage levels will continue to be at circuit breakers on the lower voltage side at point of transformation. The proposed changes to charging boundaries would need to be reflected in the tables and examples within the CCCM, an activity which we consider DNOs well-placed to inform through code working groups.

2.159. It is also our expectation that the clear illustration of such demarcations and charging boundary changes will be included in our SCR decision publication and signalled for inclusion in the CCCM, with the CCCM connection charging examples to be updated accordingly.

Non-firm connections and interactions with access rights proposals

2.160. Some respondents were concerned that the proposed access rights for non-firm connections would require DNOs to treat all non-firm connections as interim measures, and to deliver the full capacity of a firm connection no matter the cost in due course. This is not the intent behind our access rights proposals, which accommodate enduring non-firm connection arrangements where this is the customer's preference. We further clarify this in Section 3 of this document which details our access rights proposals.

2.161. Other respondents raised concerns with regards to the impact of our access rights proposals on existing customers with a non-firm connection. While these customers currently have the right to apply to 'firm up' their connection, a shallower connection charge is expected to encourage more applications of this kind from 1 April 2023, resulting in additional pressure on DNOs to process high volumes of connection applications.

2.162. We have considered options to alleviate the pressure on DNOs dealing with higher volumes of applications, including whether any Ofgem intervention is required to achieve the desired prioritisation of new connection requests.

2.163. The options considered included a moratorium period following 1 April 2023 for applications from non-firm connection customers seeking to firm up. A moratorium, wherein applications from these customers would not be accepted for a set period, was posed as a potential option by our Delivery Group. A by-product would also be deferment of the full cost impact of our proposals on DUoS billpayers, possibly beyond the ED2 period. The proposal has potential to mitigate total cost as well, as DNOs may be able to plan for necessary reinforcement and procure flexibility services more strategically over that period.

2.164. We consider that a moratorium period for new applications from existing non-firm connections is at odds with the improved access rights for non-firm connections proposed through this SCR. This would put existing customers at a significant disadvantage compared to new applicants, or even their current access rights.

2.165. We further consider that preventing applications from this customer group could be considered undue discrimination and may prevent more efficient and strategic network reinforcement decision-making. Reinforcement needs may not be fully understood if applications are prevented from coming forward and triggering that investigative work.

2.166. With regards to the prioritisation of new connections over existing, we do not propose to introduce any specific measures to limit or specify the distinct treatment of these applications, as we believe these requests would be best left to the DNO queue management process, as is the current arrangement. This is an area in which we will, outside of the Access SCR, continue to expect that the DNOs update and standardise their queue management processes to deliver improved consistency and transparency for connecting customers.

2.167. We are seeking your views on whether you agree with our proposed treatment of non-firm applications seeking to obtain a firm connection, including any risks presented by this type of application over others (**see question 2i**).

How will we resolve the lack of commonality regarding service upgrades?

2.168. In December 2021 we published a letter clarifying our position on the treatment of service upgrades for existing distribution connections to single occupancy premises.[18] We issued this letter in light of differing DNO interpretations of this aspect of the CCCM, specifically, in relation to whether these types of work should be customer funded or DNO funded (and recovered through DUoS charges).

2.169. Our letter sets out that the majority of DNOs already fund this type of work, or plan to do so from the start of RIIO-ED2 in April 2023, which aligns with the implementation of our

[18] Letter on Clarification on the treatment of services upgrades: https://www.ofgem.gov.uk/publications/clarification-treatment-service-upgrades-existing-distribution-connections-single-occupancy-premises

proposed Access SCR changes. We outlined our view that different interpretations of connection charging policy can lead to different costs and outcomes for customers for otherwise identical types of work, and that applying the interpretation that these works should be DNO funded would be in consumers' interests.

2.170. We have clarified how we believe DNOs should be more consistently interpreting their obligations in relation to which connection services they should fund, and we understand that DNOs are already working to make these changes. We therefore do not intend to include further direction on this specific issue as part of our Access SCR final decision.

Implementation mitigations

2.171. In our June minded to consultation we set out that we expected our finalised reforms to be implemented from 1 April 2023. Our proposal of shallower connection boundaries will transfer some costs from the connecting customer to electricity billpayers through DUoS charges.

2.172. One potential effect of lower connection charges could be an increase in the volume of new connection requests, arising from both new applicants that will become more financially viable under the charging boundary changes, and a backlog of applications delayed until reforms are in place.

2.173. The first of these applicant types may result in a more enduring rise in application numbers, and therefore present a low-risk effect requiring adjustment from DNOs. The second would represent a temporary but higher delivery risk that may be difficult for DNOs to predict or mitigate without additional support. While the first can be assessed and responded to over time, the temporary risk is elevated precisely because of the unknown degree to which volumes are likely to increase, and for how long they will remain elevated.

2.174. If a surge in applications is observed following 1 April 2023, DNOs may initially face difficulty in continuing to meet their licence obligations with regards to connection offers, namely:

- Standard Licence Condition (SLC) 12 (to quote each application within 65 working days)
- SLC 15A (to issue at least 90% of connection offers within Guaranteed Standards of Performance)

- SLC 15 (to offer at least 90% of connection offers to ICPs/IDNOs)

2.175. Any delays to the connections process have implications for customers, who may face an additional cost burden from longer lead times to connect. Confidence in the application timeframe, as well as maintaining existing standards where possible, are therefore both high priorities in our consideration of these implementation risks.

