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Making a positive difference
for energy consumers

Appendix 1 - Details of decision on the scope of the review

Contents

1. Introduction to Appendix 1: Details on scope of review

1.1. In this appendix, we set out the details of our decision on the scope of the review. This includes the reasoning for the scope of the Significant Code Review (SCR) and the priority areas, and the areas we propose that industry progresses outside the SCR as part of the wider review.

1.2. Our decision on the scope of review has been informed by our assessment of the overall case for change, which includes our consideration of the responses received on this subject through the consultation. Most respondents supported the case for change. However, a number of other views were raised including -

- Some parties considered that we over-prioritised the importance of "levelling the playing field" between transmission and distribution. Others agreed that this was a priority.
- Some respondents questioned how we characterised the impact of distribution-connected generation on transmission networks.

1.3. We think these issues are most relevant for our consideration of how distributed generators[1] and other distribution-connected entities (including onsite generation and demand side response) face transmission charges. We therefore discuss our reasoning on these points further within the Transmission Use of System charges section at paragraph 3.44 onwards.

1.4. Respondents also differed in their views on whether Ofgem or industry should lead different elements of the review and which specific elements should be in scope. We set out our reasoning for our decisions in this respect in the main SCR launch letter.

1.5. This decision has been informed by our assessment of the responses received to the consultation, and the supporting analysis undertaken by Baringa and industry taskforces earlier this year.[2] We previously identified the need for reform through our work on flexibility and embedded benefits, and in our Strategy for regulating the future energy system.[3] We formally launched the work through our November 2017 working paper.[4]

1.6. We summarise the key themes from respondents on the scope of review within this appendix. Appendix 4 contains a more detailed summary of the views we received across all the consultation questions.

1.7. We have made refinements to the scope of the review in some areas compared to the consultation proposal. We want to ensure that the scope of our review is manageable and focuses on areas that we consider will deliver the greatest value to consumers. Therefore, we have deprioritised some areas (but which are still within the scope of the review) and excluded others from our review. We note it is possible to change the scope of an SCR as it progresses. Should we consider

[1] Note that distributed generators (DG) can also be referred to as embedded generators
[2] The Baringa analysis is available (link here) and the taskforce reports (link here).
[3] Our 2015 flexibility position paper (can be found here) and our joint call for evidence between Ofgem and BEIS (here). For our work on embedded benefits, see our July 2016 Open Letter (here) and December 2016 update (here). Our Strategy for regulating the future energy system is also available (here)
[4] Reform of network access and forward-looking charges: a working paper, available here.

there is a need to do so, we would look at this at the appropriate time. So areas currently excluded could potentially be brought into the SCR later.

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2. Scope of the review of access arrangements

Summary of decision

We have decided to include the following areas within the scope of the SCR:

- **Improved definition and choice of access rights for transmission and distribution**

  Priority areas:
    - Increased clarity and choice of the firmness of access, including clarifying the access rights of distribution-connected users to the transmission network
    - Increased choice around time-profiled access
    - Increasing clarity and choice for small users' access rights[5]

Subject to further analysis:
- Whether to allow users to share access rights

Other areas we may consider[6]:
- Short-term duration access rights
- New conditions of access (eg as 'use-it-or-lose-it' or 'use-it-or-sell-it').

Outside the scope of the SCR, we consider that the industry should lead a review on:

- **Improved allocation of access rights**
    - Improving connection queue management
    - Continue to develop mechanisms to enable distribution-connected users with non-firm access to trade with others to reduce their curtailment
    - Better enable the exchange of access rights between users.

For clarity, we think this work should cover the access rights that are available from Independent Distribution Network Operators (IDNOs).

We have also decided to exclude from the review the development of:

- Introducing fixed duration long-term access rights
- Introducing geographically exclusive local access rights that don't allow access to the rest of the system.

Improved definition and choice of access rights

Consultation position and feedback received

2.1. We proposed to review the definition and choice of access rights. Table 1 sets out our consultation proposals on the areas we thought could benefit from improved choice:

Table 1: Summary of access terms

Access right choice	What this means	Our consultation proposal
Firmness of rights	This is the extent to which a user's access to the network can be restricted and their eligibility for compensation if it is restricted.	We thought that better defining and giving improved choice around these options could have value, including improving the clarity of distribution-connected users' access to the transmission network, and proposed they should be included within a review.
Time-profiled rights	This would provide choices other than continuous, year-round access rights (eg 'peak' or 'off-peak' access).	
Short-term rights	This would provide a choice for limited duration access (eg one year) where long term access is not immediately available or where the user does not want to make a long term commitment	
Fixed duration long-term rights	This would provide the option for long-term access rights of fixed length (eg 15 years)	We were less certain of the value of these options and consulted openly on whether they should be included within a review.
Exclusive local or 'shallow' access rights	This would offer access to a given geographical area or a specific voltage level, but exclude access to the whole GB system.	

[5] By small users, here, we are referring to those users who do not have a specified capacity. These users are typically those that do not have Current Transformer meters.
[6] At this point we do not consider these areas as priorities for change, but we will review the materiality of these matters and are prepared to take further action during the SCR if further evidence emerges to support this.

New access conditions	This could involve introducing conditions on access, for example 'use-it-or-lose-it' or –use-it-or-sell-it'.	We thought that this option could have value in supporting allocation of access and proposed they should be included within a review.
Clarifying access rights and choices for small users	This could involve requiring small users to specify the level of capacity they require. They could also potentially choose from wider access options above a minimum 'core' level, to ensure they secured adequate access, or principles-based obligations on suppliers as an alternative protection measure.	We thought that this option could have value and proposed this should be included within a review.

2.2. In general, respondents broadly supported improving the definition and choice of access, with a particular focus on firmness and time-profiled rights. A small number of respondents raised 'shared' access rights as a potential variant and possible alternative to geographically exclusive local access rights. We think these could allow users that are spread across multiple sites in the same broad area to obtain access to the whole of the network (rather than just part of the network), up to a jointly agreed level. They would coordinate to ensure their combined usage remained within this defined limit. Some stakeholders expressed a strong desire for the benefits of local energy to be reflected in network access and charging arrangements.

2.3. Although there were some mixed views, generally, respondents did not see merit in fixed duration long-term access rights (eg of multiple years), suggesting there might not be sufficient certainty about users' long-term requirements. There was some recognition of the potential for short term fixed duration rights to have benefits, linked to flexibility, but a number of respondents saw fixed term rights as a lower priority than some other areas.

2.4. Respondents broadly supported reviewing access rights for small users, but noted some challenges with options to set a minimum 'core' access level. We discuss this further below.

Decision

2.5. Having considered the consultation responses, we have decided to review the definition and choice of transmission and distribution access rights, prioritising the following options within the scope of the SCR:

- **Increased clarity and choice of firmness levels, including clarifying the access rights of distribution-connected users to the transmission network.**

- **Increased choice around time-profiled access.**
- We confirm our position to review access options to **improve definition and choice for small users**, including households.

2.6. We recognise that a key challenge in defining access rights for small users relates to variability in the nature of household demand and how "essential" usage might be understood, together with consumers' evolving needs. We will explore the feasibility and desirability of defining a minimum basic level of access for small users (or a subset of small users), as well as having threshold limits for sharper charging signals (discussed further in section 3). However, we recognise that it may not be possible to take this approach forward due to the difficulty in defining "essential" usage for the heterogeneous and evolving demands of electricity consumers. We will therefore also consider alternative approaches to ensure that customers in vulnerable situations are protected.

2.7. We intend to **explore the feasibility and value of enabling users to share access rights**. The option of sharing access was raised through consultation and we consider it could have value in unlocking local capacity and helping to signal the benefits of local matching. We recognise that, given this, assessment of this option has been more limited than for others which were developed ahead of the consultation. There is a possibility that, subject to this assessment, this may become one of our priority areas in the SCR.

2.8. We are including the following arrangements in the SCR but see them as a lower priority. At this point we think we may not make changes in this area, but we will review the materiality of these matters and are prepared to take further action during the SCR if further evidence emerges to support this -

- **Development of short-term duration access rights.**
- **Developing new conditions of access**, such as 'use-it-or-lose-it' or 'use-it-or-sell-it'.

2.9. We want to develop arrangements which recognise the benefits that all energy arrangements, including local energy schemes, can bring. We have however decided to exclude the development of geographically exclusive local access rights from the SCR and wider review. Instead, we intend to pursue other options to reflect where local energy projects bring network benefits in a simple and efficient way, including more cost-reflective network charges and the potential for shared access rights.

2.10. We have also decided to exclude fixed duration long-term access rights from the review.

2.11. We note there is flexibility to change the scope of an SCR as it progresses. Should evidence suggest there is a need to do so, including the incorporation of areas not covered by the original scope, we would consider this at the appropriate time.

