ofgem Making a positive difference for energy consumers

Getting more out of our electricity networks by reforming access and forward-looking charging arrangements

Consultation

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Overview:

Our energy system is currently going through a radical transformation, with new technologies becoming widespread, such as storage, electric vehicles, and heat pumps. We do not think the current approaches to allocating and using capacity – and charging for the associated network usage – on the electricity networks can adequately address the associated challenges and opportunities. We believe there is a strong case for evaluating new arrangements that would ultimately result in lower bills for consumers.

In this document, we set out our views on the key problems with the current arrangements, the options that we should prioritise in addressing these problems, and how this should be taken forward. This includes consulting on launching a Significant Code Review, where we would lead changes, as well as considering the role of industry in taking forward some areas.

We would now like to hear your views on these points. We invite responses to this consultation by 18 September. We will also be discussing these proposals at a Charging Futures Forum on 5 September. If you would like to attend please visit http://www.chargingfutures.com.

This consultation is likely to be of particular interest to system and network operators, generators, flexibility providers, suppliers, larger energy consumers and consumer and local energy representatives.

Context

Ofgem regulates the gas and electricity markets in Great Britain. Our principal objective is to protect the interests of existing and future gas and electricity consumers. We do this in a variety of ways including:

- promoting value for money,
- promoting security of supply and sustainability, for present and future generations of consumers, domestic and industrial users,
- the supervision and development of markets and competition, and,
- regulation and the delivery of government schemes.

One of our roles is to oversee the industry rules for access to the electricity networks and associated network charges. In light of the energy system transformation, we think there are a number of areas where there is a strong case for changing the arrangements for network access and charging in order to deliver greater benefits for consumers.

We launched our work in this area in November 2017 with the publication of 'Reform of electricity network access and forward-looking charges: a working paper'[1]. Since then we have worked with two industry Task Forces under the Charging Futures Forum to consider options for reform. We have reflected the discussions and report of those Task Forces in developing the proposals in this consultation. We are seeking feedback on our views on what needs to be reviewed and how it should be taken forward.

This work is closely related to the Targeted Charging Review (TCR) that is considering changes to the residual electricity network charges. These are used to ensure network owners' allowed revenues are recovered once the forward-looking network charges have been levied. Hence the work discussed in this consultation is being closely coordinated with the ongoing work of the TCR.

[1] https://www.ofgem.gov.uk/publications-and-updates/reform-electricity-network-access-and-forward-looking-charges-working-paper

Associated documents

Documents associated with this consultation are:

1. 'Making the electricity system more flexible and delivering the benefits for consumers', Ofgem, September 2015, available at: https://www.ofgem.gov.uk/publications-and-updates/position-paper-making-electricity-system-more-flexible-and-delivering-benefits-consumers
2. 'Upgrading our Energy System – smart systems and flexibility plan', Ofgem and BEIS, July 2017, available at: https://www.ofgem.gov.uk/publications-and-updates/upgrading-our-energy-system-smart-systems-and-flexibility-plan
3. 'Reform of electricity network access and forward-looking charges: a working paper', Ofgem, November 2017, available at: https://www.ofgem.gov.uk/publications-and-updates/reform-electricity-network-access-and-forward-looking-charges-working-paper
4. 'Assessing the current issues with electricity network access and charging', Baringa Partners LLP, July 2018, available at: https://www.ofgem.gov.uk/publications-and-updates/getting-more-out-our-electricity-networks-through-reforming-access-and-forward-looking-charging-arrangements
5. 'Electricity Network Access & Forward Looking Charges: Final Report and Conclusions', Charging Futures, May 2018, available at: http://www.chargingfutures.com/media/1203/access-and-flc-final-report-and-conclusions.pdf
6. 'Targeted Charging Review: update on approach to reviewing residual charging arrangements', Ofgem, November 2017, available at: https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-update-approach-reviewing-residual-charging-arrangements
7. 'Future Insights paper 5 - Implications of the transition to electric vehicles', Ofgem, July 2018, available at: https://www.ofgem.gov.uk/publications-and-updates/ofgem-s-future-insights-paper-5-implications-transition-electric-vehicles

Contents

Executive Summary

What we want to achieve

Our energy system is undergoing a radical transformation. We are generating and using electricity in different ways, in different locations and at different times. Generation has become more decentralised and is increasingly from variable renewable resources, and the electrification of transport and heat are expected to create significantly more demand. These changes can really benefit consumers but they also put pressure on our electricity networks as capacity becomes constrained in different locations, and can increase costs and delays in connecting to them. It is important that these changes are managed without incurring unnecessary additional costs, and in a way that treats people fairly, particularly those that are less engaged in energy markets or in vulnerable situations.

We think that a critical part of the response to these challenges is ensuring effective:

- **Network access arrangements.** By this we mean users' network access rights and how these rights are allocated. Network access rights define the nature of users' access to the networks – how much they can import or export, when and for how long, where to / from, and how likely their access is to be interrupted and what happens if it is.

- **Forward-looking charging signals.** The elements of network charges that signal to users how their actions can either increase or decrease future network costs in different locations. These charges include the upfront connection costs for connecting to the system and the ongoing forward-looking use-of-system charges.

In this consultation we are inviting feedback on our proposals for which areas of access and forward-looking charging arrangements should be reviewed as a priority, and on how these should be taken forward.

Our aim is to ensure the electricity networks can be used efficiently and flexibly, so that we can each have the access we need and benefit from new technologies and services, while avoiding unnecessary costs on energy bills in general.

The case for change

The energy system transformation is creating a number of opportunities and challenges for the electricity networks. We commissioned consultants Baringa Partners LLP to develop the evidence base on issues to address. Based on this work, we see three top priorities:

1) Enabling growth in demand, particularly stemming from new low carbon technologies, while managing constraints on the networks

Increasing deployment of electric vehicles and heat pumps could lead to network capacity becoming constrained at peak times. This could require substantial investment in new network capacity with a knock-on effect on consumer bills. However, there is also scope for smart and flexible management of technologies such as electric vehicles and heat pumps to move usage away from network peaks, making fuller use of existing network capacity. To achieve this, it will be important that the network access and charging arrangements provide better signals about the costs and benefits of using the network at different times and locations.

2) Managing constraints on the distribution networks as a result of growth in generation connecting there

The rise of distributed generation (DG) means that there are already significant areas of the network that are constrained in how much more electricity these new forms of generation can 'export' onto existing networks. This could lead to the need for investment in new network capacity or delays for new DG projects being able to connect to the network. Current arrangements do not provide sufficiently refined access choices and forward-looking charging signals to DG about the impact of locating at different points on the network, nor a good signal for where investment in new network capacity would be beneficial.

3) An effective interface between transmission and distribution arrangements

The growth in distributed energy resources (DER) – both DG and distribution-connected demand-side resources that can provide services to the system - is increasing the interaction between transmission and distribution networks. The current arrangements for transmission and distribution access and charging have been developed separately and differ in a number of ways. This could distort competition between different sizes and types of project. There are more electricity exports from onsite generation on customer premises onto networks, and also from distribution networks onto the transmission network, affecting transmission-level costs. It is important that the arrangements adequately reflect the impact of distribution-level users on the transmission network.

Baringa did find other areas where there could be further consumer detriment but considered that these were comparatively less significant. We think it is important that the scope of areas to be reviewed is targeted to progress the highest priority areas. We therefore are proposing that the review of some areas could be deferred until a later stage.

Our views on the priority areas to be reviewed

Our proposals for the priority areas for review have been informed by the work of Baringa, the two industry Task Forces that we set up and chaired under the Charging Futures Forum and Ofgem's ongoing work on network connections and charging.

We think there is a need to consider reforms to ensure that capacity is more readily available and meets users' needs better. These include improving the definition and choice of access rights and how rights are allocated and potentially reallocated, including to consider the scope for markets for access.

We also think there is a need to consider reforms to encourage users to use the network at times or places where there is more spare capacity, and so reduce the need for new investment and keep consumer bills as low as possible, and to level the playing field between users. We propose a wide review of distribution charges (covering both connection charges and ongoing use of system charges), and a more focused review of transmission use of system charges.

The review could result in changes for a range of user types. For example:

- For **many small users,** including households, energy is an essential service and network access is non-negotiable for core capacity needs. However, to keep bills for all down we think there is a need to consider options so that users who want to consume a lot more at peak times need to pay the associated additional network charges.
- For **larger users**, those willing to accept less than 'firm', constant access in return could benefit from quicker connection and lower network charges. New arrangements could also allow better allocation and reallocation of capacity, so that those that can bring greater value to the system are better able to get the access they need. Their charges could be based more on the access rights they have chosen rather than their usage, and more accurately reflect how their actions increase or decrease network costs in their particular location. Arrangements could also be more consistent for users connected at different voltages, so that competition between providers of system services is driven by who can create most value for consumers rather than by differences between charging arrangements across different levels of the networks.