2.176. While we consider longer-term increases to connection applications within the bounds of DNOs capacity to accommodate, we recognise that there is a risk of a temporary surge following 1 April 2023 as a direct result of Ofgem-directed reforms. If unmitigated, this could result in DNOs failing to meet their licence obligations, as well as customers being exposed to longer than expected lead times to connect.

2.177. We are therefore proposing to consider options to mitigate the impacts of these proposals on connections delivery and these licence obligations. We welcome stakeholder insights on the needs case for Ofgem interventions to manage connection volumes immediately following implementation of our reforms.

2.178. We are minded to consider temporary mitigations for DNOs with respect to these licence obligations. These may take the form of extensions to time to connect. We are interested in stakeholders' views on whether certainty of connection timeframes would be preferable to the risk of not connecting within the current acceptable timeframes.

2.179. Other types of mitigation might grant DNOs permissions to not meet their obligations in a set window of time, on a percentage of applications. This may ease the burden on DNOs, while still allowing most projects to proceed within existing timeframes. However, this method may introduce significant risk of uncertainty if the projects facing longer lead times have not factored in such delays at point of application.

2.180. Further to the needs case, we seek stakeholder insights as to the duration of any such mitigations. We are conscious that permitting delays to connections would negatively impact connecting customers and that this effect would be greater the longer such measures were in place. We seek all views on these implementation risks under **question 2j.**

3. Access rights

Section Summary

This section provides further details on our June 2021 minded to proposals to better define non-firm access arrangements at distribution. We are proposing that curtailment limits are agreed between the distributor and the connecting customer on the basis of maximum overall network benefit. We are also minded to introduce end-dates for non-firm access arrangements.

We confirm our position not to go further in defining or standardising time-profiled access arrangements beyond what distributors can currently offer today.

Consultation questions on access rights proposals

Question 3a: Do you agree with our proposal to exclude customer interruptions and transmission constraints from the definition of curtailment with respect to distribution network access arrangements?

Question 3b: Do you agree that the curtailment limit should be offered by the network based on maximum network benefit and agreed with the connecting customer?

Question 3c: Do you have any views on the principles that should be applied to ensure curtailment limits are set in a consistent manner?

Question 3d: Do you agree with our proposal not to introduce a cap for flexibility payments made should any curtailment in excess of agreed limits be required?

Question 3e: Do you agree with our proposal to introduce explicit end-dates for non-firm arrangements? Are there any mitigations for DUoS billpayers we should consider?

Question 3f: Do you have views on whether the end-dates should take into account only current known or likely works, or if it should allow time for wider developments to take place?

Question 3g: Do you have any comment on our proposal not to further define or standardise time-profiled access arrangements?

Context

3.1. In our June minded-to consultation, we proposed better defining the terms of network access at distribution. We proposed not to further define access rights at transmission.[19]

3.2. Network access rights define the nature of a user's access to the electricity network and the capacity they can use – how much they can import or export, when and for how long, and whether their access can be interrupted and what happens if it is. Most customers on the distribution network presently have limited choice about the terms of their access. Current access arrangements are also not explicit about the nature of access rights being granted to the system.

3.3. As the distribution network becomes more constrained, we consider that flexible, non-firm access arrangements could become more widely used as a tool for network operators to plan and develop the network. In many instances, network operators are already utilising these arrangements whilst providing users with a quicker and often cheaper network access.

3.4. However, where flexible connection arrangements have been introduced, they have typically lacked definition and require users to take on a significant risk of curtailment with no indication of when curtailment will be removed. There is no standard definition of curtailment and how these arrangements work can vary greatly across network operators.

3.5. We believe that better definition, consistency, and transparency of flexible access arrangements would support more efficient use and development of system capacity whilst better meeting consumer needs. Our proposals would also provide more customer certainty and protect them from curtailment risks.

3.6. The feedback we received regarding our access rights proposals were broadly supportive. However, stakeholders challenged us to provide more detail on how the new arrangements would work in practice.

[19] In section 4.9 of our June 2021 minded-to we said that in comparison to distribution arrangements, existing transmission non-firm access arrangements are relatively well-defined. Given this, transmission connected users have not expressed significant desire to reform current arrangements. However, we encourage NGESO to continue to consider the scope for improvements to the design of non-firm access at transmission.

3.7. Since the minded-to consultation closed, we have worked in conjunction with the Delivery Group working groups to identify the practical changes to licenses and codes required to give effect to our proposals. Through these working groups, we identified areas of our minded-to position that required further clarification ahead of final decision. We provide further detail on these areas in the sections ahead.

Summary of minded to consultation responses on Access Rights

3.8. The majority of responses to our access rights proposals proposals were supportive (67%), with the remainder offering mixed responses (33%). There were no responses that were wholly unsupportive of our proposals.

3.9. Those who offered broad support generally agreed that better defined access rights arrangements at distribution would provide more certainty for users and could lead to more efficient use of existing network capacity. Many respondents acknowledged that the proposals could speed up connection times, facilitate provision of flexibility, and reduce network peak loads.