2.12. For clarity, as part of this work we will also seek to improve the definition and choice of access rights that are available from IDNOs (eg improving the definition and choice and choice for small users, including households, connected to networks owned by IDNOs).[7]

Reasons

Areas that we are prioritising within the SCR

2.13. DNOs have already begun to offer different access choices at distribution level through "flexible connections". Primarily, these are focused on offering the choice of non-firm access in order to allow quicker and cheaper connection to the network. These tend to have no defined cap on the extent to which a user's access can be interrupted. The development of non-firm distribution access rights could improve choice and lead to better-defined access choices that allow users to better manage the risk of curtailment. We think these are a welcome development to allow more users to connect through more efficient use of existing network capacity.

2.14. However, we see significant scope for improvement in how well the **firmness of rights** are defined and in the choices available (eg greater clarity on when or how often a user could be interrupted). Such change could improve the attractiveness of these options to users by allowing them to better understand and manage their risk of curtailment, and so aid greater take-up.

2.15. In considering this, we note **access rights of distribution-connected users to the transmission network** are not well defined. Distributed-connected users are in practice generally able to draw from or export onto the transmission network, and can increasingly access markets that have historically been dominated by transmission-connected generation (for example, they can offer services in the Balancing Mechanism). We think there may be value in making rights more explicit for these users. This could include provisions for distributed generators to agree Transmission Entry Capacity[8] and clarifying distributed generators' ability to benefit from the "Connect and Manage" regime.[9] This should improve the consistency of access rights across the whole electricity system and help ensure that generators and other network users are able to compete on a level playing field.

2.16. Similarly, we consider that greater availability of the choice of **time-profiled access rights** could lead to better use of existing network capacity and should allow users to connect more quickly and without the need for expensive reinforcement. We recognise that time-profiled access rights may not be valuable to all users and will consider the challenges associated with the development of time-profiled access rights as part of the SCR.

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[7] Independent Distribution Network Operators (IDNOs) develop, operate and maintain local electricity distribution networks. IDNO networks are directly connected to the Distribution Network Operator (DNO) networks or indirectly to the DNO via another IDNO.
[8] Some distributed generators (eg those with a Bilateral Embedded Generation Agreement (BEGA)) may already hold these rights.
[9] The Connect and Manage transmission access regime was introduced by the government in 2010 and implemented in 2011. Its aim was to improve access to the electricity transmission network for generators by offering generation customers connection dates ahead of the completion of any wider transmission system reinforcements which may be needed. Any resultant constraint management costs are socialised via BSUoS charges.

2.17. The development of an option for **'shared access'** could allow users across multiple sites in the same broad area to obtain access to the whole network (rather than just part of the network), up to a jointly agreed level. They would coordinate to ensure their combined usage remained within this defined limit - both sites' access would be subject to restrictions on their combined maximum import and / or export amounts. This would allow the participating network users to decide how to apportion access rights amongst themselves. For example, two generators in a similar location could agree to share a maximum export capacity of 1MW. Another example could be users who form part of a local energy project working together to optimise capacity usage across several sites.

2.18. As this option has been identified in the course of the consultation it has been subject to less detailed assessment than the others proposed. We think it merits further consideration as a potential means to allow more users to connect in constrained areas of the network. We expect it could help achieve similar benefits to geographically exclusive local access rights in a simpler way, as it avoids issues of market fragmentation and could be less complex to define and verify. We recognise some concerns still apply, such as the need to ensure small users are appropriately protected, and its feasibility would need to be fully assessed. We therefore intend to explore this further as part of our SCR, including assessing how this access option could work in practice (eg the commercial relationship between the relevant stakeholders).

2.19. We think that **new conditions of access** could potentially have value in helping ensure capacity is allocated efficiently. This could include 'use it or lose it' or 'lose it or sell it' options so that those who are not using network capacity that is allocated to them have to release it. However, they may be less necessary if other changes can give adequate incentives to release unused capacity, notably through capacity-based charges or trading. We propose to include new conditions of access within the scope of the SCR, but consider this area is a lower priority, depending on developments elsewhere.

2.20. **Small users' access rights** are not currently well-defined. In practice, most households' access to the system is limited only by their fuse size and they may never have considered or 'chosen' the level of access they have. We think there is a need to consider clearer definitions for small users' access rights as new usages, such as fast charging electric vehicles or heat pumps, could place significant strains on networks. Giving clearer signals about the impact of different types of access on the network can help encourage choices that can reduce costs for all, while enabling users to get the access they need. This includes rewarding those that are willing to be flexible in their usage – for example electric vehicle owners who are willing to adopt "smart charging" outside of network peaks.

2.21. Under the potential access options we intend to consider, an electric vehicle owner may need to nominate a higher capacity level in order to be able to charge their vehicle at a fast rate, for example. They could have different choices around their access. For example, if they were willing to only charge off-peak, opt to charge more slowly or possibly have their charging managed by their DNO, this could reduce their charges relative to fast, uninterruptible charging at peak times. This would reflect the different impacts the types of charging would have on system costs.

2.22. We acknowledge that some households may have relatively limited choice around some of their more essential needs, for example those who have a poorly insulated home and rely on traditional electric heating. Some may be flexible in when they consume electricity, but other users will not readily be able to change their time of usage. We also think we need to ensure that, in offering greater choice of access, small users are not unduly incentivised to opt for levels of access which could have an adverse impact on their welfare.

2.23. We will consider options to mitigate against the potential adverse impacts of our proposed reforms on small users, in particular those in vulnerable situations. This could involve setting a minimum basic access level (or charging threshold – discussed further in section 3).

2.24. We recognise that setting such a threshold would involve addressing a range of challenging questions, as highlighted by respondents. A key challenge relates to the variability in the nature of household demand and in how “essential” usage might be understood, particularly as demand evolves. We recognise that it may not be possible to take this approach forward due to the difficulty in defining essential usage for the heterogeneous and evolving demands of electricity consumers. We will therefore also consider alternative options for protection, in particular for customers in vulnerable situations.

2.25. There are also close links with wider Ofgem policy developments, and other aspects of the SCR, which will need to be considered and coordinated.[10]

2.26. One important consideration will be what we expect consumers themselves to manage, versus what will be the responsibility of their supplier or other intermediary. Currently, the electricity supplier is the primary intermediary between consumers and the wider energy system and faces network charges associated with the consumers they supply, rather than consumers directly.

2.27. After the initial connection or increase in capacity, small users typically have no direct day-to-day consumer relationship with the DNO. This means that the supplier faces the signals and decides how to respond to these, including how to reflect them in the tariffs they offer and whether to provide services to their customers (such as technology to support automated smart charging of electric vehicles) in response to them.

2.28. We intend to consider further what the supplier or other intermediary’s role should be, including whether they could have a role in helping determine the right access choice for their customers and how other protection options such as principles-based licence obligations may have a role. At the same time, we note there may also be a need to build consumer understanding and awareness in support of the reforms we are considering here (and more widely as part of our joint plan with Government’s Plan for a Smart, Flexible Energy System) and will consider this further during the course of the SCR.

[10] For example, the market-wide Half-Hourly Settlement (HHS) reform and Future retail market arrangements – discussed further in Appendix 2

Other areas within the SCR

2.29. We believe that developing options for firmness and time-profiled rights has clearer value to network users and the system than **short-term access rights**. A short-term option could have value where long term access is not immediately available or where the user does not want to make a long term commitment. However, we think it is less of a priority than the other access right choices because the value to network users and the system is comparatively less clear. For example, users generally favour open-ended duration access rights and short-term transmission access options are not commonly taken up, as some respondents also highlighted.

Areas not in scope of the review

2.30. **Fixed duration long term access rights** could theoretically support more efficient allocation of access and enhance certainty for network planning. However, there are a number of practical limitations. For example, respondents said that users generally favour access rights that are 'evergreen' (with no fixed end date), due to the uncertainty of having to reapply for access.

2.31. We also consider that fixing long term rights will not provide more certainty for network planning without financial commitment from users to pay for that access over the defined period of the rights. This could introduce a barrier to entry, especially for smaller parties.

2.32. We would also need to consider whether the charge should be fixed for the period of the right (rather than varying annually, as now). Whilst this may be attractive for some users, without a liquid market for reallocating access, it may lead to a less efficient allocation of access rights as users would not receive updated signals about how the value of their access changes over time. We believe that these practical considerations limit the value of this option and so have decided to exclude it from the review.

2.33. **Geographically exclusive 'local' or 'shallow' access rights** would give users a right to flow electricity solely over a given portion of the network (either within a geographic region or at a given voltage level).