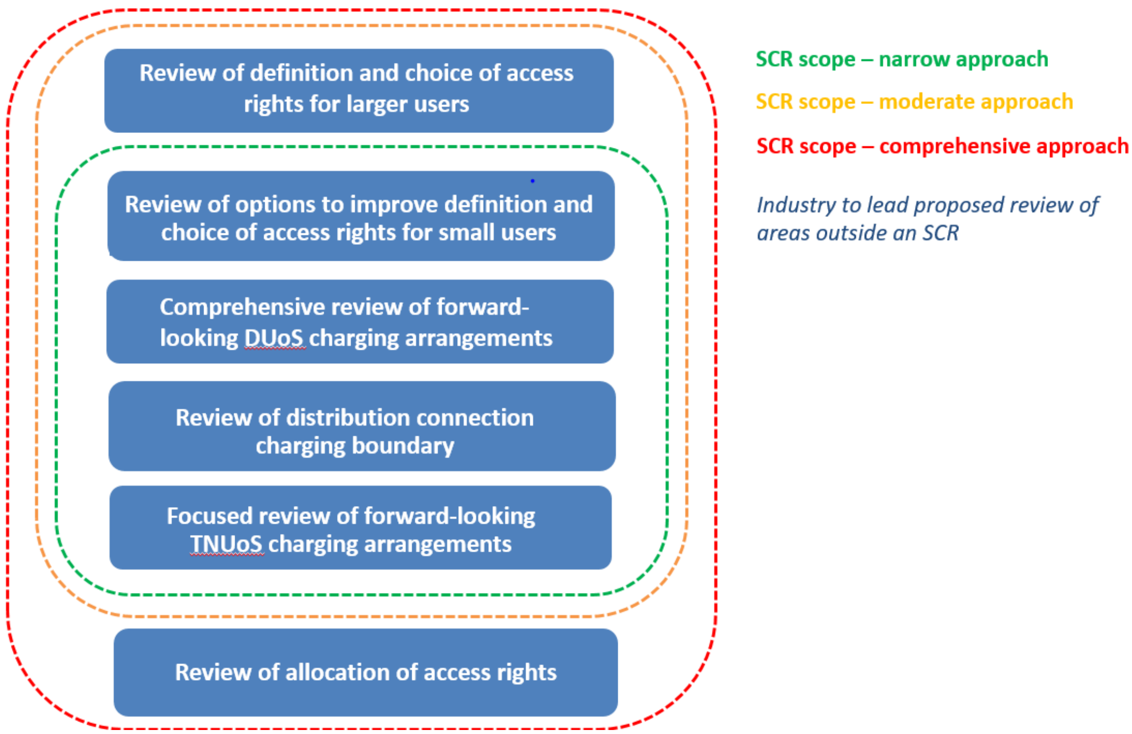
Taking forward the review

Industry, particularly the Electricity System Operator (ESO) and Distribution Network Operators (DNOs), has an important role in developing potential changes. However, at times it is necessary for Ofgem to lead change to ensure timely progress, particularly in more cross-cutting and contentious areas.

We are therefore consulting on launching a Significant Code Review (SCR). The SCR process provides a vehicle for us to initiate wide-ranging and holistic change and to implement reform to code-based issues.

We think there are three broad options for the scope of the SCR: narrow, moderate or comprehensive (see figure 1 below).

Figure 1 – Options for leadership of proposed review



As a minimum, we think an SCR should cover our proposed priority areas of small users' access rights and potential changes to the network charging arrangements. We are inviting views on whether the ESO and DNOs should lead the review of access arrangements for larger users, or whether these should also be in the scope of the SCR. At this stage, we are proposing an SCR where, on conclusion of the SCR phase, we would issue a direction to licensees to develop code modifications that will take forward our conclusions.

For areas where we decide the ESO and DNOs should lead, we are considering new licence obligations on them to ensure they take this work forward in a timely way. We propose to continue using the Charging Futures Forum infrastructure to support delivery and coordination of this work and provide a forum for stakeholder engagement.

Subject to consultation responses, we expect to conclude on whether to launch an SCR by the end of this year. If we do, we would expect to conclude the SCR in late 2020, with potential implementation of some changes from April 2022 and the remainder in April 2023. Industry-led changes on areas outside of the scope of the SCR could be implemented ahead of this.

1. What we are trying to achieve

Chapter Summary
Sets out the objectives of our work in this area and explains the context of the project.

Our objective for this work

1.1. The aim of our work in this area is to keep bills down for consumers by making sure networks are used as efficiently and flexibly as possible, as the energy system decarbonises. Our objective in reforming access and forward-looking charging arrangements is therefore:

To ensure electricity networks are used efficiently and flexibly, so that we can each have the access we need and consumers benefit from new technologies and services, while avoiding unnecessary costs on energy bills in general.

1.2. New low carbon technologies (LCTs)[2], such as EVs, distributed generation (DG), storage and heat pumps are expected to play a key role in meeting our carbon targets, but will make new demands on networks, as well as providing new opportunities (as detailed in our joint plan with the government for a Smart, Flexible Energy System[3]). It is important that these are enabled without incurring unnecessary additional costs and in a way that treats people fairly, particularly those that are less engaged in energy markets or are in vulnerable situations.

1.3. We think that a critical part of the response to these challenges and opportunities is to ensure effective network access arrangements and forward-looking charging arrangements:

[2] LCTs include technologies such as storage, electric vehicles, heat pumps and demand side response. The expected decarbonisation of electricity supplies is critical for some of the technologies to be genuinely low carbon.
[3] 'Upgrading our Energy System – smart systems and flexibility plan', Ofgem and Business Energy Industrial Strategy, July 2017, available at: https://www.ofgem.gov.uk/publications-and-updates/upgrading-our-energy-system-smart-systems-and-flexibility-plan

Network access rights	• The network capacity a user has allocated to them in order to import or export electricity from their target market • Requires a connection from the user's equipment to the wider network, and then **allocated capacity on that wider network**
Forward-looking charges	• The elements of network charges that look to provide signals to users about how their behaviours can increase or reduce future (ie incremental) costs on the network • Includes connection charges and elements of use of system charges

1.4. These arrangements are important as they can encourage users to use the network at times or places where there is more spare capacity. They are key determinants of the extent to which network capacity is available to meet users' needs at an efficient cost.

1.5. There have already been some reforms to these arrangements. For example:

- Distribution Network Operators (DNOs) have introduced the option for flexible connections to provide quicker and more efficient connections in response to the increase in distributed generation.[4]

- our Project TransmiT[5] improved the cost reflectivity of transmission network charges in response to large scale intermittent, largely wind generation, connecting to the transmission network.

- the government introduced Connect and Manage in 2010 to deal with queues on the transmission system and help to achieve carbon reduction and renewables targets.[6]

1.6. However, we believe that there are a number of areas where further reform is needed to improve outcomes for consumers.

[4] https://www.ofgem.gov.uk/system/files/docs/2016/01/quicker_and_more_efficient_connections_jan_2016_-_final_29.01.2016_0.pdf
[5] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit
[6] https://www.ofgem.gov.uk/sites/default/files/docs/monitoring_the_connect_and_manage_electricity_grid_access_regime_sixth_report_from_ofgem_0.pdf

1.7. We think that there are a number of desirable features for access and forward-looking charging arrangements that, if met, will help achieve this objective:

- **Network capacity is allocated in accordance with users' needs**. Often, this will mean capacity should be allocated to those that value it most. This could involve providing choice over access options and making appropriate use of market-based mechanisms where this can drive benefits. However, the need to ensure benefits for society as a whole (see the 7th desirable feature below) means that there will be constraints on the extent to which such market-based mechanisms will be appropriate.

- Network users face **cost-reflective charges** for network access and/or usage, ie their costs (or income) from accessing the network reflect the incremental costs and benefits they confer on the system in both their investment and dispatch decisions. There may be some limits on the extent to which cost-reflectivity is appropriate, for example where ability to respond to signals is limited, and there may be adverse distributional implications (see the 7th desirable feature below).

- Arrangements support competition by providing a **level playing field** across different types of users, technologies or asset types (eg between users looking to connect at different voltages), avoiding undue distortions.

- Forward-looking charges are sufficiently **simple, transparent and predictable** to enable users to make decisions based on them. This includes supporting efficient investment in new energy resources, including LCTs. Some complexity may be needed to support efficient outcomes, but such complexity should have clear value, and we need to consider how this will be manageable for relevant end users.

- Arrangements provide for **appropriate allocation of risks** when developing and allocating network capacity. This means the risks should be allocated to the party best placed to manage them, with network users providing appropriate commitment towards investment they drive.

- Arrangements support **timely and efficient network investment** to meet users' needs by providing high quality information about where and when new network capacity is needed. This includes helping identify where alternative solutions (such as new sources of flexibility) should be taken forward as an alternative to new capacity, where they offer better value.

- Arrangements **reflect that electricity is an essential service**, and take into account the needs of consumers in vulnerable situations.

1.8. We think these 'desirable features' are a useful guide in developing and testing reforms, though there are inherently trade-offs between them that will need to be made. We also consider that any changes will need to be practical and proportionate to the issues they are addressing.

What has been done so far

1.9. This consultation builds on work from the last few years undertaken by us to address the energy system transformation, including our joint plan with the government for a Smart, Flexible Energy System, our Strategy for Regulating the Future Energy System which we published in August 2017 and our ongoing work on network connections and charging as set out in our Forward Work Plans.

1.10. Our Working Paper, Reform of Network Access and Forward-Looking Charges, followed in November 2017[7] and outlined our preliminary thinking in this area.

1.11. Since then, we have set up and chaired two Task Forces composed of a range of industry stakeholders: one on reform to network access and one on forward looking charges. These task forces developed a detailed set of options for reform, and undertook an initial assessment of them. They published a final report with their conclusions and recommendations on the way forward in May[8]. The recommendations of the report, wider engagement through the Charging Futures Forum and other industry work[9] have helped to shape our thinking, and informed the scope and scale of the policy options set out in this consultation.

1.12. In January 2018, we commissioned consultants Baringa to undertake an assessment of the inefficiencies of the current access and forward-looking charging arrangements. Baringa's work is an important element of evidence supporting the case for change (chapter 2).