3.10. However, many respondents with mixed views expressed concern at a lack of sufficient detail in our proposals, specifically around important definitions (eg non-firm, curtailment, and small users) and how our proposals might work in practice (eg how curtailment limits should be set and how they would be enforced). Hence, we have been working with Delivery Group members to provide clarity on these areas in our updated minded-to position.

3.11. Key views and suggestions from respondents on specific proposals are outlined below.

Definition of non-firm access rights

3.12. The majority of respondents supported our proposal to introduce better defined non-firm access choices at distribution in principle, to protect from and provide more certainty to customers at risk of open-ended curtailment.

3.13. One respondent saw the proposal as beneficial for increased development of renewable generation projects. Others felt that robust monitoring, transparency, and data would be important for customers to make informed connection choices.

3.14. However, many respondents challenged us to provide more detail on how potential curtailment breaches would be addressed and how this would be backed up with compensation. Other feedback included the importance of limiting hours curtailed to prevent redundant network capacity as well as the need for clear forecasting to better understand the levels of curtailment that may be required.

Time-profiled access rights

3.15. Our proposal to introduce new time-profiled access choices at distribution received broad support. Respondents perceived value on switching away from peak demand and felt that the proposal would give clarity and certainty to DNOs and developers on the impact of new connections. Respondents observed that some industries are unable to flex their demand, however, so that the proposal would not be suitable for all users.

3.16. There was a general view that the proposal would allow parties to connect more quickly and provide better choice on flexible connection arrangements. However, adequate penalties and enforcement mechanisms would be required to ensure compliance.

3.17. As with non-firm access, many respondents suggested that more detail was necessary to understand how this would work in practice. Several respondents also raised potential dependencies on DUoS reform in order to give effect to our proposals.

Shared access rights

3.18. We asked respondents whether they could identify any benefit to shared access rights. The majority of respondents stated that they could not identify such benefits, and many saw shared access rights as an option unlikely to see a lot of uptake. The rationale provided by respondents was that they add complexity (eg in terms of control and metering equipment, tariffs, compliance and billing) and risk for customers which could lead to disputes. Some responses highlighted that potential advantages of shared access rights could instead be provided through innovation and flexibility in connection design and contracts as well as technologies such as active network management.

3.19. Nevertheless, a number of respondents raised that shared access rights present an opportunity to better value flexibility, particularly for mixed technology projects. In such cases, respondents argued that shared access rights could help reduce curtailment needs and potentially the need for reinforcement. One respondent argued that shared access should be available to help lower costs, increase network utilisation efficiencies and increase local balancing, collaboration, integration, and resilience.

3.20. We outlined in our June 2021 minded to positions that we do not propose to take forward shared access as part of the Access SCR. However, we do consider further trialling and testing of shared access to be of value and the ENA Open Networks are currently taking this forward alongside their work on trading access.[20]

How to value alternative access rights

3.21. We asked respondents to comment on how to reflect access rights in charges, such as connection charge or use of system charges. Respondents were evenly split on the most appropriate way to value non-firm arrangements. However, many respondents suggested that the most appropriate way to value time-profiled access was via use of system charges.

3.22. Respondents agreed that proposed connection charging reforms will reduce or remove the extent to which alternative access arrangements could be valued through connection charges, and therefore that value to users would primarily be through a quicker connection.

De-prioritisation of transmission access choices

3.23. Respondents largely agreed with the proposal to not prioritise the introduction of new transmission access choices as part of the SCR. Nevertheless, there is a view that a wider review of transmission access arrangements would be beneficial, especially as the transmission network will be undergoing significant change over the next decade. We outlined in our June 2021 minded-to positions that we will continue to work with NGESO to consider the scope for improvements to the design of non-firm access at transmission outside the scope of this SCR.

[20] ENA open networks project – workstream 1 on flexibility and DSO transition: https://www.energynetworks.org/industry-hub/resource-library/open-networks-2021-ws1a-p6-market-simulations-report-v3.1-(29-apr-2021).pdf

Updates to our minded to positions

Non-firm access arrangements

Who is covered by non-firm access arrangements?

3.24. We are minded to introduce better-defined non-firm access options for distribution connected users. However, these new arrangements would not be available to small users, as outlined in our previous proposals.[21]

3.25. Small users are defined as "households and non-domestic users that are billed on an aggregated and non-site-specific basis or who are metered directly using whole current meters". This aligns with the definition used in the Targeted Charging Review and ensures consistency with section 3 of the National Terms of Connection.[22]

What is curtailment and how are curtailment limits defined?

3.26. In our June 2021 minded to consultation, we proposed that non-firm access be defined in relation to the number of hours (or percentage of time) that users have agreed to be curtailed. This gives users a good understanding of the level of curtailment that they would be exposed to and allows the user to make their own forecasts about the amount of energy imported/exported that would be curtailed.

3.27. We propose defining curtailment as any action taken by the network operator to restrict the conditions of a connection except where this restriction is caused by a fault or damage to the distribution system which results in an interruption to the customer's supply. If a customer's supply is interrupted under the definition of a customer interruption, that interruption continues to be covered under the Guaranteed Standards of Performance and thus should not be treated as curtailment.