2.34. A local access right would require generation (or demand) to be constantly matched with the demand (or generation) of other local parties. Our analysis suggests that local access rights would be highly complex to develop and implement. They could be challenging to implement and enforce, potentially involving complex system changes. As we noted in our consultation, they would have the effect of fragmenting the market, which could reduce liquidity. There may also be a need to consider potential implications under EU law.[11] We consider that our proposed reforms could deliver similar benefits more simply, offering the prospect of better value.

2.35. We consider that a more cost-reflective charging-led approach could reflect many of the same long run system benefits as a local access option (eg the development of more locationally granular distribution network charges). We also

[11] Specifically, 'Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management' (link here)

think that improving the choice and definition of access rights (with a potential role for shared access or improved flexible connections) could also help users. For example, this could enable local energy projects to get access that matches their needs, more quickly and cheaply, where they can help avoid constraints. These approaches could help unlock value from local flexibility and the wider system.

2.36. We are therefore excluding geographically exclusive local access rights from the review, but we will consider other options which can reflect the benefits of users matching demand and generation locally within the SCR (eg shared access, improved 'flexible connections' and more locational network charges).

Allocation of access rights

Consultation position and feedback received

2.37. In our consultation, we proposed that incremental improvements to queue management activities should be investigated as part of a review of arrangements for the **initial allocation** of access arrangements.

2.38. We proposed that the review would not include the following:

- options for universal auctions for access to existing and new capacity;
- consideration of the role of targeted auctions for the initial allocation of access rights, eg where an auction would be triggered where a queue has formed to connect to the system; or
- changes to Connect and Manage to: extend the policy to allow new connectees to be connected quickly with "financially firm" rights even where this would result in constraints on the distribution network; or to change the existing allocation approach at transmission (other than to clarify its application to distributed generation that are impacted by transmission constraints).[12]

2.39. We also proposed that the review of mechanisms for the **reallocation** of access rights should include developing and assessing options to:

- develop mechanisms to enable distribution-connected users with non-firm access to trade with others to reduce their curtailment; and
- improve the ability to exchange access rights between users.

2.40. There was broad support from respondents for the proposed scope of review for initial allocation of access. Respondents generally agreed with our proposals for a review of incremental improvements to queue management, and to exclude introducing universal auctions, targeted auctions and the Connect and Manage regime to the distribution network at this time.

[12] In this document, we use the term 'financially firm' to indicate that payment is generally agreed where a network user's access is limited due to constraints. This does not necessarily mean they will receive payment in all circumstances where network access is limited - each user's individual terms will be a function of the codes, licences and any individual contractual conditions which apply.

2.41. The majority of respondents supported reviewing the reallocation of access. However, some had reservations about how easy it would be to reallocate access and some concerns about parties speculatively buying network access to trade in the future. We consider these concerns to be valid, and agree that trading mechanisms must be designed in a way that minimises gaming and speculation.

Decision

2.42. We think there should be consideration of incremental improvements to the allocation of access rights (eg better management of connection queues, allowing distributed generation who have non-firm connections to trade with others to reduce the extent they are curtailed, and better enabling the exchange of access rights between users). We think this should be taken forward by the electricity system operator and network companies.

2.43. We have decided not to include the option of using auctions for access rights (either on a universal or targeted basis) within this review. At this time, we are not proposing to extend the Connect and Manage regime to enable generators to connect to the distribution network with financially firm access rights, ahead of any necessary reinforcement of the distribution network.

2.44. We think that there should be development of options to allow those with non-firm access to trade their curtailment obligations with others, and to facilitate the exchange of access rights between users. We think this should be taken forward by the electricity system operator and network companies, outside of the SCR.

2.45. We think that **new conditions of access** could potentially have value, which we discuss under definition of access rights above.

2.46. For clarity, we expect that this work to include all electricity distributors (ie both DNO and IDNO owned electricity distribution networks).

We also expect to the ENA Open Networks programme to address issues associated with the connection process that were identified by respondents (eg improving the provision of information to prospective connection customers).

Reasons

2.47. We consider that better queue management activities should make better use of the existing network capacity and help reduce the time users need to wait to connect. Queue management is an area where electricity system operator and network companies already have a number of improvement activities underway and we consider it is separable from the other areas of the review. We therefore believe that the electricity system operator and network companies should continue to lead this area to maintain existing momentum. There was broad support from respondents for improving queue management activities and we received a range of views about how this could be achieved. We expect the electricity system operator and network companies to consider the potential improvements suggested by respondents to our consultation.

2.48. We consider that better definition of access rights and a decision on the connection-charging boundary would be needed before it is possible to develop proposals for auction design. We also believe that the value of auctions would likely be outweighed by the greater complexity, and there are more incremental improvements that can be made. This view was supported by the majority of respondents. In particular, respondents were concerned about the complexity of auctions for smaller users and the ability for these auctions to generate effective competition. In relation to access for demand users, some respondents also questioned whether it would be right for access to go to the highest bidder.

2.49. To extend the Connect and Manage regime to allow for the connection of users ahead of wider distribution reinforcement, would require the establishment of financially firm access rights at distribution. Currently, access rights for DG to the distribution network are generally not "financially firm". We consider that rolling out "financially firm" access rights at distribution level is unlikely to be achievable in the short term. This is because there is likely to be a need to develop new distribution network planning standards that would outline the level of network resilience needed. This is likely to take considerable time. We consider that other proposed reforms can deliver similar benefits to network users. For example, reviewing the definition and choices of non-firm access rights could reduce risk for network users by giving better information and choice to manage curtailment. This would also provide better information to network operators about where there is demand for new network capacity.

2.50. We believe that facilitating non-firm, distribution-connected generators to trade the extent that they are curtailed and enabling exchange of access rights will support more efficient allocation of access. Currently some users with non-firm access are curtailed when they would place significant value on staying on the network, while other users in the area might be willing to be flexible with their usage to enable this in exchange for payment. This should also help reveal the value of increased network capacity in specific areas.

2.51. We consider that facilitating the exchange of access rights will allow the network to be used more efficiently, by those parties that value it the most. We recognise that where parties in different geographical locations want to trade access, there may be a role for the DNO in converting the value of an access right from one location to another (ie the 'exchange rate' that is applied to each trade of access). We think this will be an important consideration in taking forward this work. We consider that our work to improve the definition of access rights will facilitate the trading of access rights. We encourage the system and network companies to consider how to make the trading of access as simple and accessible for network users. The reforms that we are considering (eg network charging reform and conditions of access) should lead to more efficient use of the network and disincentivise parties from speculatively buying available access with no intention of using it. We also note that the value placed on access will send strong signals to system operators and network companies about the need for new network capacity.

2.52. The ESO and network companies have already made progress improving the reallocation of access and we consider that this work is separable from our proposed SCR. We therefore consider industry should continue to lead on this work, outside of our SCR. More information on this can be found in our main launch letter.

3. Scope of the review of forward looking charges

Summary of decision

We have decided to include the following areas within the scope of the SCR:

- **A wide-ranging review of Distribution Use of System charges**
  - The balance between usage-based and capacity-based charges, including time related charges
  - Improvements to signal how network costs vary by location

- **A review of the distribution connection charging boundary if distribution use of system charges can be made more cost-reflective**
  - Potentially moving to "shallow" upfront distribution connection charges
  - Potential consequential changes, such as whether to introduce user commitment requirements and how to treat existing users who have paid "shallow-ish" connection charges previously

- **A focused review of Transmission Use of System charges**

  Priority areas:
  - How distributed generators are charged
  - How demand users are charged

  Other areas we may consider[13]:
  - The "reference node" used in the model that derives the locational charges for different users and areas

Distribution Use of System charges

3.1. Distribution network charges, also known as Distribution Use of System (DUoS) charges, consist of forward-looking charges and residual charges. In this document, references to DUoS charges are a reference to the forward-looking element of DUoS charges, unless otherwise specified.[14]

Consultation position and feedback received

3.2. We proposed that a "comprehensive" review of forward-looking DUoS charges, was necessary to ensure that they are fit for purpose. This included a review of

[13] At this point we do not consider these areas as priorities for change, but we will review the materiality of these matters and are prepared to take further action during the SCR if further evidence emerges to support this.

[14] Under the current charging arrangements several of the forward-looking charges are subsequently adjusted by scaling the charges up (or down) by the residual charges. The focus of this review is the forward-looking charges. The residual charges are the subject of a separate review, called the Targeted Charging Review (TCR).

the charging methodologies for Extra-High Voltage, as well as High Voltage and Low Voltage.[15] Proposed areas for review included:

- The balance between charging based on usage (which could include charges varying by time-of-use) or based on capacity (a user's maximum usage, either agreed in advance or as measured over a given period).
- Greater locational granularity of charging signals for users at High Voltage and Low Voltage.
- Improved predictability of charges for users at Extra-High voltage.