[7] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/reform-network-access-and-forward-looking-charges
[8] 'Electricity Network Access & Forward Looking Charges: Final Report and Conclusions', Charging Futures, May 2018, available at: http://www.chargingfutures.com/media/1203/access-and-flc-final-report-and-conclusions.pdf
[9] Including other industry charging reports: National Grid's review of transmission charges (https://www.nationalgrid.com/uk/electricity/charging-and-methodology/network-charging-developments-and-charging-futures); and reviews by the Electricity Network Association on the Common Distribution Charging Methodology, Extra high voltage Distribution Charging Methodology, and on differences between transmission and distribution (ENA's reviews are available here: http://www.energynetworks.org/electricity/regulation/distribution-charging/distribution-charging-working-groups.html)

Links to other policies

1.13. The network access and forward-looking charges project has important links with a number of projects being undertaken by us and the industry. We are coordinating our approach and set out the relevant links below:

1.14. This work is closely related to the **Targeted Charging Review (TCR)**.[10] This is considering changes to the residual electricity network charges. These are used to ensure network owners' allowed revenues are recovered once the forward-looking network charges have been levied. The work discussed in this consultation is being closely coordinated with the ongoing work of the TCR.

1.15. We have concerns that the current approach to residual charging is causing significant distortions to behaviour, which could lead to higher bills and unfair outcomes for some consumers. Therefore, we launched the TCR Significant Code Review (SCR) in August 2017. Given the potential size of consumer detriment caused by the current approach to recovering residual charges, we do not think it would be in consumers' interests to wait until we have finalised the review of forward-looking charges to address this issue, but will carefully consider whether transitional arrangements are required. Given the extent of reform required to network charges, we also consider that breaking the work down into manageable packages is sensible. We consider that we can run these projects separately but within the same wider programme. We are making sure that we understand key interactions in policy design, appraisal and implementation across the projects. We will also continue to use the Charging Futures Forum and Charging Delivery Body to ensure consistency, effective coordination and stakeholder engagement.[11]

1.16. We have told the Electricity System Operator (ESO) and DNOs that they need to change how they operate, to encourage better whole system outcomes[12] and improvements in how flexibility services are procured. Progress in this area is being driven forward and coordinated by the **Energy Networks Association (ENA) Open Networks project -** a key industry programme bringing together the system and network operators in a forum focused on changes they need to make given the energy system transformation. Our access and charging reforms could help the market to determine the best use of network capacity and reduce the need for the ESO and DNOs to procure flexibility, or reinforce, to manage network constraints directly. Any mechanisms that might be developed for re-

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[10] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significant-code-review

[11] These two charging forums are discussed further in Chapter 5. More information is available here: http://www.chargingfutures.com/

[12] This was a priority area identified in our joint plan with the government for a Smart, Flexible Energy System. As signalled in the Plan, we are considering where regulatory clarifications or changes may support these outcomes.
https://www.gov.uk/government/publications/upgrading-our-energy-system-smart-systems-and-flexibility-plan

allocation of access might have links with options for flexibility procurement and other flexibility-based market platforms being considered. We will continue to work closely with the ENA Open Networks project in this area.

1.17. In our development of **RIIO-2**[13], the next round of price controls for the ESO and network companies, we will be considering how to get the right incentives for the companies, to maximise the benefit for consumers. This will include considering the incentives for the ESO and network owners to make access available in an efficient manner for the system as a whole, and ensure efficient total system costs by achieving the correct balance between network investment and operational solutions. We will shortly be publishing our RIIO-2 framework decision.

1.18. We will also need to think about how any access and charging reforms may change the scope of what is included in a given sector's price control. This could reflect changes in the amount of investment expected as a result of reforms, or in how investment is recovered. For example, changes to the connection charging boundary at distribution level would affect the allowed revenue which DNOs recover under the price control rather than directly from a connecting customer. Such a change would ideally be aligned with the start of RIIO-ED2. We would aim to signal any such changes in advance so the network companies can consider implications for their plans. Equally, mechanisms and processes can be designed to account for changes during the price control period.

1.19. Several aspects of supply arrangements are currently undergoing review or reform, and we are considering the interactions with potential and charging reforms closely. Notably, these include:

- The introduction of **market-wide half-hourly settlement** (HHS), enabled by smart metering, will expose suppliers to the true cost of supply of their customers and put incentives on them to help their customers shift their consumption to times when electricity is cheaper to generate or transport. This will allow for more cost-reflective network access and charging arrangements for small users, eg charging suppliers more for access at peak, reflecting network constraints, which could help mitigate the need for new network capacity. HHS would be needed to enable a number of options we are considering here and our proposed timescales reflect this link. We recently published a consultation on access to half-hourly electricity consumption data for settlement purposes[14]. This reflects our current thinking on how data could be used for settlement, to maximise its benefit and ensure consumers' privacy

[13] https://www.ofgem.gov.uk/network-regulation-riio-model/network-price-controls-2021-riio-2/what-riio-2-price-control

[14] The consultation, together with an accompanying Data Protection Impact Assessment (DPIA), is available here: https://www.ofgem.gov.uk/publications-and-updates/consultation-access-half-hourly-electricity-data-settlement-purposes. If any of our charging options ultimately required an update to this DPIA or a further DPIA, this would be subject to further consultation.

is safeguarded. Use of this data to calculate transmission and distribution network charges is within the scope of the work underway to develop a Settlement Target Operating Model.

- We recently consulted on the default retail **tariff cap**; a temporary cap for standard variable and default tariffs, introduced by the Domestic Gas and Electricity (Tariff Cap) Bill. We expect the cap to come into force before the end of the year and remain in place until at least 2020, after which we are required to recommend to the Secretary of State for Business Energy and Industrial Strategy whether it should be extended on an annual basis until 2023. We will have to consider how any access or charging options for households may interact with this cap, should it still be in place when any reforms affecting households would be implemented.

- We have also been exploring whether the current **'supplier hub'** retail market design will remain fit-for-purpose into the future. Currently the traditional supplier is the primary intermediary between consumers and the wider energy system. The supplier bills customers for their energy use and is a 'hub' for any transactions with other entities. Notably, the supplier faces network charges associated with the consumers they supply, rather than consumers directly - after the initial connection or increase in capacity, there is typically no direct day-to-day consumer relationship with the DNO. We issued a call for evidence on whether the 'supplier hub' arrangements are fit for purpose late last year. Our response will be published this summer.[15] In reviewing access arrangements, we will consider how various options could apply under different future supply models.

1.20. The **Gas Charging Review (GCR)** is currently ongoing via code modification UNC621.[16] The GCR is looking to reform charging arrangements for transporting gas on the transmission system and ensuring compliance with the EU Tariff Network Code. As we review arrangements for electricity in this project, we are ensuring that we understand lessons from gas access and charging arrangements.

1.21. We have published a number of Future Insights papers that are relevant for our thinking in this project:

- Today we have published our latest **paper on 'Implications of the transition to Electric Vehicles** (EVs). The paper aims to inform the debate on the evolving transport sector, the implications of EVs for consumers and the energy system and some of the policy considerations

[15] More information on the Future Retail Market Design project can be found at: https://www.ofgem.gov.uk/publications-and-updates/future-supply-market-arrangements-call-evidence

[16] We aim to issue a draft impact assessment and consultation on the UNC621 proposals later in 2018, with implementation planned for 2019.

that EVs present. Our proposals to develop better forward-looking charges and improve access choice and definition will allow users to benefit from opportunities presented by EVs and facilitate the development of a more flexible and efficient system. This project is therefore one of the key policy considerations for the rollout of EVs.

- In our **local energy**[17] paper we assessed the local energy landscape, the types of local energy models that are emerging and the potential benefits/risks that they presented to consumers. We are considering options in this project that look to provide effective signals for the value of local energy to networks.

- Our paper on the **decarbonisation of heat**[18] considered the nature of heat demand and supply, outlined the options for decarbonising heat and discussed key impacts of each option. Widespread electrification of heat, such as heat pumps, would significantly increase electricity demand, and network reinforcement could be needed to enable this. We are considering options to help make better use of existing capacity, to help reduce the amount of new investment needed.

1.22. We will continue to monitor developments and look to facilitate the energy system transformation in developing our proposals for access and forward-looking charging reform.

[17] Ofgem Future Insight Series: Local energy in a transforming energy system', link here: Thttps://www.ofgem.gov.uk/publications-and-updates/ofgem-future-insights-series-local-energy-transforming-energy-system

[18] 'Ofgem Future Insights Series: The Decarbonisation of Heat', link here https://www.ofgem.gov.uk/system/files/docs/2016/11/ofgem_future_insights_programme_-_the_decarbonisation_of_heat.pdf

2. Issues with existing arrangements

Chapter Summary
Discusses challenges and opportunities arising from the energy transformation, provides an overview of existing arrangements, sets out the case for change, and illustrates how potential changes may affect different network users and consumers.

➔ **Question 1:** Do you agree with the case for change as set out in this chapter? Please give reasons for your response, and include evidence to support this where possible.

New challenges and opportunities arising from the energy system transformation

2.1. The energy system transformation should create significant benefits for consumers but it is highlighting a number of issues with the current regulatory arrangements that need to be addressed. There are three particular trends that are creating opportunities and challenges that we think need to be addressed through changes to network access and forward-looking charging arrangements to improve outcomes for consumers:

A. Network constraints are becoming increasingly prevalent as the energy system transforms, particularly arising from developments at distribution level. The rise of distributed generation (DG) means that there are already significant areas of the network that are constrained in how much more they can export. The deployment of LCTs such as electric vehicles (EVs) and heat pumps could create real benefits, but may also contribute to network constraints. Enabling these new technologies could require substantial investment if not smartly managed. It is important that where investment could be triggered, those that are contributing to the constraints get adequate signals to change their behaviour to mitigate the risk of unneeded investment and minimise the costs to consumers as a whole.