[21] We set this out in our June minded to consultation and our shortlisting letter: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options

[22] Targeted Charging Review Decision and Impact Assessments: https://www.ofgem.gov.uk/publications/targeted-charging-review-decision-and-impact-assessment

3.28. Similarly, we propose that curtailment as a result of constraints on the transmission network will not be treated as curtailment on the distribution network. We are seeking your views on our proposal to define curtailment in this manner (**see question 3a**).

3.29. We consider that users on a non-firm connection should be able to agree a curtailment limit with their network operator. This curtailment limit would be set via a defined process on the basis of maximum network benefit, taking into account availability behind the relevant distribution network constraint, the forecast time-profiled levels of demand/generation, and a probabilistic assessment of the level of curtailment required (**see questions 3b and 3c**). We propose that the DNOs are well-placed to define and agree how curtailment limits are defined in a consistent manner across networks, in accordance with our position, and we will continue to engage with them on this area in advance of a final direction.

3.30. The network operator would then be required to operate within this threshold and should take these curtailment limits into account when designing and building the network.

What happens if a network operator curtails a user above the agreed limit?

3.31. Should the network operator wish to curtail a user beyond the agreed limits, the network operator will need to procure this service from the market where it is economic and efficient to do so, in accordance with Electricity Distribution Standard Licence Condition 31E (C31E).[23] This ensures that procurement of flexibility is undertaken in a transparent, economic, and efficient manner using market-based mechanisms where possible. It also ensures more consistent treatment of both flexible and firm connections.

3.32. Some stakeholders have expressed concerns that, under the proposed new arrangements, there is a risk that flexibility may not be readily available due to the lack of a viable market or low liquidity in constrained areas. This could lead to undesirable outcomes, for example, excessive costs being passed through to DUoS billpayers or network operators being more conservative in offering curtailment limits. Some suggested that a cap should therefore be introduced on payments made by DNOs who exceed agreed curtailment limits.

---

[23] Reporting guidance on electricity distribution SLC31E: https://www.ofgem.gov.uk/sites/default/files/2021-11/C31E%20Guidance%20%28Draft%20for%20publication%29.pdf

3.33. We acknowledge that flexibility markets are still developing (as outlined in 0 as a reason for why we think it appropriate to take further time to consider DUoS), however, we are proposing not to introduce such a cap for several reasons:

- A cap would not be market based and would be distortive, therefore it would not be in keeping with the principles and policy intent of C31E. We also think that it could also create an incentive to exceed curtailment limits as the most "cost efficient" option.

- Flexibility markets are, at this time, still developing. We consider that higher prices to be a short-term risk and that there continues to be a natural backstop in the cost of physical reinforcement. We believe that the risk of excessive and expensive reinforcement driven by connections will be mitigated to an extent by the detail of our High Cost Cap proposals (see section 2).

- We do not consider that we have received sufficient evidence on the materiality of the risk of unjustified and excessive costs. We believe that DNOs are able to take action to mitigate these risks, for example, in the way that they manage the non-firm stack and efficiently procure flexibility ahead of need (ie before the need to curtail beyond agreed limits arises).

3.34. We are seeking your views on this position (**see question 3d**).

How long should non-firm access arrangements last?

3.35. We are proposing to introduce explicit end-dates for non-firm arrangements, which would be agreed in advance between the network operator and the customer (**question 3e**). We consider that time-limited non-firm arrangements can be a useful tool for network operators to plan and optimise the timing of network investments, leading to more efficient network development over time.

3.36. End dates would ensure that network operators invest in network capacity in a timely way and provide certainty to customers on when their connection arrangements are likely to be made firm. An open-ended arrangement provides no incentive on network operators to resolve the constraint and progress with reinforcement or procure flexibility in a timely manner.

3.37. However, explicit end dates would not apply where a customer does not explicitly request a firm connection or is unwilling to accept the costs of firming up the connection at the point at which the connection agreement is reviewed. It would also not apply where the connection request triggers a High Cost Cap and the connecting customer does not agree to contribute to reinforcement costs above the cap. In such instances, non-firm arrangements can be made on an enduring basis with no set end date.

3.38. A key question is whether end dates should only take into account wider known/likely developments or if it should allow time for other developments to take place, which may or may not materialise in practice. There are risks to both approaches. If the former approach is taken, then less optimal solutions could be deployed leading to less efficient investment. If the latter approach is taken, there is a risk that firm connections are unnecessarily delayed should no further developments materialise, and the solution identified at the time of the connection requests is the same as the solution that actually gets deployed.

3.39. We are seeking your views on these two approaches (**question 3f**). Our minded to position is that end dates should be agreed between the DNO and customers, similarly to how connection dates are currently agreed in standard connection agreements. We are asking the DNOs (via the delivery group) as part of implementation to consider how end dates can be set in a consistent manner including if the time-limits need to be different for various types of connections (eg voltage levels).

Existing customers on non-firm arrangements

3.40. Our proposed changes will not impact existing users' access rights. This includes existing distribution connected users that have agreed a flexible connection. It is already possible for existing users of the distribution network with a flexible connection to apply for a firm connection. Should existing users wish to amend their access rights, then an application must be submitted to their network operator through the normal process.