3.3. We also proposed that charging reforms for small users could involve setting a basic charging threshold, with usage or capacity requirements below this tier protected from sharper charging signals. This could mitigate potential adverse impacts, particularly for vulnerable consumers. This could work alongside a basic access limit, as discussed in paragraph 2.6, or it could be directly-connected if we decided not to pursue an access limit option. Respondents noted some challenges with both protection options and setting a basic access limit, as outlined above in paragraph 2.24.

3.4. The vast majority of respondents expressed support for our proposed scope of review for DUoS charges. Most respondents agreed that a wide-ranging approach focussing on the proposed areas was appropriate, given the breadth of reform that may be required. Some respondents said that the review could create uncertainty, and therefore have a negative impact on investment.

3.5. Principal areas of concern for respondents included: predictability and volatility of charges; consistency between DNO areas; potential for negative impact on renewable and/or flexible generation; ability for users to respond to signals; complexity and cost of more granular charges; interactions with flexibility services; and the need for a more holistic view of network charges (including transmission).

Decision

3.6. Having reviewed the consultation responses, we have decided to proceed with a review of DUoS broadly as proposed in the July consultation. In recognition of feedback querying the extent of our scope, we clarify that this is expected to be a wide-ranging review rather than necessarily "comprehensive". We are not committing to review all aspects of DUoS. We intend to focus on wide-ranging aspects of the charging framework with a focus on the areas identified in paragraph 3.7 below. We do not preclude the possibility of broader changes where they are necessary to achieve alignment with the principles upon which the review is based.

3.7. We believe that focusing on the following aspects of DUoS will help to ensure that charges are more reflective of network conditions and send more effective signals to network users

[15] EHV users are generally charged under the EDCM (Extra-high voltage Distribution Charging Methodology) whereas HV and LV users are charged under the CDCM (Common Distribution Charging Methodology)

- **The balance between usage-based and capacity-based charges.**
- **Improvements to signal how network costs vary by location.**

3.8.. We confirm our consultation position to explore threshold limits for sharper charging signals (eg above a basic usage threshold) for small users, or sub-sets of small users, within the scope of the SCR. As these signals are currently sent to suppliers (rather than consumers directly), it will be necessary to understand how these manifest themselves in tariffs, and how consumers who can be flexible may be able to access savings. We will continue to work to understand better the impact of the reforms for small users, and their ability to respond to signals, developing appropriate mitigation options for adverse impacts, particularly for consumers in vulnerable situations. If we decide not to take forward defining threshold limits for sharper charging signals, we will consider alternative potential approaches to protection, in particular for consumers in vulnerable situations.

3.9. We will consider how changes to DUoS will impact IDNOs, and we will consider whether consequential changes to the IDNO network charging methodologies are required.

3.10. We acknowledge the issues raised by respondents in paragraph 3.5 and will take them into account in our review. This will include evaluating the changes we are considering to DUoS, distribution connection charging and TNUoS holistically.

Reasons

3.11. **The balance between usage-based and capacity-based charges** is a priority area in the review. This is to evaluate whether changes to how charges are based on usage as well as capacity could send more cost-reflective and effective signals to network users. As part of this assessment, we intend to consider time-of-use variants for both usage-based and capacity-based charges. For example, charges could change according to the time of day or season (such as higher charges during peak usage times in the evenings and winter). A greater emphasis on these approaches could have value as they may reflect better the drivers for network infrastructure, and therefore improve the cost-reflectivity of charging signals. We also consider there are benefits to considering alignment of distribution charges with transmission charges. Combined with greater locational granularity, this could introduce network charges (or credits) that vary depending on levels of demand for network capacity and the cost of reinforcement in the local area.

3.12. **Improvements to signal how network costs vary by location** could involve changes to both charging arrangements for those connected at High Voltage and Low Voltage (who face CDCM[16] tariffs) and those connected at Extra-High Voltage on the distribution network (who face EDCM[17] tariffs).

3.13. Currently, CDCM charges are the same across a DNO region, despite the fact that there could be considerable differences in network cost drivers across those

[16] The Common Distribution Charging Methodology (CDCM) is applied to users at High Voltage and Low Voltage
[17] The Extra-High Voltage Distribution Charging Methodology (EDCM) is applied to users at Extra-High Voltage

regions. The model currently makes the assumption that distributed generators are offsetting the need for network investment required to serve demand users, and therefore receive credits through their DUoS charges.

3.14. This approach may have been more appropriate historically, but there are now increasing instances where distribution networks are 'generation dominated'. This means that generators are producing more than the demand in that area and are leading to electricity flows being exported "upwards" through to higher voltages on the network. In places, there is insufficient network capacity to support desired exports, and so generation in these areas is a driver for network costs and constraints. In other places, distributed generators could save costs in future, so they should be able to earn revenues that reflect these savings.

3.15. A further example of the potential value in **greater locational granularity** in DUoS charges is in thinking about the anticipated roll-out of electric vehicles. There is likely to be a need for a number of public charging stations that will have significant electricity demand. They would currently face the same DUoS charges (for connecting at a particular voltage level) regardless of which area of a DNO's network they are connecting to. Yet one area of the network could only have limited remaining capacity to serve new demand, whereas another may have plentiful capacity to accommodate it (perhaps because it is a generation-dominated part of the network). More granular charges should provide better signals to users that incentivise more efficient use of available network capacity.

3.16. There is a broader need to minimise distortions in the DUoS charging regime with respect to treatment of generation and demand. This includes making sure that demand, onsite generation ("behind-the-meter") and distribution-connected generation are all treated appropriately under DUoS, reflecting how they drive network costs or could help reduce them. Treating generation and demand more symmetrically (as appropriate given, for example, network planning considerations) could help to eliminate discrepancies and signal the value of increased demand in some areas, as well as decreased generation.

3.17. In considering any changes, we recognise that **predictability of charges** is important for users and can help ensure that signals are effective in bringing about behavioural change. This is a key driver for our decision to review EDCM charges, which can send signals to Extra-High Voltage users that are volatile and hard to predict. This may undermine the influence of distribution network charges on the planning and operational decisions made by these users which could minimise costs.

3.18. We recognise that sufficiently predictable charges are important to network users. We emphasise, however, the distinction between predictability and volatility, as it is possible for a volatile signal to be sufficiently predictable that users can alter their behaviour and plan accordingly.

3.19. We have modified our consultation position to make clear that we are not solely focused on predictability of charges for Extra-High Voltage connected users. We agree with respondents who suggested that there is a case for considering changes to improve the consistency of methodologies used for EDCM charges (reflecting the fact that there are two different methodologies used at the discretion of each DNO according to network area).

3.20. There are **inconsistencies between current approaches** which mean the charges for all Extra-High Voltage network users are not equitably determined under the Long Run Incremental Cost (LRIC) and Forward Cost Pricing (FCP) methodologies. This results in differences in predictability and cost-reflectivity which we will consider in the review. Moving to a more consistent approach to how the network is assessed may be able to improve predictability without undermining cost-reflectivity. Better consideration of the spare capacity available on the network could also be an area for improvement across the charging models.

3.21. Overall, our aim will be to consider improvements to locational charging signals with a priority focus on cost-reflectivity, consistency and predictability. In considering any changes, we will review whether the combined signal of use of system charges and connection charges will be sufficiently effective in influencing investment decisions.

3.22. As part of reviewing the potential changes to charges across distribution voltage levels, we will consider the extent to which alignment of locational methodologies across all voltages could be beneficial (including alignment with the approach at transmission). We will also consider arrangements for Independent Distribution Network Operators (IDNOs) in developing the proposals.

3.23. We recognise that there may be limits to how far it is feasible and desirable to establish greater granularity of charges. For example, we know that availability of network data needed to inform more accurate locational charges may be limited at lower voltages. We intend to explore this further through the course of the SCR.

3.24. In respect of small users, we have explained in section 2 of this document why we think it is important to consider changes that better signal how small users can contribute to or reduce network costs. As part of the review, we will consider options to mitigate potential adverse impacts of our reforms on small users, in particular for those in vulnerable situations. We think that a charging threshold below which signals are not as sharp could be one way of achieving this. As we discuss in section 2, we intend to carefully consider the feasibility and desirability of setting such a threshold given the challenges associated with it, alongside other options for protection, in particular for consumers in vulnerable situations.

3.25. When considered together with other areas of the SCR, we think that a focus on changes to these aspects of DUoS could improve cost-reflectivity and stimulate more efficient behaviour in current and future network users. This should result in more efficient use of network capacity whilst reflecting the fact that electricity is an essential service. Robust, sufficiently granular and predictable locational signals are an important aspect of the review and a key incentive for network users to optimise their behaviour in accordance with network cost drivers.