B. At the same time, the energy system transformation will provide new sources of flexibility, many connected at distribution level, that can enable cheaper active management of network constraints rather than traditional reinforcement. This includes potential flexibility from DG, demand-side response and storage, including from EVs through smart charging and vehicle-to-grid power flows. Modelling by Imperial College/Carbon Trust for the government suggests potential savings of up to £10-13bn cumulatively to 2050.[19] Providers of flexibility need signals about the benefit that they can provide to the network, and

[19]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_anal ysis_of_electricity_flexibility_for_Great_Britain.pdf

network operators need to have sufficient confidence in the provision of flexibility when needed to maintain network stability.

C. The growth in distributed energy resources (DERs) is increasing interaction between transmission and distribution networks. There is also increasing prevalence of exports from distribution networks onto the transmission network, affecting transmission-level costs. There is a need to ensure that there is a sufficiently level playing field between transmission and distribution-level projects, and that the arrangements adequately reflect the impact of distribution-level users on the transmission network (and vice versa).

Overview of existing arrangements

2.2. Network access is typically granted in the process of connecting to the network and can vary in its nature and conditions across the system. Here we provide a brief overview of the current arrangements. A more detailed overview of the current access and charging arrangements can be found in Appendix 3.

2.3. Access to the distribution and transmission networks are defined differently, and vary according to different types of users. These are based on various thresholds:

- For generators' access to the transmission networks: **larger generators' access** is usually explicitly agreed in their 'Transmission Entry Capacity' (TEC), whereas **small distributed generation (DG)'s** access is not well defined[20].
- For demand users' access to the transmission network, they do not have an equivalent of TEC.
- In terms of access to the distribution networks, larger distribution-connected users (both demand and generation) above a certain size typically also have an agreed entry or exit capacity level for the distribution network, whereas most **small users**[21] do not currently have well-defined

[20] By larger generators, we mean those that are connected to the transmission network or those that are connected to the distribution networks and are greater than 100MW. Small DG are those generators connected to the distribution networks that are less than 100MW. Some small DG can agree the ability to export to the transmission system – through a Bilateral Embedded Generator Agreement (BEGA), which provides them with TEC, or may have a Bilateral Embedded Licence exemptible Large power station Agreement (BELLA), as applicable.
[21] By larger distribution-connected users here, we are referring to those distribution-connected users who have an agreed capacity, which is the basis for their DUoS charges. Typically, these users will have current transformer (CT) meters (used for connections above a certain size). Where we refer to 'large users' within this document we are talking about these users and transmission-connected users. While by 'small users' we are talking here about those users

access levels to the network. In practice, most are only limited by their fuse size and may never have considered or 'chosen' the level of access they have.

2.4. Across both the transmission and distribution networks, access is generally provided on a long-term basis.

2.5. Generators with TEC can typically only be curtailed when the generator chooses to do so through the Balancing Mechanism. The ESO will pay generators for doing this when it needs to curtail their output due to transmission constraints. As such, their access rights are said to be 'financially firm'[22] in this respect. DG, in contrast, tends not to be eligible for payment where there are constraints on the distribution network.

2.6. Access is allocated through the connections process, on a first come first served basis. Under 'Connect and Manage' arrangements, generators can connect without the need to wait for wider transmission network reinforcement. The ESO manages the associated constraints predominantly using the Balancing Mechanism, where generators and other flexibility providers are able to submit bids and offers to turn their generation or demand up or down and the ESO selects the most efficient actions to manage the system. DG looking to connect in constrained areas, can generally choose to agree on a 'flexible connection' as an alternative to paying and/or waiting for network reinforcement. Under such an arrangement, DNOs generally have broad scope to curtail their access to manage constraints without the need to agree a payment.

2.7. Connection charges recover the costs of enabling users to connect to the network. All connection charges are site specific. To ensure that the amount paid by each user is fair, all connection charges must be calculated in accordance with a methodology that is approved by Ofgem. There are different connection charging methodologies at transmission and distribution level. At distribution, connection charges are paid before the connection is made live and the connection customer must pay for their own sole-use assets, as well as a proportion of any wider reinforcement (up to one voltage above their point of connection). At transmission, connection charges are paid either upfront, or over a maximum of a 40 year period. The connection charge is "shallower" than at distribution - the cost of wider reinforcements and some sole use assets are recovered via Use of System (UoS) charges).

2.8. UoS charges allow DNOs and TOs to recover their allowed revenue that forms part of their RIIO price control. The forward-looking element of UoS charges

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who are do not have an agreed capacity. These users are typically not CT metered.

[22] 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.

aims to reflect network users' incremental impact on network costs, including current and future investment and reinforcement (that is not recovered through connection charges). There are different models used to calculate UoS charges at different voltages.

- At transmission, generators are charged according to their TEC (with an annual load factor adjustment for part of the charge) and suppliers are charged based on their customers' usage. The amount paid in forward-looking charges is influenced by the location to which that user is connected. The locational charges consist of a wider, zonal charge, and for generators only, a local charge to cover the cost of the local assets that connect them to the wider network (known as the Main Interconnected Transmission System - (MITS)).

- At distribution, the Common Distribution Charging Methodology (CDCM) is used to calculate charges to users who are connected to the Low Voltage (LV) and High Voltage (HV) levels of the network. Charges vary depending on when electricity is used, but do not vary within each DNO area. Generators currently receive credits as default, rather than charges. The Extra High Voltage (EHV) Distribution Charging Methodology (EDCM) is used to calculate site specific charges to users who are connected to the EHV levels of the network and provides locational forward-looking charges according to a power flow model.

- Balancing Services Use of System (BSUoS) charges recover the cost associated with the ESO operating the existing transmission system, including costs for constraints, procurement of system balancing services and operations costs. BSUoS charges are recovered from demand and larger generators based on the amount of energy imported or exported onto the network (£/MWh) within a given half-hourly period. BSUoS charges do not include a locational element.

Why change is needed: the inefficiencies of current arrangements

2.9. We think there are a number of deficiencies in the current arrangements that mean they are not well placed to meet the emerging challenges and opportunities. To build the evidence base for this consultation, we commissioned Baringa Partners LLP to investigate the materiality of potential consumer detriment associated with the current arrangements. Baringa, supported by the CFF Task Forces and Ofgem, identified 22 separate issues relating to capacity allocation, locational signals, inefficient dispatch, signal predictability and cost and risk allocation (see the report 'Assessing the current issues with electricity network access and charging' for further detail on Baringa's approach[23]).

[23] https://www.ofgem.gov.uk/publications-and-updates/getting-more-out-our-electricity-networks-through-reforming-access-and-forward-looking-charging-arrangements

2.10. The breadth of the scope of Baringa's assessment shaped their methodology. Issues were mapped on to impacts in broad categories: transmission, distribution, the interface between them and then by user type (generation/entry or demand/exit). They subsequently undertook a high level qualitative and (where possible) quantitative assessment of issues according to deployment barriers, efficiency of operations, efficiency of investment, and allocation of risk. Using a materiality rating framework developed for the project (see Appendix 6), they compared the scale of inefficiency across the issues. Their high level conclusions are shown in figure 2 below.

Figure 2: Baringa's conclusions

3. Aligning access and charging between transmission and distribution, and across voltage level boundaries

Impact area		Deployment barriers	Efficiency of operations	Efficiency of investment	Allocation of risk
Tx	Entry	Medium	Low	Medium	Medium
Tx	Exit	Low	Low	Low	Low
Interface		Medium	Low	Medium	Low
Dx	Entry	High	Medium	Medium	Medium
Dx	Exit	High	Low	High	Medium

2. Ensuring that access for distribution connected generation and storage is properly valued and signalled to users

1. Ensuring that access and charging arrangements for households are ready for the uptake of LCTs

Note: Baringa's rating framework is detailed in Appendix 6

Source: Baringa Partners LLP, 2018

2.11. Based on Baringa's work and consistent with our wider assessment we consider there are three key priority areas to be addressed:

Priority area 1: Enabling growth in demand, particularly from new LCTs, while managing constraints on the networks

2.12. The expected electrification of the transport and heat sectors may come at a significant cost, but also represents an opportunity for greater flexibility in the electricity system. These major new demand sources could cause congestion on the network as early at 2025, which could see reinforcement costs of c.£400m (NPV to 2040)[24].

2.13. Many households do not have clearly defined access rights. In practice, most households' access to the system is currently only limited by their fuse size. The DNOs do not design the wider system to accommodate households using up to their fuse size at the same time, because this would be expensive and inefficient. Instead, DNOs take account of the inherent diversity of different users' behaviour to make informed decisions about the amount of network capacity that is required.

2.14. For the current distribution price control, RIIO-ED1, we took the decision to effectively socialise costs associated with reinforcing the wider network to enable the connection of LCTs, for usage within certain limits.[25] We considered that this was a practical decision in the absence of good quality information (eg smart meter data) which could determine where households were contributing to system costs or benefits. However, it means existing households currently receive very limited signals about how their behaviour could create wider costs and benefits for the electricity network.

2.15. High upfront connection charges may be a barrier to connecting new large demand-led developments (such as business parks or public rapid EV charge points). This can often mean developments have little option but to either not proceed or locate to an area that is less desirable for them but where there is spare network capacity. There may be other users in the area who would also value more network capacity but because no single user is willing to trigger the reinforcement then DNOs do not have a firm signal to reinforce their network in response.