The value of non-firm access arrangements

3.41. Our proposals to reduce the extent to which users pay for reinforcement costs via connection charges – fully for demand and partially for generation – will reduce or remove the extent to which connection charges reflect a financial value for opting for a non-firm access. However, we consider that non-firm access could still play an important role in facilitating quicker connections to the network, maximising the use of network capacity while allowing network operators to make strategic investments that alleviate constraints (eg via flexibility procurement or strategic reinforcement). We believe that non-firm arrangements, used strategically, can be a bridge to more efficient reinforcement facilitating quicker connections for future customers and enable decarbonisation at lowest costs.

3.42. We explored the option of valuing access rights via a reduced distribution use of system charge. However, it is difficult to accurately reflect the benefits of access rights choices via DUoS charges. For example, the value of alternative access rights is very location specific, whereas use of system charges involve a degree of averaging and approximation. We also had concerns that inaccurately valuing access rights via use of system charges could risk over-valuing flexible access choices and introduce distortions in markets for procuring flexibility.

Time-profiled access rights

3.43. In our June minded-to consultation we proposed introducing time-profiled access at distribution. A user with time-profiled access rights could have a reduced level of access during network peak periods and their access rights could also vary across the year, to reflect seasonal changes in when network peaks occur.

3.44. We said that we thought time-profiled access options could lead to more efficient use and development of system capacity. Users would also be provided with greater certainty upfront about when they would be able to import and export from the network.

3.45. Some network operators are already utilising time-profiled access arrangements to manage the network – for example, bus garages with higher overnight capacity to facilitate charging of electric buses. In these examples, users have benefitted from a quicker and cheaper connection, and network operators have been able to make the most of network capacity whilst developing a more enduring solution.

3.46. We propose that where there is a clear network need, network operators should consider and discuss time-profiled access options with customers when making connection offers. Time profiled arrangements should also be implemented in a transparent manner and reflected consistently in connection agreements with defined triggers for review.

3.47. However, we are minded not to go further in defining time-profiled access arrangements. For example, we will not prescribe a set of standardised time-bands as default options for time-profiled arrangements. It is unclear to us at this stage that introducing more standardised time-profiled access arrangements will deliver benefits beyond what network operators can already offer under current arrangements.

3.48. We are also concerned that standardisation could hamper the use of complex time profiles more appropriate to the site-specific needs of individual customers/groups of customers. Further, defined time-bands would not always accurately reflect local network demand or export peaks.

3.49. We said in our minded-to that there could be scope to reflect the value of time profiled access arrangements via DUoS charges and that the charge design we were considering could have capacity charges vary at different times of the day reflecting how constrained the network is estimated to be. However, DUoS reform is now not expected until after our current suite of proposals come into effect at the start of RIIO-ED2.[24]

3.50. Like non-firm access, we consider that time-profiled arrangements could facilitate quicker connections to the network. If a user's time-profiled arrangement aligns with the DUoS "red, amber, green" time-bands as they currently are configured, users pay less DUoS on the basis that they are shifting usage to "non-peak" periods. This signal, however, is already present irrespective of whether we further define time-profiled arrangements.

3.51. We also do not propose to introduce any changes to the capacity charges or exceedance charges at this stage. Network operators will have to rely on other enforcement mechanisms (physical or commercial) for ensuring that users adhere to their agreed capacity/time-of-use. We propose that this is a matter best resolved between the distributor and the customer.

3.52. We are seeking your views on this position (**question 3e**).

[24] Consultation on Next Steps for DUoS Reform: https://www.ofgem.gov.uk/sites/default/files/2021-10/Consultation%20on%20next%20steps%20for%20DUoS%20reform.pdf

4. Transmission network use of system charges

Section Summary

This section provides further details on our June 2021 minded to proposals, including that small distributed generators should pay TNUoS charges. We have updated our minded to position based on feedback received to reflect that we no longer intend to direct changes to TNUoS under the Access SCR.

Whilst we continue to believe that small distributed generators should pay TNUoS charges, we propose that any decisions on this area take place outside of this SCR and with full consideration of the responses to our recent TNUoS call for evidence.[25]

Context

4.1. Transmission Network Use of System (TNUoS) charges recover the annual Maximum Allowed Revenues and Transmission Revenue Streams of each onshore and offshore Transmission Owner.

4.2. TNUoS charges are set in such a way so as to provide a long-run marginal cost signal at different locations on the GB transmission network, with the remaining costs of the system being recovered through flat residual charges paid by all demand consumers.

4.3. Small Distributed Generation (SDG) does not currently face any positive TNUoS charge, rather it receives, in some locations, a credit called the Embedded Export Tariff (EET) for exporting over peak periods.[26,27] This EET is levied against gross exports. It is based on demand TNUoS charges rather than generation – that is, exports are treated under the TNUoS charging methodology as being negative demand.

[25] TNUoS Reform: Call for Evidence: https://www.ofgem.gov.uk/publications/tnuos-reform-call-evidence
[26] Which we use to mean any generator who: i) is connected to the Distribution network; and ii) does not have a bilateral agreement with National Grid Electricity System Operator for access to and use of the transmission system
[27] The three half hours of highest electricity demand between November and February of any given year, separated by ten clear days – generally known as 'the triad'.