3.26. We acknowledge that change can create uncertainty. However, we believe that the defects in the current arrangements are sufficiently extensive that a wide-ranging review is necessary. The majority of respondents supported this view.

3.27. .We also note that the need for changes to these network charges has been widely acknowledged for a considerable time, and we have referred to it in numerous previous documents. We hope that transparency and engagement with stakeholders on our guiding principles and thinking during this review will help all market participants, including investors, to anticipate and plan for reforms to these arrangements.

Review of the connection charging boundary

Consultation position and feedback received

3.28. In our consultation, we proposed to include a review of the distribution connection charging boundary if distribution use of system charges can be made more cost-reflective, but not to review the transmission connection charging boundary. The depth of a connection boundary refers to the costs incurred by a connectee in cases where reinforcement[18] of the network is required (as opposed to the costs borne by a wider set of consumers through ongoing use of system charges).

3.29. Moving the current 'shallow-ish'[19] distribution connection boundary to a shallow[20] basis would be dependent on better locational signals being sent through ongoing distribution use of system charges. This would result in some costs (eg reinforcement costs) being reflected in ongoing network charges rather than connection charges. One respondent suggested that connection charges provide better signals than ongoing locational charges, citing the conclusions of the most recent EDCM review.

3.30. Alongside considering a shallower distribution connection charging boundary, we proposed that we would also consider implementing financial commitment arrangements at distribution, to reduce the risk to wider users and consumers in general of disconnections and subsequent stranded assets. Most respondents supported this, but highlighted the risk that user commitment arrangements create a barrier to entry.

3.31. Respondents largely supported the distribution connection boundary being included in the review, with the arrangements at transmission being excluded. They cited the barriers to entry and efficient investment in the network caused by the current arrangements, as outlined in the July consultation.

3.32. Some respondents said that the treatment of existing users who have paid for reinforcement through their connection charges would be important.

[18] Reinforcement is the installation of assets to add capacity to the existing network.
[19] Under a shallow-ish connection boundary: - The connection customer will pay for their own sole-use connection assets and will contribute towards any resulting network reinforcement required up to one voltage level above that at which they are connecting. This is in contrast to a deep connection boundary where the connection customer would pay for all network reinforcement costs required.
[20] Under a shallow connection boundary, the connection customer pays for their own sole-use connection assets, and the reinforcement of any "shared-use" assets is paid for by use of system charges.

3.33. A small minority of respondents suggested that transmission arrangements should be reviewed to ensure consistency across transmission and distribution.

3.34. One respondent said that changes to the connection boundary would require changes to primary legislation (Electricity Act 1989) as it currently permits electricity distribution companies to charge for the reasonable costs of providing a connection.

Decision

3.35. We confirm that the distribution connection charging boundary is included as part of the SCR, while the transmission connection charging boundary is excluded from the SCR and wider review.

3.36. Any decision to make changes to the distribution boundary will depend on the extent to which we consider that other changes in this review, in particular improved locational signals through DUoS, will offset any risks to consumers. As part of this, we will consider whether the signals provided will be sufficiently effective in influencing investment decisions. This includes the importance of transparency and predictability of use of system charges in providing a signal that can be factored into upfront investment decisions.

3.37. We will explore a range of options. This includes considering the depth of the distribution connection boundary (eg from shallow-ish to shallow), whether different arrangements should apply to different user types (eg those at different voltages) and whether to introduce user commitment arrangements.[21] As part of this work will consider the impact on network users and whether legislative change is required. Our wide ranging review of distribution network charges will consider the impact of introducing more locational network charges.

3.38. We will consider the treatment of existing users who have paid for reinforcement through their distribution connection charges as part of our review. However, we note that ongoing distribution charges have been lower as a result of the shallowish boundary and payments towards reinforcements through the shallowish distribution charges have been modest to date.

3.39. In addition to DNO network users, we will also consider the treatment of existing and future users connected to IDNO networks.

Reasons

3.40. We think the current arrangements at the distribution level may create a barrier to entry and efficient investment in the networks, by targeting a proportion of reinforcement costs on the last party that is deemed to trigger the reinforcement. The majority of respondents supported us reviewing the distribution connection charging boundary.

[21] While these elements will be explored through the review, changes will be proposed only if we identify that there are benefits to doing so.

3.41. If we made this change alongside more locationally accurate DUoS charges, this would mean that existing users also face more accurate incentives to provide flexibility to offset the need for reinforcement. It could also help support more efficient investment in new network capacity by allowing DNOs to factor in demand for capacity from a wider group of network users. In contrast, under a shallow-ish connection charge, some of the costs of reinforcing the network are focused on a particular new user looking for connection. This can be prohibitively expensive for them to take forward, meaning that new network capacity isn't taken forward even where there might be wider demand for it.

3.42. We do not think these issues are replicated in the transmission arrangements, where there is a shallow connection boundary and strong locational signals. We also did not receive further evidence as part of the consultation to justify including the transmission connection charging boundary arrangements as part of this SCR – for example, evidence that the transmission connection boundary was creating a barrier to entry.

3.43. In terms of whether a change to the distribution connection boundary would require legislative amendment, we will consider this further in the course of the SCR. We note that changes have been introduced previously to make the distribution connection boundary shallower.[22]

Transmission Use of System charges

3.44. Transmission network charges, also known as Transmission Use of System (TNUoS) charges, consist of forward-looking charges and residual charges. In this document, references to TNUoS charges are a reference to the forward-looking element of TNUoS, unless otherwise stated.[23]

Consultation position and feedback received

3.45. In our consultation, we proposed a focused review of forward-looking TNUoS charges, rather than a wide-ranging review as we proposed for forward-looking DUoS charges.

3.46. We proposed that the scope of the review should focus on the design of TNUoS charges for small distributed generation[24] and asked whether this should be aligned with the charging arrangements for larger generation, rather than

[22] Ofgem's previous decision to change the distribution connection charging boundary from deep to 'shallow-ish' is here.
[23] Under the current charging arrangements several of the forward-looking charges are subsequently adjusted by scaling the charges up (or down) by the residual charges. The focus of this review is the forward-looking charges. The residual charges are the subject of a separate review, called the Targeted Charging Review (TCR).
[24] Small distributed generators are generators that are connected to the distribution network with a maximum generation exporting capacity less than 100MW. This includes onsite generation that is exporting onto the network.

generally being treated as 'negative demand'.[25] We stated that aligning the transmission charging arrangements for small distributed generation with larger generators would ensure that all directly connected generators face the same forward-looking TNUoS charges.[26]

3.47. We considered this would mean that small distributed generation would receive transmission credits in zones where they are expected to reduce long term transmission costs, and pay transmission charges in zones where they are expected to increase long term costs. We considered this would promote greater cost reflectivity in the charges, reduce distortions to competition between generators connecting at different network locations, and support more efficient whole system outcomes.

3.48. We also asked whether the review should include the design of forward-looking TNUoS charges for demand users. "Triad" charges are based on a user's average gross consumption[27] during three peak half hour periods between November and February. The three periods must be separated by at least 10 days. While the current Triad approach had been effective at eliciting demand response, we noted that the Triad periods were becoming an increasing source of uncertainty and may not always align with periods of peak network constraints in particular areas.

3.49. We did not propose to review the Transport Model[28] methodology used for setting forward-looking TNUoS locational charges.[29]

3.50. Our reasons for a more focused review were that the methodology to set forward-looking TNUoS charges had been recently reviewed through Project Transmit, and that Baringa's work and our own analysis had not identified a strong need to review wider elements of transmission network charging.

3.51. A majority of respondents that have expressed an opinion agreed with reviewing the TNUoS charging arrangements for small distributed generators, and around one quarter did not agree.[30] Of those respondents who did not agree, some suggested we had not established the case that increased distributed generation was contributing to increased transmission costs.

3.52. There was widespread support among respondents for reviewing the forward-looking TNUoS charging design for demand users. Some respondents noted that parties had invested based on the current arrangements and were concerned that changes could increase investment risk.

[25] 'Negative demand' means that generation output is assumed to offset demand and reduce costs on the network - receiving credits rather than making payments.
[26] We have subsequently considered that reviewing the TNUoS charges for larger distributed generation would also be necessary to ensure all directly-connected generation face the same forward-looking TNUoS charges, as discussed below.
[27] Gross consumption in the case of Triad arrangements means the net consumption measured at the grid supply point plus exports from directly-connected distributed generation and onsite generation which is exporting onto the grid.
[28] This is the network charging model used to calculate forward-looking TNUoS locational charges, principally the wider locational network charges. It is defined in the Connection and Use of System Code.
[29] We have subsequently considered whether to review the reference node in the Transport Model, as discussed below.
[30] Around one quarter of respondents did not directly answer this question.