Priority area 2: Managing constraints on the distribution networks as a result of growth in distributed energy resources on the distribution networks

2.16. In parts of the network, DG is already driving constraints and network costs on both the distribution and transmission network. There is now 28 GW of distribution connected generation (compared to 75 GW at transmission), potentially rising to between 37 GW to 71 GW by 2030[26]. We are already seeing the emergence of large queues to connect (there were 20GW of accepted connection offers (some of which is speculative) in 2016)[27].

[24] These values are very sensitive to EV deployment rates and whether it is clustered or evenly spread geographically.
[25] https://www.ofgem.gov.uk/publications-and-updates/strategy-decision-riio-ed1-overview
[26] The range shown in National Grid's Future Energy Scenarios (FES) 2018
[27] Unlocking the capacity of electricity networks (associated document), Ofgem, February 2017

2.17. For DG, flexible connections are offered by network companies to connect new generation without the benefit of financial firmness. Generators on flexible connections typically face open-ended risk and are curtailed on the basis of pre-defined rules, rather than considering how much they value access at a given time. The lack of an established market mechanism to determine DG curtailment means there is no signal to DNOs about the value to users of new network capacity in real time.

2.18. Flexible connections can free up more capacity on the network. Flexible connections, and other innovative approaches, have so far enabled a 3.7GW[28] of connection offers for DG and can allow quicker or cheaper connections than if they were not available. In their report, Baringa estimate the avoided network reinforcement cost through flexible connections by 2040 could be as high as £1.2bn[29].

2.19. The DUoS charges methodology was not designed primarily with distributed generation in mind, as system demand was the main driver of distribution network cost. In the DUoS methodology, generation is treated as negative demand, and therefore will generally receive a credit rather than a charge. This means that in some areas of the network which are dominated by DG, the DG are receiving benefits through DUoS when in fact they are imposing costs on the network.

2.20. A shallow-ish connection charging boundary may create barriers to entry as costs of reinforcement (up to one voltage above) are focused on new connectees only[30].

Priority area 3: An effective interface between transmission and distribution arrangements

2.21. As noted above, the growth in DER is increasing the interaction between transmission and distribution. This means developers have more choice as to where to site new generation projects. We want developers to respond to signals that reflect the economic reality, not the peculiarities of the regulations. Reviewing and better aligning the access and charging arrangements across both transmission, distribution, and voltage levels will help to achieve this.

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[28] Unlocking the capacity of electricity networks (associated document), Ofgem, February 2017
[29] Based on the NG FES 2017 most optimistic projections of embedded generation capacity. Baringa based their analysis on FES 2017, as it was the most recent projection at the time the analysis was conducted.
[30] Under a shallow-ish connection boundary, the connection customer will pay for their own sole-use connection assets and will contribute towards any wider network reinforcement required. This is in contrast to a deep connection boundary where the connection customer would pay for all wider network reinforcement costs required.

2.22. We are already taking steps to address these distortions in the residual charging arrangements (eg our decision on CMP264 and CMP265 to change electricity transmission charging arrangements for distribution-connected generation[31], as well as the Targeted Charging Review: Significant Code Review (TCR:SCR)). However, there are still differences in the access and forward-looking charging arrangements at distribution and transmission.

2.23. DG does not have 'financially firm' access to the distribution network, whereas this is available at transmission. Further, routes by which DG is able to benefit from financially firm/Connect and Manage at transmission are insufficiently clear.

2.24. The connection charging boundary currently requires distribution connectees to pay a share of any network reinforcement (up to one voltage up), required when connecting, while transmission connectees aren't required to pay through their connection charge. To date, the extent to which DG have paid connection charges reflecting wider reinforcement costs has been very limited, but this could become a bigger issue in the future if distribution networks become increasingly constrained.

2.25. TNUoS charges typically treat small DG differently to larger generators, which means they don't receive the same signals on transmission network. Small DG generally do not pay TNUoS in zones where the transmission connected generation are facing positive charges and they are charged based on their generation during triad periods[32] rather than on a nominated TEC. Additionally, distributed generation do not pay any local UoS charges.

2.26. Currently larger generation is also treated differently to demand in respect to transmission charging, which may be creating distortions. For example, onsite generation is treated as negative demand and charged based on the amount generated during triad periods, whereas larger generation is charged based on their agreed TEC.

2.27. Small DG does not pay BSUoS, in contrast with larger DG and transmission connected generation. We note that currently BSUoS largely functions as a cost recovery rather than forward-looking charge, as the relevant costs are recovered across all larger generators and demand users in each half hour period in a homogeneous manner. Although users can anticipate future BSUoS charges and take action to minimise their exposure to these charges, the costs recovered through BSUoS are not targeted onto those users in a forward-looking cost-reflective manner, and are instead 'socialised' across all relevant users.

[31] https://www.ofgem.gov.uk/publications-and-updates/decision-industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators
[32] Triad periods are the three half-hours of highest demand on the GB electricity transmission system between November and February, and are part of the charging mechanism.

2.28. We are also considering BSUoS as part of our TCR:SCR and there is also currently a substantial code modification proposal (CMP250) that we are considering. We discuss these further at paragraphs 4.35-4.37.

2.29. We also note that the BSC P344 code modification will, if approved, facilitate better access for small DG to the Balancing Mechanism and so this would reduce the justification for differentials in the approach to BSUoS charging.

2.30. Baringa also highlighted the following areas as of medium materiality:

2.31. There are potential distortions to generation investment decisions as a result of inadequate forward-looking charges about transmission costs, most notably, in relation to the charging of costs associated with the Connect and Manage policy. Connect and Manage has brought benefits in terms of earlier connection but has also caused higher constraint management costs for the ESO. In the year leading up to September 2015 these costs were £121.7m[33]. These costs are paid by all who pay BSUoS (and ultimately by all consumers), not just the connecting party who has benefited. The result of Connect and Manage could be higher bills than necessary as full network costs are not being reflected in generators' investment decisions. However, the commissioning of the Western HVDC and Caithness Moray Links is likely to reduce constraints costs in the short-term. A further possible distortion is that the TNUoS locational model does not take into account where some areas of the network have more spare capacity than others. We consider that there may be scope to improve the forward-looking, locational signals sent through BSUoS and TNUoS arrangements but do not see it as sufficiently high priority to include in an immediate review.

2.32. The allocation of risk across transmission and distribution was also identified as an issue of medium materiality. Baringa identified two main issues -

- There is a risk that network operators invest in assets that are subsequently under-utilised. Investing in assets that are under-utilised pushes up costs for all consumers. There are risks of this on both the transmission and distributions networks. At transmission level, Baringa has highlighted concerns with the extent to which current user commitment arrangements protect wider users from the risk of users disconnecting early. In the National Grid 2018 Future Energy Scenarios (FES),[34] transmission connected generation ranges from 74GW to 88GW by 2025 – this represents a sizeable variation in utilisation of the transmission network. At distribution, Baringa highlighted concerns with socialising the cost of any reinforcement triggered by existing domestic

[33] Monitoring the 'Connect and Manage' electricity grid access regime, Sixth report from Ofgem, 14 December 2015. Calculated from the total annual constraint costs attributable to Connect and Manage between September 2014 and September 2015 divided by the total capacity of large generation connected under Connect and Manage
[34] National Grid's latest FES 2018 is available here: http://fes.nationalgrid.com/fes-document/

customer load growth. For example, DNOs may make significant investments now based on the current forecasts for when, where and how EV users are going to charge their EVs, but future innovation (eg induction charging or autonomous vehicles) could mean that these forecasts prove to be wrong and these assets could become stranded.

- Baringa also highlighted the open-ended, non-compensated curtailment risk that distributed generators with a 'flexible connection' face as a significant issue. Curtailment risk for DG on flexible generation has an estimated annual value currently of £12m[35].

How changes could impact users

2.33. We have developed case studies in order to help illustrate the impact of the problems with current arrangements and of the potential changes. A high level summary of these is show in figure 3, with further details in Appendix 4. We recognise that in developing and assessing options for change in more detail there will be a need to consider further case studies.

[35] 'Assessing the current issues with electricity network access and charging', Baringa Partners LLP, July 2018, available: https://www.ofgem.gov.uk/publications-and-updates/getting-more-out-our-electricity-networks-through-reforming-access-and-forward-looking-charging-arrangements

Figure 3: High level illustration of how changes could impact users

A generator connecting at distribution level

Currently, a new generation project may face a significant delay and/or upfront charge if it wants a standard connection in an area of the network that lacks spare network capacity. Alternatively, it can accept a connection that will involve its access to the wider network being interrupted at times, or it can relocate to another part of the network with spare capacity.

Once connected to the network, the generator will receive an annual credit from UoS charges, irrespective of whether the generator is providing a benefit or cost to the the network.

The changes we think should be considered could involve reducing upfront connection charges, while improving the accuracy of the annual UoS charges. We also think there could be improve to the options for access that better reflect users' needs, including giving those who agree that their access might be interrupted better ability to understand and manage that.

Similar changes could also apply to larger demand users.

A household that wants to charge an electric vehicle

Currently a household can install an EV charger (or other sources of demand, such as a heat pump) and not have to apply for an increased network connection, providing its needs can continue to be met given the size of the existing fuse in the household's meter. Their annual UoS charges will not accurately reflect the extent to which different choices in when (peak time or not) and how (fast vs trickle charging) they charge their EV will impact the need for the DNO to undertake expensive network reinforcement.

Our proposals will improve the accuracy of these charges for EV users and provide them with an opportunity to reduce their network charges if they are willing to be flexible about when, where and how they charge their EV. We do not envisage these changes applying to households' basic usage – we think this needs to be protected given it provides for essential needs.