4.4. In May 2018, we approved a change to the Security and Quality of Supply Standards (SQSS) to reflect our view that rather than being negative demand, the output of SDG is positive generation in the context of the transmission system.[28] It is our view that – all other things being equal - 1MW of generation connected to the distribution network will have the same effect on the transmission system as 1MW of generation connected directly thereto. We understand from an initial review of available settlement data that there are Grid Supply Points (GSP) at which the distribution network is exporting onto the transmission system – this can only be as a result of embedded generation connected behind that GSP and is clear evidence that, in practice, some SDG utilise the transmission system in beyond just a theoretical capacity.

4.5. In our June minded-to consultation, we stated that we believed that it would be appropriate for SDG with a Maximum Import Capacity of 1MW or above to face equivalent TNUoS charges to those paid by transmission-connected or larger distributed generators. The threshold of 1MW was identified as a reasonable threshold given its use today as a threshold for participation in the balancing mechanism and ancillary services markets, and the size of generator at which the DNO must notify National Grid Electricity System Operator (NGESO) of the presence of that generator.

4.6. Our June consultation recognised the potential need for broader reform of TNUoS charging in other areas. We therefore propose to delay the application of TNUoS charges to SDG until such time as broader consideration of TNUoS charging arrangements has been considered. We published a Call for Evidence in October 2021 seeking views on the extent to which a broader review of TNUoS charging arrangements is desirable.[29] We are considering the responses to our Call for Evidence and expect to share more information on this area shortly.

Main themes within feedback received on Small Distributed Generation TNUoS charges

4.7. Questions on this proposal were answered by around 120 respondents, with more than half (around 70) disagreeing with our minded-to position. Of the respondents who did not

[28] GSR016: Small and Medium Embedded Generator Assumptions - https://www.nationalgrideso.com/industry-information/codes/security-and-quality-supply-standards-old/modifications/gsr016-small-and
[29] TNUoS Reform: Call for Evidence: https://www.ofgem.gov.uk/publications/tnuos-reform-call-evidence

support our position, a little under half were representatives of, or were themselves, generators, investors, or developers. Most of the responses that were opposed to our proposal focused on the perceived implications of the introduction of TNUoS charges to SDG, not whether in principle levying them would resolve a current distortion.

4.8. We are grateful for the responses received, and the level of engagement in this complex area. The key themes in the consultation responses were:

- Some stakeholders felt that absolute charges in certain parts of GB were too high, using terms such as, "punitive" or, "discriminatory" to describe the output of today's TNUoS charging methodology;

- Some concerns regarding competition between GB generators and their counterparts on mainland Europe were cited, as generators in some EU Member States do not pay, or pay comparatively low transmission charges;

- The role of network charges ought to – in some parties' view – change, such that TNUoS enables generation deployment in areas high in relevant resources rather than being based on the physical network and/or proximity to demand; and

- The current charging regime "incentivises" fossil fuel/conventional generation in the opinion of some respondents – generally this has been linked (in responses) to the negative zonal TNUoS tariffs in southern areas of GB.

4.9. We understand the arguments put to us by those who disagree with our minded-to position, and whilst we do not necessarily agree with all of the arguments put forward, we do appreciate that for generators who have already agreed Contracts for Difference (CfD) or Capacity Market (CM) contracts the introduction of a new charge has the potential to cause a market shock and might have implications for future investments.

4.10. We note that many of the arguments put to us in consultation responses are similar to those proffered in stakeholders' responses to the October TNUoS Call for Evidence in support of a review of the underlying TNUoS charging methodology. There are many facets to the decisions yet to be taken in this area, and we believe that further consideration and analysis is warranted prior to any decisions on TNUoS charges for SDG.

4.11. We are still of the view that in principle, levying TNUoS charges on SDG would be better for competition. In our view, such a change would remove the distortion that exists today, where SDG can participate in the Balancing Mechanism, can have Power Purchase Agreements with Suppliers, can export onto, and can otherwise utilise the transmission system without contributing to the ongoing costs of that system.

4.12. We have not yet seen convincing evidence that SDG is sufficiently different to transmission-connected, or larger distributed generation to warrant a perpetual differential in charging treatment. We do, however consider – especially in the context of the Call for Evidence - that further work on TNUoS is required before we can reach a final decision. We intend to publish our next steps in respect of TNUoS shortly, and we recognise that there is a longer-term, and much broader discussion to be had between us and stakeholders before reaching conclusions on some transmission charging matters.

4.13. We do not intend to undertake any further work under this Access and Forward-Looking Charges Significant Code Review in respect of TNUoS charges for SDG. We are minded not to direct that code modifications are brought forward to introduce such a change at this time, and we expect that any final decision on this matter will be taken outside of the Access SCR.

5. Consultation questions and how to respond

Section summary

This section sets out a collated list of all questions on which we are seeking stakeholder views, including two further general questions in addition to those set out earlier in this document. It also outlines how to respond, our consultation timescales, and how stakeholders can engage with this consultation process.

Collated list of all consultation questions

1. Introduction

[No consultation questions]

2. Distribution connection charging boundary

Question 2a:

- **i.** Do you believe that it is necessary to introduce a High Cost Cap (HCC) for demand, and to retain one for generation?
- **ii.** Do you believe that our proposals to do so represent sufficient and proportionate protection for DUoS billpayers against excessively expensive connections driven reinforcement?
- **iii.** What are your views on retaining the current 'voltage rule' to determine whether the HCC is breached (ie considering the cost of reinforcement at the voltage level at point of connection and the voltage level above)?
- **iv.** What are your views on the principles we have proposed to determine an appropriate HCC level for demand, including the potential for this to be set at a different level to generation under these principles?