3.53. The largest grouping of respondents (a little over two fifths) agreed with our proposal not to conduct a wide-ranging review of forward-looking TNUoS charges, and a little over one fifth sought a wider review of forward-looking TNUoS charges.[31] Those respondents typically agreed with our reasons for conducting a focused review, and also pointed out the difficulties and significant resource burden on Ofgem and industry if a wide-ranging TNUoS charging review was conducted (on top of the wide-ranging DUoS charging review, and review of access rights).

3.54. Of those respondents who considered we should conduct a wider review, some considered that, as a matter of principle, a wide-ranging review of distribution and transmission network charges should be conducted. Other respondents considered the scope of the review scope should be widened to include specific additional elements of the TNUoS charging arrangements which they nominated. These respondents generally had different views on what specific additional element of the TNUoS charging arrangements should be reviewed.

Decision

3.55. We confirm our position to conduct a focused review of the forward-looking TNUoS charging arrangements. This will include the priority areas of:

- Reviewing **aligning the TNUoS charging arrangements for distributed generation with that of larger generation.**
- Reviewing the **design of forward-looking TNUoS charges for demand users.**

3.56. In the consultation document, we had not formed a view yet on whether to include the design of TNUoS charges for demand users within the review, and sought feedback from respondents on this matter. Having considered the submissions from respondents, we have now decided to include this aspect within the review

3.57. We have also decided to include in the review one other area:

- The **"reference node" used in the Transport model that derives the TNUoS locational charges for different users and areas.**

3.58. In the consultation document, we did not propose to include the Transport Model within this review. Upon considering responses and further analysis, we have now decided to include the reference node, which is a component of the Transport Model, within the SCR scope. At this point, we do not consider this area as a priority for change, but we will review the materiality of these matters and are prepared to take action during the SCR if evidence emerges to support this. We do not intend to conduct a wider review of the Transport Model or a wider review of other aspects of the current forward-looking TNUoS charging

[31] Around one third of respondents did not directly answer this question.

arrangements. If new evidence emerges during the review, we will consider whether changes to the scope of the review are merited.

Reasons

Charges for distributed generation

3.59. Distributed generation can contribute towards transmission network costs in some locations, and reduce transmission network costs in others. At present, the current forward looking TNUoS charging arrangements for transmission connected and larger distributed generation reflect these locational costs differences, because they face locational charges. However, the charging arrangements for small distributed generation[32] do not fully reflect these cost differences.

3.60. There are also some differences between the current TNUoS charging arrangements for transmission connected generation and larger distribution generation. Both face the wider locational charges,[33] whereas only transmission connected generation faces the local locational charges.[34] In our July consultation, we emphasised reviewing the TNUoS charges for small distributed generation, with a view towards aligning these arrangements with that of larger generation. We have now also decided to review the TNUoS charges for larger distributed generation, with a review towards aligning the areas where these arrangements are not already aligned with that of transmission connected generation, namely, with respect to local locational charges. This is consistent with our intent, both in our July consultation and now, which has been to review whether all directly connected generators should face the same forward-looking TNUoS charging arrangements.

3.61. The remainder of this section focuses largely on the charging arrangements for small distributed generation.

3.62. Small distributed generation are treated as negative demand for their forward-looking TNUoS charges, with those charges levied on a Triad basis. This means small distributed generation located in areas where they reduce network costs receive a credit (called an "Embedded Export Tariff"). To prevent a perverse incentive for small distributed generation to lower their generation output at peak times, this credit is "floored at zero", meaning even where small distributed generation are driving additional costs on the network, they do not face these charges.

[32] Small distributed generators are generators that are connected to the distribution network with a maximum generation export ng capacity less than 100MW. This includes onsite generation that is exporting onto the network.
[33] The wider locational charges represent the cost (or savings) of electricity being added to the transmission system in different geographical zones.
[34] Specifically, distributed generators who do not have a Bilateral Embedded Generation Agreement do not face local locational charges. The local locational charges are comprised of a local circuit charge, a local substation charge, plus in the case of offshore generation, an embedded transmission use of system (ETUoS) charge. The local circuit charge reflects the cost of the local assets used to connect generators to the wider network (known as the Main Interconnected Transmission System (MITS), and is payable if the generator is not connected to the MITS. The location substation charge is payable based on the first substation the generator is connected to. The ETUoS charge is faced only by offshore generators connected via DNOs only.

3.63. The growth in distributed generation is not only located in areas with increasing demand. Increasingly there are exports from distribution to the transmission network which are contributing to transmission-level constraints. However, even where grid supply points[35] are not exporting on to the transmission network, distributed generation can still increase transmission network costs. This is because, if the increased distributed generation is displacing existing transmission generation from serving local demand, generation output in that location now has further to flow on the transmission network to find demand, or alternatively may be paid to be constrained off.

3.64. As stated above, distributed generation can increase transmission network costs in some locations, and reduce costs in other locations. In locations where the growth in distributed generation leads to increased costs, that growth has the potential to manifest itself in transmission level costs in one or both of two ways:

- increased transmission network capacity to accommodate the increased distributed generation exports, or
- increased costs of operating the transmission system securely, through increased constraint payments to transmission-connected and larger distributed generators who are constrained off through the balancing mechanism

3.65. The network planning standards are referred to as the Security and Quality of Supply Standard (SQSS). The SQSS outlines the investment needed to properly accommodate demand and generation. Originally this was focused on meeting peak demand conditions. However, reforms through Project TransmiT changed this, and investment is now driven by both the need to provide peak security, and the need to make an economic trade-off between constraint and investment costs.[36] Further changes have been made through a recent modification[37] to ensure that the impact of smaller distributed generation is adequately represented in transmission network planning studies, such that the system can be designed to provide an appropriate level of capacity.

3.66. A current example of distributed generation potentially causing the need for new investment in transmission network capacity is a proposed new subsea link to Orkney. This is a new approximately £260m electricity transmission investment proposed by Scottish Hydro Electric Transmission (SHE-T) to connect the Orkney islands to the Scottish mainland. SHE-T considers that this project is required to allow pre-dominantly distribution-connected wind generators currently developing projects on Orkney to connect in the early to mid-2020s. We have just published a consultation on the need for this project.[38]

3.67. The following two charts show the current forward-looking TNUoS charges (for 2018-19) between transmission-connected and larger distribution-connected

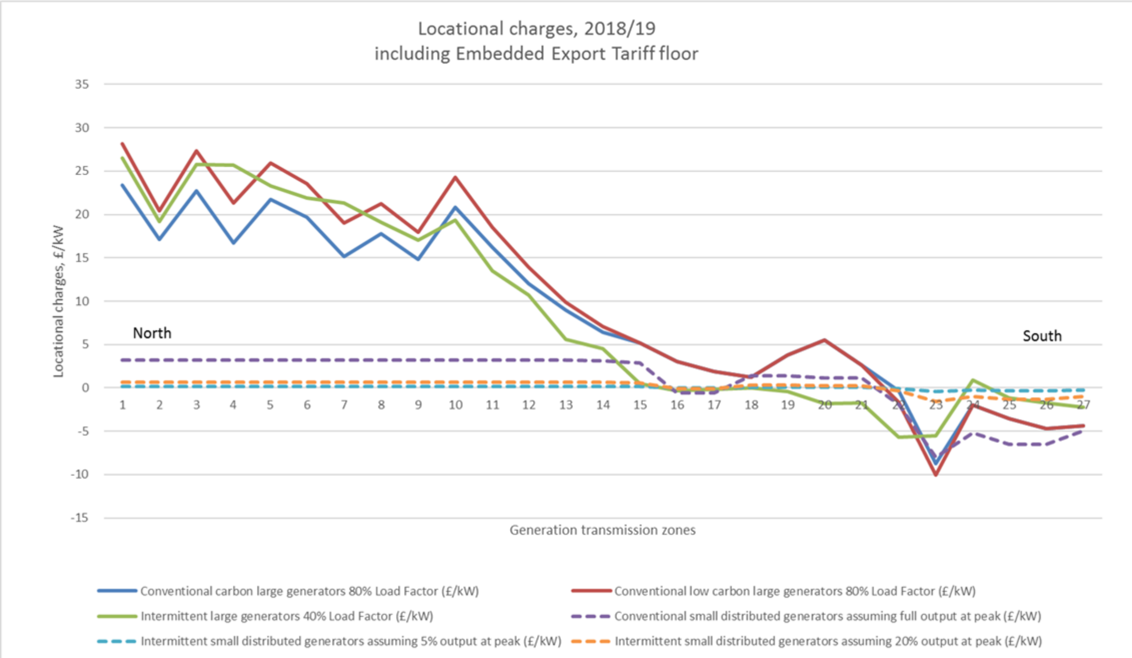
[35] A grid supply points is a system connection point at which the transmission system is connected to the distribution system.
[36] Project TransmiT, link here
[37] GSR016: Small and Medium Embedded Generation Assumptions, see link to our decision on this here.
[38] Ofgem consultation on Orkney transmission project final needs case, link here

generation on the one hand (referred to as large generators) and small distributed generation. The first chart includes the current Embedded Export Tariff floor, and second chart estimates the impact of charges if this floor was removed.[39]

3.68. We consider that the analysis presented in the charts provide evidence of distortions in the current transmission generation charging arrangements. In the north of Great Britain, the current charges for small distributed generation are significantly lower than the charges for larger connected generation[40]. This means the current arrangements are creating a distortion of incentivising excess small distributed generation in the north, or distributed generation which is inefficiently small.