3. Our proposals for the scope of review of access arrangements

Chapter Summary
Outlines our proposal for a review of access arrangements to explore options to improve the definition and choice of access rights, to clarify access rights and choices for small users and improve the allocation and reallocation of access rights.

➔ **Question 2:** Do you agree with our proposal that access rights should be reviewed, with the aim to improve their definition and choice? Please provide reasons for your response and, where possible, evidence to support your views.

➔ **Question 3:** Specifically, do you have views on whether options should be developed in the following areas as part of a review? Please give reasons for your response, and where possible, please provide evidence to support your views:

a) Establishing a clear access limit for small users, with greater choice of options (as considered under b) and c) below) above a core threshold – do you agree with our proposal in paragraphs 3.5-3.10 that this should be considered? Do you have views on how a core threshold could be set?
b) Firm/non-firm and time-profiled access – do you agree with our proposal outlined in paragraphs 3.15-3.21 that these options should be developed?
c) Duration and depth of access, discussed in paragraph 3.25-3.32 - would these options be feasible and beneficial?
d) At transmission or distribution in particular, or are both equally important – as discussed in this chapter?

➔ **Question 4:** Do you agree with the key links between access and charging we have identified in table 1? Why or why not? Do you think there are other key links we have not identified? Where possible, please provide evidence to support your views.

➔ **Question 5:** Do you agree with our proposal that targeted areas of allocation of access should be reviewed? Please give any specific views on the areas below, together with reasons for your response. Where possible, please provide evidence to support your views:

a) Improved queue management as the priority area for improving initial allocation of access, as outlined in paragraphs 3.41-3.44?
b) Not to consider the potential role of auctions for initial allocation of access as part of a review at this time, as discussed in paragraph 3.44?
c) To review the areas outlined in paragraphs 3.45-3.48 to support re-allocation of access?

Summary of scope of proposed review

3.1. When talking about “access rights”, we are referring to the network capacity that a user has allocated to them in order to import or export electricity. We have considered a range of options for reforming access arrangements, developing our view of these in discussion with industry and other stakeholders. We are proposing that a number of aspects of the arrangements should be reviewed.

3.2. The scope of our proposed review reflects the need to prioritise reform efforts and make timely progress. We have therefore focused on the changes we consider to have the greatest prospect of significant benefits to consumers. This judgement is informed by the evidence on the case for change in chapter 2.

3.3. In summary, we are proposing the review should focus on considering options to reform which can:

1. clarify access rights and improve choice for small users, including households
2. improve the definition and choice of access rights for larger users
3. improve the allocation of access rights, including establishing mechanisms to enhance the scope for markets in access.

3.4. We consider that reforms of this nature would offer good prospects of helping make better use of existing network capacity, supporting more effective competition between users and achieving a more efficient allocation of risk; leading to lower costs for consumers. Any reforms must also ensure that consumers, particularly those in vulnerable situations, have adequate network access that reflects the nature of electricity as an essential service.

Clarifying access rights and choices for small users

3.5. We are proposing to examine options to clarify access rights and choices for small users. Small users would incorporate domestic users, but also could include some small non-domestic users (eg micro-businesses[36]). This could involve requiring small users to specify the level of capacity they require, with a minimum standard 'core' level and enabling them to choose from a range of options (eg varying in firmness or time of access) if they want to go above this level. An alternative approach could involve placing a principles-based obligation on suppliers or another third party to determine the type of access that a small user needs for all their usage, requiring them to ensure they made that recommendation in line with a customer's best interests.

Reasons for our position

3.6. Demand at household level could increase significantly due to electric vehicles (EVs), heat pumps and other new technologies. This could lead to significant need for network reinforcement, with associated costs for consumers. We consider that there is a need to ensure access arrangements support efficient network development, so increased demand is enabled at efficient cost.

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[36] Here we are referring to employees with fewer than 10 employees and an annual turnover no greater than €2 million, or businesses that consume less than 100,000kWh of electricity or 293,000kWh of gas.

3.7. Many households will have relatively limited choice around their more essential needs. Some may be flexible when they consume electricity, but many users are not readily able to change when they consume. A core level of access could help ensure these basic needs are met and ensure consumers are protected from inappropriate access arrangements for these basic needs. There may be different options for how any core level of access could be set – eg considering users' volume of consumption or export, the capacity they use, or other relevant features of their usage patterns.

3.8. For higher usage levels, which may often represent more flexible, new loads, offering greater choice of access options, could enable those users who value continuous, higher level usage, to obtain that, while others who are able to be more flexible may choose options which reflect the benefits this flexibility provides, such as off peak or interruptible access. (The range of potential choices is discussed in further detail below).

3.9. A key challenge with this option relates to the variability in the nature of household demand and in how "essential" usage might be understood. Careful consideration would need to be given to how any limits or thresholds were set. We expect suppliers and/or third-party intermediaries may have an important role in ensuring access options are appropriate for a consumer's needs.

3.10. Each household will have their own needs and capabilities. We think better understanding of consumers' likely behavioural response would be helpful and we would encourage the industry to work with us to consider whether trials may have merit.

Improved definition and choice of access for larger users

3.11. For many users, the current arrangements are not explicit about the nature of access rights being granted to the system. This means that there is little, or a poorly defined, choice of different access options available to fit users' needs. The lack of definition also only provides limited information to network operators about where and when new network capacity is needed. We consider that improvements can be made to the definition and choice of access rights.

3.12. In reviewing access arrangements, we think there is merit in developing and assessing options to improve the definition and choice of:

- Firmness of access rights (ie when access might be curtailed and whether payment is available if it is)
- Time-profiled access rights (eg off-peak or seasonal access rather than year round)
- Short-term access rights (eg this could be a one year right)

3.13. We also invite views on the value and feasibility of developing options for:

- Defined long-term access rights (eg a fixed duration of multiple years)
- Local or shallow access rights (eg access to only trade over the local network)

Access options that we think should be developed further in the proposed review

3.14. We consider developing options for firmness, time-profile and short-term access rights should be developed in a review.

Reasons for our position

Firmness

3.15. Users' access to the network can vary in the nature and level of firmness. In practice, it will generally be unnecessarily expensive to have sufficient network redundancy to allow full physical firmness for all those connected to the system – in effect guaranteeing they would never experience constraints. There are differences, as described in Chapter 2, in the range of options available as the basis for access across the system.

3.16. We are proposing that the definition and choice of firmness of access rights that are available at distribution and transmission should be reviewed. In particular, we consider that this could lead to enhanced choice for users' access to the distribution network and potentially for small DG and demand users' access to the transmission network. For example, reformed access rights could include:

- Improvements to the definition of non-firm access at distribution (eg caps on the amount of time that a user with a flexible connection can be curtailed[37] without payment being available). We consider that this would make curtailment risk much easier for users to manage and make non-firm connection offers more attractive for some users.

- Improving clarity around the firmness of "standard" connections at distribution. This could potentially include introducing financially firm access rights at distribution, which would increase the consistency of arrangements at transmission and distribution, and would enhance access choice at distribution. While some improvements may be possible to better define firmness levels, we expect full reform in this area would require development of network standards to better define different

[37] By curtailment, here, we mean when a user's ability to import or export from the network is restricted.

levels of firmness at distribution. This would be a longer term development.

- Enhancing the scope for non-firm access at transmission. Our initial view is that this choice may have some merit, but it may be less likely to be attractive while the constraint management costs of connection ahead of wider reinforcement are socialised under Connect and Manage.[38]

- Improving clarity of access to the transmission network for small distributed generation (DG). This could include provisions for them to more explicitly agree a 'TEC' level, as larger generators do, and more clearly establishing the routes for them to benefit from the Connect and Manage regime, as larger generators routinely do.

3.17. Reviewing the definition and choice of non-firm access rights could reduce risk for network users by giving better information and choice to manage curtailment risk, allow more users to be connected, and provide better information to network operators about where there is demand for new network capacity. We expect commensurate changes to charges may likely be needed to support the above options – these are discussed further below. Improving the choice and definition of firmness of access rights was also identified as valuable by stakeholders in the Task Forces.

Time-profiled

3.18. Access rights could differ based on time. For example, a party could choose to have seasonal or "off-peak"[39] access to the network.

3.19. We are proposing that the definition and choice of time-profiled access rights at distribution and transmission should be reviewed. This could potentially lead to development of seasonal and off-peak access rights.

3.20. At the moment there is a long queue of customers wanting to connect to the system. Based on our discussions with the Task Forces, it is clear that users do not all necessarily want access at the same time. For example, many solar generators only want access during daytime hours. We consider that the use of time-profiled access rights could lead to better use of existing network capacity and should allow more users to connect quickly and without the need for expensive reinforcement.

[38] We expect network users would be less likely to see value in choosing less firm options for access if there were no associated saving for them. A similar situation may apply for other access options, such as 'time-profiled', discussed further below.
[39] If users agree to 'off-peak' access, ie to import or export outside peak times, when levels of demand or generation are at their highest, this can help avoid the need for reinforcement.

3.21. At transmission, again our initial view is that while the choice of time-profiled rights could have some merit, it may be less likely to be attractive to users whilst the costs of firm access ahead of wider network reinforcement are socialised.

Short term access rights

3.22. Short term access is already available at transmission. We consider that there are benefits from exploring the development of short-term access rights at distribution, which may be most suitable where there is spare capacity, and that this should be examined as part of the proposed review.[40]

3.23. Introducing short-term options could help allow greater utilisation of existing network capacity and provide additional choice to users. For example, closer to real time, additional short term capacity could be made available, as real time conditions 'on the day' allow. In the Task Forces, several network users expressed interest in obtaining short term access rights on top of their pre-existing access rights. This choice may also be of interest to generators nearing the end of their life that do not want to commit to long-term rights.