Question 2b: What are your views on our proposals to maintain the requirement for three-phase connection requests to pay the full costs of reinforcement, in excess of Minimum Scheme (ie lowest overall capital cost)?

Question 2c:

i. Do you agree with our proposals to maintain the current treatment of speculative connections and is there a need for further clarification on the definition of speculative connections?

ii. Do you agree that our wider connection boundary proposals broaden the disparity between connections deemed to be speculative versus non-speculative? If so, do you believe this needs to be addressed and how?

Question 2d: Do you consider that our proposed DUoS mitigations (a demand HCC, and retaining reinforcement payments for three phase and speculative connection contributions) present a cohesive package of protections for DUoS billpayers? Do you consider these proposals to interact in any way that could counter their effectiveness, and if so, how?

Question 2e: Do our updated proposals to treat storage in line with generation for the purposes of connection charging simplify charging arrangements for these sites and better align with the broader regulatory and legislative framework?

Question 2f: Do you agree with our proposals regarding the treatment of in-flight projects (ie that they should not be permitted to reset their connection agreement and retain their position in the queue), noting they retain the right to terminate and reapply from 1 April 2023 should they wish to be treated under the proposed connection charging boundary?

Question 2g: Do you agree with our proposals to retain the existing arrangements for managing interactive applications? Do you agree with our proposals on the treatment of unsuccessful applicants (that the connection charges at original application date will continue to apply if queue position is retained)?

Question 2h: Do you agree with continuing with the definition of the Minimum Scheme as currently set out in the CCCM? Do you believe this definition requires any further clarification or amendment, and if so, why?

Question 2i: Are there any risks associated with our proposals to allow current non-firm connected customers to seek a firm connection following the changes proposed by our SCR? Do you agree that existing non-firm connected customers that do seek a firm connection should be processed through existing queue management processes as determined by DNOs?

Question 2j: How necessary do you consider Ofgem intervention in Electricity Distribution Standard Licence Conditions 12, 15 and 15A? What duration might such measures be needed, or acceptable, following 1 April 2023? What value do you place on certainty of connection timeframes compared with time to connect?

3. Access rights

Question 3a: Do you agree with our proposal to exclude customer interruptions and transmission constraints from the definition of curtailment with respect to distribution network access arrangements?

Question 3b: Do you agree that the curtailment limit should be offered by the network based on maximum network benefit and agreed with the connecting customer?

Question 3c: Do you have any views on the principles that should be applied to ensure curtailment limits are set in a consistent manner?

Question 3d: Do you agree with our proposal not to introduce a cap for flexibility payments made should any curtailment in excess of agreed limits be required?

Question 3e: Do you agree with our proposal to introduce explicit end-dates for non-firm arrangements? Are there any mitigations for DUoS billpayers we should consider?

Question 3f: Do you have views on whether the end-dates should take into account only current known or likely works, or if it should allow time for wider developments to take place?

Question 3g: Do you have any comment on our proposal not to further define or standardise time-profiled access arrangements?

4. Transmission Network Use of System Charges

[No consultation questions]

5. General questions

Question 5a: Has the additional information in this consultation affected any of the views your previously submitted in response to our June 2021 consultation (if so, in what way)?

Question 5b: Do you have any other information relevant to the subject matter of this consultation that we should consider in developing our proposals?

How to respond

5.1. We want to hear from anyone interested in this consultation. Please email your responses to the questions we have asked in this consultation, including supporting evidence where available, to FutureChargingandAccess@ofgem.gov.uk by 21 February 2022.

5.2. We will publish non-confidential responses on our website at www.ofgem.gov.uk/consultations. Further information on our approach to confidentiality and data privacy can be found in Appendix 1.

Access SCR forward timescales

5.3. We are presently working towards the conclusion of the Access SCR. We anticipate our final decisions and a direction to raise code modifications in the coming months, subject to possible changes in our final positions in response to the feedback we receive from consultation.

5.4. We are conscious that the industry-led process to develop code modifications that give effect to our proposals is a time consuming process. We are therefore seeking to maximise the time available for the necessary modifications to be raised. Pending review of the responses to this consultation, we believe that the earliest possible date for a final decision and a direction for change proposals/modifications to be raised is Spring 2022.

5.5. We are therefore planning according to the following target milestones:

- This consultation closes – 21 February 2022
- Decision on DUoS SCR – expected February 2022
- Publish Final Access SCR decision and direction – expected Spring 2022
- Industry working groups on code modifications – expected Spring 2022
- Consultation on supporting licence changes – expected Summer 2022
- Decision on relevant code modifications – expected Autumn 2022
- Proposed reforms begin to take effect – from 1 April 2023

Your response, data and confidentiality

5.6. You can ask us to keep your response, or parts of your response, confidential. We'll respect this, subject to obligations to disclose information, for example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions, court orders, government regulations or where you give us explicit permission to disclose. If you do want us to keep your response confidential, please clearly mark this on your response and explain why.