[39] Values for larger generation are based on National Grid's calculated values for conventional carbon and conventional low carbon categories with assumed Annual Load Factor (ALF) of 80%, and intermittent generation with ALF of 40%. These values exclude residual charges and local asset charges.
Values for small distributed generation are calculated using the locational demand tariffs, for the demand zone that is best matched to the relevant generation zone. The charge for small distributed generation depends on the assumed output during Triad periods. We assume output at maximum capacity for conventional smaller generation. For intermittent smaller generation, two assumptions for output at peak are shown – 5% and 20%.
In the second chart, these tariffs are the locational demand tariff only. In the first chart, they represent the outcome if the total tariff cannot be charged to smaller generators, which is the case with the current Embedded Export Tariff. We exclude the impact of the Avoided Grid Infrastructure Cost, which is a credit that all distributed generation receive. Therefore, the effective highest demand tariff that a small distributed generator can pay is £3.22/kW, that will result in zero overall.
[40] The charts show how charges for conventional and intermittent generators vary. It is important to compare-like for like, ie compare intermittent distributed generation with intermittent transmission-connected generation, and the same for conventional generation. To provide these charts we have made some illustrative assumptions about the different generations' load factors and peak output.

Figure 1: Current wider transmission generation forward-looking charges by generation zone (includes Embedded Export Floor)[41]

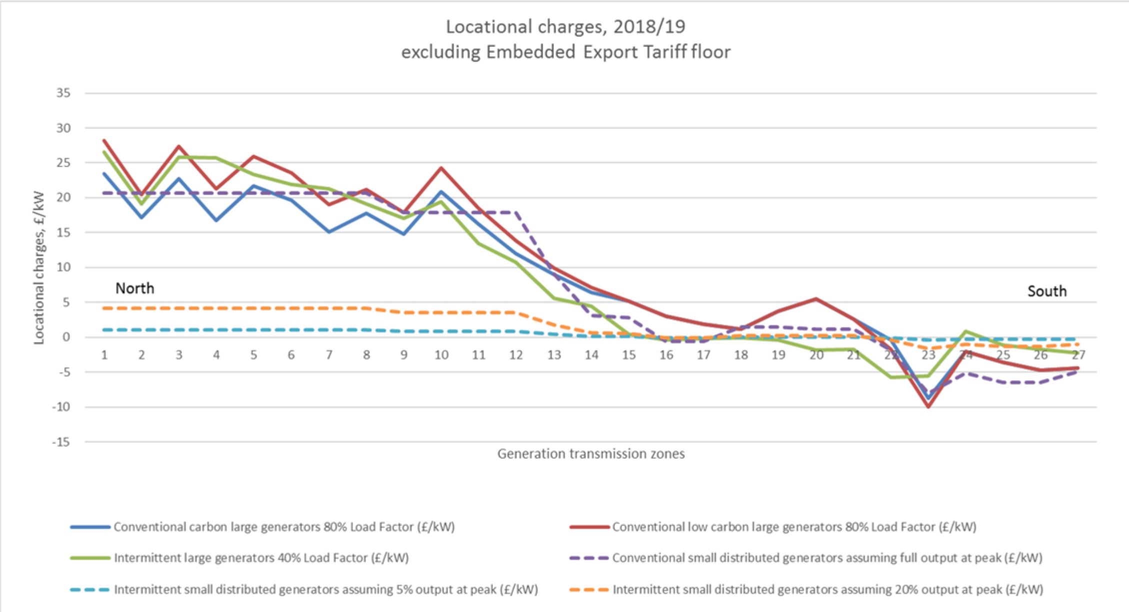


Source: National Grid final TNUoS tariffs 2018/19, Ofgem analysis

3.69. Removing the floor on the Embedded Export Tariff, as shown in Figure 2, would remove a significant source of the differences between the charges for small conventional distributed generation and larger generation charges. However, this would leave significant differences between the charges for small intermitted distributed generation. Furthermore, the current Embedded Export Tariff floor was introduced to remove the disincentive for distributed generation to export during peak times. We consider aligning the forward-looking TNUoS charging arrangements for small distributed generation with the current arrangements for larger generation, would mean that these forms of generation faced consistent charging signals. This would also mean the current Embedded Export Tariff floor could be removed.

[41] In the charts, the solid lines represent the charges for larger generation and the dashed lines represent the charges for small distributed generation. The solid red and blue lines show the charges for conventional carbon and low carbon technologies respectively with an 80% maximum output, whereas the green line represents the intermittent large generation charges with a 40% load factor. These load factor assumptions reflect the standard assumptions made by National Grid for illustrative purposes. The solid purple line shows the charges conventional small distributed generation with 100% output at peak. The remaining dashed turquoise and orange lines present the different ranges of output for intermittent smaller distributed generation which we have modelled at 5% and 20% respectively, for sensitivity purposes, given the lack of a clear reference point for these assumptions.

Figure 2: Estimated current transmission generation forward looking charges by generation zone (if Embedded Export Floor was removed)



Source: National Grid final TNUoS tariffs 2018/19, Ofgem analysis

3.70. Equally, there is also a need to consider whether the current transmission charging arrangements create significant distortions either against or in favour of onsite generation compared to directly connected generation. The charges (or credits) for onsite generation can occur via both the generation charges if it is exporting onto the system and through changes to demand charges if not exporting. For onsite generation which is not exported onto the network, it may remain appropriate for this to be treated consistently with changes to demand. We discuss the demand charges in the next section.

3.71. In general, there is a growing level of competition now between different types of generation and demand and this means there is an increasing importance in ensuring that regulatory differences in network charging are not distorting outcomes in a significant or material way.

3.72. In line with our principles for this review, we intend to weigh up the economic efficiency benefits of removing these distortions, with an assessment of the proportionally and practical considerations of any changes.

<u>Charges for demand users</u>

3.73. In response to the consultation document, there was widespread support from respondents for including the design of forward-looking TNUoS charges for demand users within the review. We agree with respondents, and have decided to include this matter within the scope of the SCR. As noted above, the current design of transmission charges for demand users who are half-hourly settled, which means mostly large users, is based on arrangements referred to as Triad.

3.74. Triad has been successful in eliciting demand response from users during Triad periods, which are intended to reflected times of system peak demand. However, we consider there are three potential issues with the current Triad arrangements for forward-looking charges[42]-

- The timing of Triad periods is increasingly creating uncertainty.
- The Triad periods may not always align with periods of peak network constraints in particular areas.
- It may cause distortions between directly connected and onsite generation due to the differing charging arrangements.

3.75. Transmission charges for demand users are based on usage during only three peak periods, which are not known in advance, and changes in the patterns of these times make them hard to predict. We have heard an argument that the uncertainty is a positive attribute, as it means users increase the number of days when they engage in demand management (as they are less certain when Triad periods will fall). However, it also creates significant costs for industry as they seek to predict when the Triad periods will be. We consider there may be alternative ways to promote demand management which provides more certainty to users and better aligns with network costs.

3.76. Under Triad, demand is charged based on peak demand during winter. This is based on the fact that the level of demand during these periods was the key driver of network costs as the network was most constrained during these times. As the energy system is changing we know that constraints are happening at different periods – for example sometimes during periods of lowest demand in the summer – and so we think there is a need to consider whether the Triad periods continue to be appropriate.

3.77. Our current view is that onsite generation which exports onto the networks has a similar effect on network usage as directly-connected generation, and should be treated consistently as appropriate (including taking account of materiality and relevant differences). However, the situation with non-exporting generation is less straightforward. This is currently treated as variation in demand and hence faces the inverse (or opposite) of demand charges. From the perspective of network usage, this treatment may not be problematic. We plan to consider these issues further during the review.

3.78. Reviewing the design of transmission network charges for demand users (including demand users with onsite generation) allows for consideration of moving towards a more capacity-based approach to demand charging, and whether there are distortions between the charging of directly connected and onsite generation that need addressing.