Potential wider options which the proposed review could explore

3.24. We are seeking views on the potential merits and feasibility of developing options for long-term access rights of defined duration, and depth of access, and whether this should be a focus of the proposed review.

Reasons for our position

Long-term access rights

3.25. Access rights could expire after a defined length of time or be 'evergreen' (with no fixed end date, though there could be other conditions). We are seeking views as part of this consultation on the potential benefits and feasibility of having long-term access rights of fixed lengths, and on whether this should be progressed as part of the proposed review.

3.26. There may be some benefits from defining fixed-term, long term access rights. Enabling users to choose a 15 year right, for example, could provide more clarity to system and network operators about long-term network demand and could help inform more efficient long-term network planning. We consider the benefits are likely to be limited unless the arrangements also include financial commitment from users for the duration of their access right. However, requiring

[40] In areas without spare capacity, new network investment is generally needed to provide access. Reinforcement can only be justified where there is demand for longer term access.

this level of user commitment, may make this option prohibitively expensive for some users, limiting its value.

3.27. Additionally we are aware that many network users may prefer open-ended access to the network. Fixed-term access rights may increase risk for some users. We consider that fixed term rights would have more value if users could be confident of being able to procure additional access rights, if and when required.

3.28. It may therefore be beneficial to prioritise the development of short-term access rights and markets for secondary trading, in advance of developing and considering options for fixed-term, long term access rights. We welcome views on this matter.

Depth/Local access

3.29. Access rights may be defined to apply to the whole system (ie allow access to the entire distribution and transmission system, and hence all GB markets). Alternatively, a party may have "local" access to a given geographical area or "shallow" access to a specific voltage level.

3.30. We are seeking views as part of this consultation on the potential benefits and feasibility of offering the choice for "shallow or "local" access, and on whether this should be progressed as part of the proposed review.

3.31. We consider that the development of local or shallow access rights could provide a useful signal about the benefits of matching generation and demand locally. This could enable additional access to local networks to be made available, where capacity further upstream is fully utilised. This could lead to more efficient use of the network and lower costs for consumers. It could also help reduce the size of the connection queue at distribution.

3.32. However, we consider that developing local access rights could be very complex. In GB we have a single electricity market with a uniform wholesale market price. Our current concern is that the development of 'local' access rights may have the effect of splitting GB's single market into multiple local markets (as participants are only acquiring access rights for a specific local network). This could introduce significant complexity, and could also have implications under EU law.[41] We consider that forward-looking charges alone could potentially provide an equivalent signal more simply, as discussed under our proposed comprehensive review of DUoS charges (see Chapter 4 below). Our provisional view is that a charging based approach is likely to be preferable.

[41] Specifically 'Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management' (https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32015R1222)

Key links between access choices and charging

3.33. Where there is a choice of different access options, it is important that charges reflect the relative difference in costs and benefits of these choices. We discuss charging further in the next chapter. Overall, our current view is that the stronger the emphasis on choice of access rights, the greater the case for capacity-based charges (ie charges that are based on the capacity requested by the users (eg kW) rather than usage charges (ie charges that are based on the volume of electricity consumed (eg kWh).

3.34. Table 1 below highlights at a high level what we currently consider to be the key links between access choices and charging for each policy area.

Table 1: Key links for each policy area

Policy Area	Key links
Firmness	Users with less firm rights should generally face lower charges. This currently occurs via reduced connection charges at distribution but could also be reflected via reduced UoS charges. We would need to give greater consideration to how this could be signalled via UoS charges if we moved to a shallower distribution connection charging boundary, because it could no longer be signalled via a reduction in connection charges
Time-profiled	Charges should reflect the costs of obtaining access at different times. Users with time-profiled access rights should generally face lower charges than those with 'round-the-clock' rights. The charges incurred should reflect the cost obtaining access at that specific time. This could be via UoS and/or connection charges. A greater take-up of choice around time-profile rights would support more of a capacity-based charging approach, with different charges for different profiled options (eg off peak access would have lower capacity charges), rather than time-of-use usage charges.
Duration	Currently UoS charges are based on estimating the long run marginal cost (LRMC) of providing access. This may not be appropriate for shorter-term rights, which may only be granted if

	there is spare capacity. In which case both short-term and long-term costs associated with providing that access would be low. For users who wished to choose long-term access rights, we think there is a need to consider how much financial commitment they make upfront to paying for this access over the years. This could take the form of an upfront charge, early exit charges, or requirements for securities against this liability.
Depth/local	Users with local or shallow access rights should face lower forward-looking charges than those with access to the whole system, if they contribute to lower network costs. The charges incurred should still reflect the costs that they create on the network. For example, a party may only require local access for the majority of the time, but may still be reliant on the wider network during certain periods (eg when their own generator is offline). If this is the case then parties should incur costs that reflect this.

Improving the allocation of access rights

3.35. We have considered what improvements could be made to the allocation of access rights, including whether more market-based approaches could be used to allocate access (both at its initial allocation and any subsequent reallocation).

3.36. An alternative to the first-come-first-served approach we currently have, described in chapter 2, would be for initial allocation of access rights to be through an auction, run by the ESO, DNOs or other parties.

Initial allocation

3.37. We are proposing that incremental improvements to queue management activities should be investigated as part of a review of access arrangements.

3.38. We are not proposing that this review includes:

- 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
- Changes to Connect and Manage to:
  - extend the policy to allow for connection of DG ahead of wider reinforcement of the distribution network or
  - to change the existing allocation approach at transmission (other than to clarify its application for DG, as discussed in paragraph 3.16.).

3.39. For both targeted auctions for the initial allocation of rights and the potential to introduce 'Connect and Manage' arrangements for distribution capacity, we think they may merit consideration at a later date but we do not see them as an immediate priority.

3.40. We are also not proposing that the review considers the option for universal auctions for the initial allocation of access rights (ie auctions that apply to all parties).

Reasons for our position

3.41. We consider that better queue management activities can help speed up the connection of developments that are genuinely ready to progress. This should make better use of the existing network capacity and help reduce the time users need to wait to connect.

3.42. We consider that the use of 'targeted' auctions for the initial allocation under certain situations (eg where significant queues exist), could have benefits for consumers. For example, this could help ensure those that value access most are able to obtain it and provide better signals to network operators about the need for new network capacity. However, 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. The development of targeted auction is also relatively complex and we believe that there is a strong synergy in considering the potential scope for this across both transmission and distribution together. We therefore propose not to prioritise the development of targeted auctions for initial allocation at this stage.

3.43. We consider there are benefits to the existing allocation approach under Connect and Manage, whereby generators are able to connect to the network without waiting for wider reinforcement which may be needed. There may be benefits to extending this regime to distribution. However, to fully implement this would require the establishment of firm access rights at distribution and this is unlikely to be achievable in the short term, due to the need to develop new network planning standards. Flexible connection options, as an example of non-firm access, offer an alternative approach. We are therefore not proposing to consider changing this allocation approach at transmission, or extending Connect and Manage to distribution as an immediate priority area. We note that any future proposals to consider extending Connect and Manage to distribution should include considering more cost-reflective charging for constraint management costs than the approach currently adopted at transmission (where the costs are socialised).

3.44. We are not proposing that this review should consider universal auctions for the initial allocation of access rights. Conceptually, these could enable a market to drive the efficient allocation of access and the auction / traded price would provide an accurate signal for the value of additional network capacity. However, in practice, auctions have many challenges which mean we do not think they offer sufficient promise of benefit to warrant the level of disruption involved. For example, auctions would be complex to administer, it would be difficult to achieve liquid trading and we are concerned that the complexity of participating in an auction could create a barrier to new entrants. We think a number of these challenges could be greater at low voltages, yet this is a key area where there is a case for change. In particular, members of our Task Forces raised significant concerns about the development of universal auctions, questioning their practicality and citing the uncertainty such a regime would create.

Reallocation of access rights

3.45. We think a review of access arrangements should include developing and assessing options to:

- Establish new access conditions (eg 'use it or lose it' or 'use it or sell it')[42]
- 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.

Reasons for our position

3.46. We consider that developing new conditions of access (eg 'use it or lose it' or 'use it or sell it') has the potential to allow additional users to access the network, by increasing the utilisation of the existing capacity (eg by reducing capacity hoarding[43]). Options of this nature could help reduce costs for all consumers.

3.47. We consider that developing mechanisms to enable distribution-connected users with non-firm access to trade with others to reduce their curtailment will allow more efficient allocation of access.[44] For example, a user that is due to be constrained could pay another party to be constrained instead (or turn up[45], for example if demand turn-up can help offset a constraint caused by generation exports). This could help ensure access is available to those that can provide most

[42] Access rights can be constructed as a pure option to use the network up to a given capacity limit, or with more specific conditions associated with them which may support more efficient use of available capacity. For example, 'use it or lose it' or 'use it or sell it' access condition could require users to release unused capacity back to the relevant ESO/DNO or to other network users.
[43] By capacity hoarding, here, we mean where network users with capacity allocated to them hold on to it, even though they do not need to use it, even where other users may be queuing for access.
[44] 'Actively Managed Distributed Generation and the BSC', ELEXON, June 2014
[45] Demand turn-up is a type of flexibility where a demand user increases their demand on the network. This can have a broadly equivalent effect from the network perspective as a generation user reducing their export.

value to the system and improve the investment case for projects with non-firm access by increasing their ability to manage curtailment risk. In collaboration with Baringa, some of the DNOs have already made progress to start developing this mechanism.[46]

3.48. We consider that better enabling the exchange of access rights between users will allow the network to be utilised most effectively by those parties that value it the most. We think there is the clearest case for considering this at distribution level as the CUSC already provides for the exchange of access rights (TEC exchange).[47]

[46] 'Actively Managed Distributed Generation and the BSC', ELEXON, June 2014
[47] Under the CUSC, TEC holders can apply to the ESO to 'exchange' their TEC with another party under certain conditions.