5.7. If you wish us to keep part of your response confidential, please clearly mark those parts of your response that you *do* wish to be kept confidential and those that you *do not* wish to be kept confidential. Please put the confidential material in a separate appendix to your response. If necessary, we'll get in touch with you to discuss which parts of the information in your response should be kept confidential, and which can be published. We might ask for reasons why.

5.8. If the information you give in your response contains personal data under the General Data Protection Regulation (Regulation (EU) 2016/679) as retained in domestic law following the UK's withdrawal from the European Union ("UK GDPR"), the Gas and Electricity Markets Authority will be the data controller for the purposes of GDPR. Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. Please refer to our Privacy Notice on consultations, see Appendix 4.

5.9. If you wish to respond confidentially, we'll keep your response itself confidential, but we will publish the number (but not the names) of confidential responses we receive. We won't link responses to respondents if we publish a summary of responses, and we will evaluate each response on its own merits without undermining your right to confidentiality.

General feedback

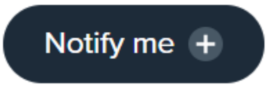
5.10. We believe that consultation is at the heart of good policy development. We welcome any comments about how we've run this consultation. We'd also like to get your answers to these questions:

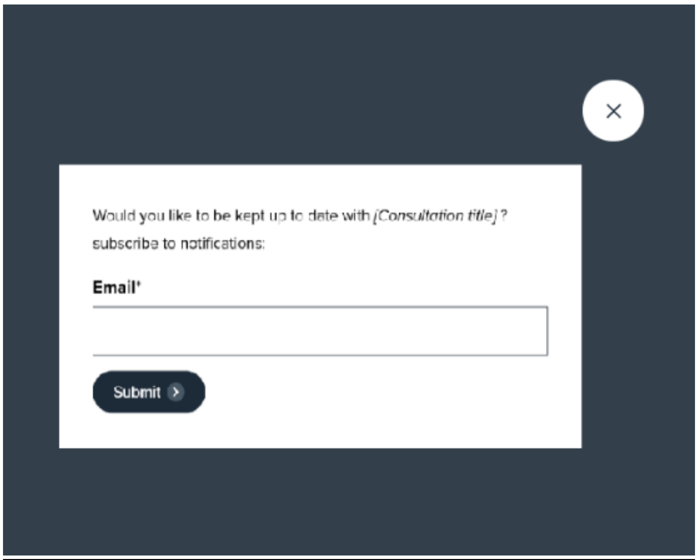
1. Do you have any comments about the overall process of this consultation?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?

4. Were its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

Please send any general feedback comments to stakeholders@ofgem.gov.uk

You can track the progress of a consultation from upcoming to decision status using the 'notify me' function on a consultation page when published on our website. ofgem.gov.uk/consultations.





Once subscribed to the notifications for a particular consultation, you will receive an email to notify you when it has changed status. Our consultation stages are:

Upcoming	▶	Open	▶	Closed (awaiting decision)	▶	Closed (with decision)

Appendix 1 – Privacy notice on consultations

Personal data

The following explains your rights and gives you the information you are entitled to under the General Data Protection Regulation (GDPR).

Note that this section only refers to your personal data (your name address and anything that could be used to identify you personally) not the content of your response to the consultation.

1. The identity of the controller and contact details of our Data Protection Officer

The Gas and Electricity Markets Authority is the controller, (for ease of reference, "Ofgem"). The Data Protection Officer can be contacted at dpo@ofgem.gov.uk.

2. Why we are collecting your personal data

Your personal data is being collected as an essential part of the consultation process, so that we can contact you regarding your response and for statistical purposes. We may also use it to contact you about related matters.

3. Our legal basis for processing your personal data

As a public authority, the GDPR makes provision for Ofgem to process personal data as necessary for the effective performance of a task carried out in the public interest. i.e. a consultation.

4. With whom we will be sharing your personal data

We will make your response as provided available on our website, unless you specify that your response, or parts of it, should be confidential. In which case, we will not share your response unless we are required to do so subject to obligations to disclose information, for example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions, court orders, government regulations or where you give us explicit permission to disclose.

5. For how long we will keep your personal data, or criteria used to determine the retention period.

Your personal data will be held for as long as an audit trail on decision-making relating to the questions discussed in this document should reasonably be available.

6. Your rights

The data we are collecting is your personal data, and you have considerable say over what happens to it. You have the right to:

- know how we use your personal data
- access your personal data
- have personal data corrected if it is inaccurate or incomplete
- ask us to delete personal data when we no longer need it
- ask us to restrict how we process your data
- get your data from us and re-use it across other services
- object to certain ways we use your data
- be safeguarded against risks where decisions based on your data are taken entirely automatically
- tell us if we can share your information with 3rd parties
- tell us your preferred frequency, content and format of our communications with you

- to lodge a complaint with the independent Information Commissioner (ICO) if you think we are not handling your data fairly or in accordance with the law. You can contact the ICO at https://ico.org.uk/, or telephone 0303 123 1113.

7. Your personal data will not be sent overseas

8. Your personal data will not be used for any automated decision making

9. Your personal data will be stored in a secure government IT system

10. More information

For more information on how Ofgem processes your data, click on the link to our "Ofgem privacy promise".