[42] The use of the Triad approach for residual charges raises other problems, and is being separately reviewed through the Targeted Charging Review (TCR).

Reference node within Transport Model

3.79. The Transport Model calculates the incremental cost of transmission from and to different areas, and this cost is reflected in the demand and generation forward looking charges. It does this by modelling the transmission system as over 900 "nodes" (basically, junctions where different parts of the system meet) which are connected by over 1400 "circuits" (transmission lines or cables that carry power), and modelling how an additional injection of power at each node would flow to a "reference node". The current approach to defining the "reference node", is referred to as the "demand weighted distributed" approach. The effect of the approach is that demand users, in aggregate, contribute approximately zero revenue from the locational charges. Generators, in aggregate, contribute a positive amount of revenue from the locational charges.

3.80. While we do not see this matter as a definite priority area, unlike the areas above, there are two potential problems with the current approach we intend to review and assess the materiality of. The two issues are (other issues may appear over the course of the review):

- *Likelihood of breaching the €2.50/MWh cap*—The €2.50/MWh cap is the maximum level for annual average transmission charges paid by generators.[43] Changes we could make as part of this review – such as deciding that small distributed generation should face the same transmission charging arrangements as larger generation could impact on average transmission generation charges. We will assess whether this potential change could mean there is a greater likelihood of charges breaching the €2.50/MWh cap. Changes to the reference node might reduce average TNUoS generation charges and therefore reduce the risk of breaching the cap.

- *Reducing distortions between different types of generation*—Part of our case for reform is levelling the playing field between different users, including different forms of generation. The current choice of reference node may create distortions between different providers of energy services. In particular, by having a positive average charge in relation to wider transmission costs for generators, and approximately zero average charges for demand users could cause distortions between different types of generation (for example, between generators connected at different locations, or between onsite and directly-connected generation) This could distort competition and lead to inefficient investment decisions. We intend to review the extent of these potential distortions

3.81. If the evidence suggests that either or both of these matters are material, an option for improvement to some of these matters could be to shift the reference node so that it collected less revenue, in aggregate, from generation users.

3.82. One respondent suggested that the reference node should be looked at, but considered that any work to change it could be undertaken independently outside

[43] Commission Regulation (EU) No 838/2010 of September 2010 prescribes permissible ranges for the 'annual average transmission charges' paid by producers (generators) in the EU Member States. The annual average transmission charge for each Member State is defined to be equal to the total transmission tariff charges paid by generators in that Member State in a given year, divided by the total output of those generators in that year. For Great Britain, the cap is set at €2.50/MWh.

the SCR. For the reasons outlined above, we have decided to include the reference node within the scope of the SCR.

A wider review of forward-looking transmission network charges

3.83. As noted above, in the consultation document we proposed a focused review of transmission network forward-looking charges. This was because this area had been reviewed in recent years through Project TransmiT, and that Baringa's work and our own analysis had not identified a strong need to review wider elements of transmission network charging.

3.84. Of those respondents who suggested we should conduct a wider review, some of these respondents did not identify specific problems with the current arrangements. Instead, their rationale was that as we had proposed a wide-ranging distribution network charging review, that as a matter of principle, we should conduct a transmission network charging review of similar depth. We are not satisfied that this, in itself, is a strong enough reason to conduct a wide-ranging transmission network charging review, especially taking into account the resource implications of such a review on both us and the industry. We consider that across access rights and network charging, we have appropriately identified and prioritised the most important topics for review.

3.85. Of those respondents who identified specific additional elements of the transmission network charging arrangements for review, those respondents generally did not identify the same elements as other respondents. The disparate nature of the additional elements nominated by respondents provides us with a level of comfort that the areas we identified for review aligns with the areas the industry, taken as a whole, also sees as the priority areas. We also consider that most of these elements have a lower inter-relationship with other elements within our proposed SCR scope. This lower interrelationship means there is less reason to include these elements within the SCR scope, because the benefits of reviewing these elements at the same times as the rest of the SCR is lower. We have considered these additional elements but we have decided not to include these elements within the SCR scope.

3.86. A small number of respondents raised related matters around seeking clarity on the application of the €2.50/MWh cap on generation charges going forward, in light of Brexit, our Targeted Charging Review, and our decision on the industry code modification CMP261 (which stated that most, if not all, local assets required to connect a generator to the MITS, like connection assets, should be excluded from the application of the cap). On those matters:

- In the absence of specific information to the contrary, our working assumption is that the €2.50/MWh cap on generation charges will continue into the foreseeable future.

- Our interpretation of the "connection exclusion" within our decision to reject CMP261 will necessitate a code modification.[44] The ESO is developing an industry code modification which would enact this interpretation of Commission Regulation (EU) No 838/2010. This would allow us to direct that our policy position, as currently set out in our TCR minded-to decision, of removing residual charges on generation is met.[45]

- We also note current negative residual charges act as a balancing item to ensure average generation charges remain within the cap. This is related to our decision above to include the reference node within the scope of the SCR

3.87. A small number of respondents raised related matters around that the current Investment Cost Related Pricing (ICRP) approach produces a relative price differential across GB. They contended that charges should reflect absolute costs, or that Ofgem should review all the power flow approaches (ICRP; Forward Cost Pricing and Long Run Incremental Cost) to determine the most appropriate approach going forward. We intend to consider the relative merits of different power flow approaches within our wide-ranging review of forward-looking DUoS charges. If, as a consequence of this review, changes to the transmission approach appear to be warranted, this could be considered later.

3.88. One respondent expressed a view that interconnectors currently do not pay transmission charges, and this should be reviewed as part of the SCR. In implementing the Third Energy Package, we approved changes to remove network charges from interconnectors and so this issue is not within the scope of our review.[46]

3.89. One respondent said the zoning criteria used to average locational cost signals and dampening charges should be reviewed, along with the methodology used to determine the forward-looking unit investment costs within the Transport Model. However, no specific evidence was presented on problems with the current arrangements. We note that generation zoning and unit investment cost assumptions are reset at the start of each electricity transmission price control by the Electricity System Operator. We also note that we have considered whether the different number of generation charging zones and demand charging zones may be causing distortions between directly-connected and onsite generators. The materiality of this issue appears to be isolated to specific locations, and reviewing this matter within the scope of the SCR appears to be less of a priority than the other transmission charging areas we have prioritised for review.

[44] Our decision to reject CMP261 can be found here: link here
[45] Our minded to decision can be found in the link here
[46] Ofgem decision on GB ECM-26, see link

Balancing Services Use of System charges

Consultation position and feedback received

3.90. We stated that we were not proposing a review of the socialisation of constraint management costs within Balancing Services Use of System (BSUoS) charges (where costs are ultimately borne by consumers in general) as part of the priority areas of the proposed review. However, we added that there would be value in further work on balancing services charges more generally to consider whether it can provide better forward-looking signals for the different cost elements it recovers.

3.91. We explained that the balancing services charges embedded benefits remain under review as part of the TCR. We also indicated that if balancing services charges (or elements of it) remain a cost recovery charge, then we will consider whether to reform it in line with any reforms to the transmission network and distribution residual charges we may make as part of the TCR.

3.92. We stated that, to help establish the long-term direction for balancing services charges, there was a need for further analysis of whether the different cost elements it recovers could be charged for more cost-reflectively. We invited views on a task force under the Charging Futures arrangements taking this question forward and it being led by the ESO.

Decision and Reasons

3.93. The majority of respondents supported further work on balancing services charges and agreed that it should be ESO-led. Some of those in support highlighted particular issues that they thought should be considered by any review. A minority disagreed with the need for further work. The main reasons were either from a practicality or policy perspective.

3.94. Following consideration of responses on this issue, we decided to ask the ESO to launch a task force under the Charging Futures arrangements.[47] We announced this decision, and our reasons for it, alongside the TCR consultation, on 28 November 2018.[48]

3.95. The objective of the Task Force will be to provide analysis to support decisions on the future direction of balancing services charges. In particular, it will examine the potential and feasibility for some elements of balancing services charges to be made more cost-reflective and hence to provide more effective forward-looking signals. It should consequently identify the extent to which the different elements of balancing services charges should be considered cost-recovery charges and therefore have potential for the TCR approach for cost-recovery charges to be applied. The Task Force should publish its final conclusions in May 2019.

[47] http://www.chargingfutures.com
[48] 'Review of balancing services charges' 28 November 2018; link here

3.96. We will consider the report from the Task Force carefully in the context of this review and the TCR. This will include consideration of the relationship between the findings of the review and any potential changes to the balancing services charges embedded benefits. We expect the conclusions of the Task Force to be available ahead of our final decision on the TCR. Relevant findings of the Task Force will also inform the development of the Access and Forward-looking Charging SCR.