4. Our proposals for the scope of review of forward-looking network charging

Chapter Summary
Outlines our proposals for a comprehensive review of forward-looking distribution use of system charging, a review of the distribution connection charging boundary and a focused review of forward-looking transmission use of system charging.

➔ **Question 6:** Do you agree that a comprehensive review of forward-looking DUoS charging methodologies, as outlined in paragraphs 4.3-4.7, should be undertaken? Please provide reasons for your response and, where possible, evidence to support your position.

➔ **Question 7:** Do you agree that the distribution connection charging boundary should be reviewed, but not the transmission connection boundary? Please provide reasons for your response and, where possible, evidence to support your position.

➔ **Question 8:** Do you agree that the basis of forward-looking TNUoS charging should be reviewed in targeted areas? If you have views on whether we should review the following specific areas please also provide these:

a) Do you agree that forward-looking TNUoS charges for small distributed generation (DG) should be reviewed, as outlined in paragraphs 4.19-4.23?

b) Do you consider that forward-looking TNUoS charges for demand should be reviewed, as outlined in paragraphs 4.24-4.27?

Please provide reasons for your response and, where possible, evidence to support your position.

➔ **Question 9:** Do you agree that a broader review of forward-looking TNUoS charges, or the socialisation of Connect and Manage costs through BSUoS at this time, should not be prioritised for review? Please provide reasons for your response and, where possible, evidence to support your position.

➔ **Question 10:** Do you agree that there would be value in further work in assessing options to make BSUoS more cost-reflective, and if so, that an ESO-led industry taskforce would be the best way to take this forward?

Summary of scope of proposed review

4.1. As with the proposed scope of the review of access arrangements, our proposal for areas to be reviewed for forward-looking charging signals reflects evidence on the case for change and the need to prioritise areas to allow timely progress. In summary, we are proposing:

1) A comprehensive review of forward-looking DUoS charges;
2) A review the distribution connection charging boundary; and
3) A more focused review of forward-looking TNUoS charges.

4.2. We consider that these reforms should improve signals to users to make better use of existing network capacity, support more effective competition between users and achieve a more efficient allocation of risk. This should lead to lower costs for consumers.

DUoS charging

4.3. We are proposing a comprehensive review of both forward-looking DUoS charging methodologies (the CDCM and EDCM) to ensure that they are fit for purpose. Areas of focus will include:

- **Considering introducing greater granularity to CDCM charging (for LV and HV distribution networks), so that charges are more reflective of actual local network conditions.** For example, changes could mean that DG in generation-dominated areas could pay a charge rather than receive a credit, while demand could receive a credit. While it may ultimately be possible to do, we recognise that building comprehensive network models to allow load flow modelling (as with TNUoS and EDCM) may be difficult to achieve in the near term at the lower voltages given inadequate information currently about the high volume of distribution assets at that level. We think at this time, alternative approaches will need to be considered to provide more locational signals, for example, classifying the distribution system into different "zones" (eg 'generation dominated", "demand dominated"). As part of our review we will consider whether there should be limits on the extent to which small users (eg domestic) usage should be subject to cost-reflective locational signals.

- **Considering changes to how the locational signals are produced in the EDCM charging (for EHV) to improve predictability.** Options could include moving to a zonal approach, as described above, or aligning with the approach used for TNUoS forward-looking charging signals.

- **Considering the balance between usage-based charges (including time-of-use charges) and capacity-based charges provide to provide better cost-reflective forward-looking charges.** For small users that are Half-Hourly (HH) metered, this may mean increasing the focus on capacity-based charges. The ultimate approach will also need to be robust to the development of newer models and technologies, such as the provision of vehicle-to-grid services from EVs, which may mean typical demand users also 'export' electricity onto the networks. We will also need to consider the arrangements that apply to non-HH metered customers and how these align with the arrangements that HH metered customers.

Reasons for our position

4.4. Greater locational and temporal granularity at the lower voltages could give better signals to users about where and when using the network would create costs or benefits, decreasing the need for future investment in the network. As identified in chapter 2, we consider that, without the right signals, the electrification of heat and transport could lead to significant additional costs for consumers. Improved forward-looking charges could also reduce distortions from DG receiving credits even where contributing to network constraints, and encourage DG projects that locate in areas where they can provide network benefits and so help reduce consumer bills.

4.5. Improving predictability of EHV charges could reduce risks to users connected at EHV and help them react to signals.

4.6. Considering the balance between time-of-use based usage charges and capacity-based charges could also help improve cost reflectivity of DUoS forward-looking charges. We consider that rebalancing towards capacity-based charges could better reflect the costs or benefits created by users' specific access choices. For example, if a user chooses to have time-profiled 'off-peak' access to the network, then increasing the focus on capacity-based charges should better reflect the reduction in reinforcement costs, than a volumetric, ToU charge. This could help reduce the need for reinforcement and ensure those users driving the need for new network investment would pay a larger proportion of these costs. We consider that these changes would complement our proposals to improve the choice and definition of access rights. As part of our review, we will need to consider how these reforms would impact a range of different users (including both HH and non-HH users).

4.7. We consider that there are likely to be limits to the extent to which cost-reflective charges are appropriate for the basic energy requirements of small users. The benefits of locational signals are reduced where there is less prospect of users responding to the signal and moving demand or generation to a different location, which is the case for much of an existing household's basic usage[48]. However, they can still have value where households are able to flex when they use electricity, as that flexibility will be more valuable in areas where the network costs it can help avoid are higher. This needs to be set against the consumer acceptability of greater locational variability of network charges, and the risk that they could adversely impact those in vulnerable situations. We do not think it would be appropriate for use of system charges to mean households' basic, often less flexible needs would differ on a highly granular locational basis. We think this will need to be explored further as part of a comprehensive review of distribution charging and alongside work on defining access rights for small users.

[48] Electric vehicles will be a key exception to this, with scope for home or public/workplace charging and uncertainty about which model will dominate.

Connection charging boundary

4.8. We propose a review of whether it would be in consumers' interests to move to a shallow connection[49] charge at distribution.

4.9. We think the review of the distribution connection charging boundary should also consider whether changes are required to the user commitment arrangements or timing of payment at distribution. This would include considering whether arrangements should differentiate by classes of user or voltage level.

4.10. We are not proposing to review the connection charging boundary at transmission. We note that within TNUoS generators pay a local circuit charge for infrastructure between the location of generation and their first connection to the Main Integrated Transmission System (MITS). We think there may be a need to consider whether the definition of these assets works in all cases, particularly where major network extension works are needed to allow the connection of new generation. We invite industry to consider whether changes may be necessary to better meet the CUSC objectives in this area.[50]

Reasons for our position

4.11. The existing shallow-ish connection boundary sends a locational signal to new network users about the most efficient location to connect on the network, however the potential high upfront cost of connection may also create a barrier to connect to the network. Moving to a shallower connection charging boundary at distribution could reduce barriers to entry for those wanting to connect to the distribution network, as it would mean that new connections would no longer principally bear the costs of any reinforcement.

4.12. This advantage is likely to be contingent on being able to send better locational signals through ongoing DUoS charges, if these were removed from the upfront connection charge. It is therefore highly linked with the comprehensive review of DUoS charges.

4.13. If we introduced more locationally varying UoS 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

[49] A shallow connection boundary would mean that new connectees only pay for their own their own sole-use assets through the connection charge, and not also any wider reinforcement and shared operational costs that are triggered

[50] For the avoidance of doubt, this does not concern the interpretation of the European Commission Regulation 838/2010, or Ofgem's decision to reject CMP261. Please see our recent open letter for our latest views on this issue: https://www.ofgem.gov.uk/publications-and-updates/ofgem-s-views-following-decision-reject-cmp261

capacity from a wider group of network users. In contrast, under a shallow-ish connection charge, the cost of reinforcing the network is focused in the first instance on the potential 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. However, a shallow-ish connection boundary means users who contribute to causing reinforcement make their contribution to those costs up front.

4.14. If we were to make the distribution connection boundary shallower, and send locational signals through DUoS, consumers rather than the connecting party would bear the risk of funding those assets over their lifetime. We therefore think it is important that potential new user commitment arrangements, similar to those at transmission, are assessed alongside options to change the distribution connection boundary. These could help reduce risk of stranded assets, though they could also be burdensome to administer and add complexity for small users. We therefore believe the review would need to consider the appropriate allocation of risk and whether this might vary for different types of user.

4.15. We are not proposing to include the transmission connection charging boundary in the scope of the proposed review as we have not seen evidence which suggests that the current boundary could be causing significant consumer detriment. We acknowledge that improvements may be merited to the definition of local circuits within the TNUoS charging methodology. We see this as a discrete area of work and think this is best considered by industry through the open governance arrangements in the CUSC. There would also be opportunity for work through industry forums such as the Charging Futures Forum.

TNUoS and BSUoS charges

4.16. We are proposing that the scope of review of TNUoS forward-looking charging arrangements should focus on the basis of TNUoS charging of small DG, and whether this should be aligned with the charging of larger generators, rather than generally being treated as 'negative demand'.[51] This would ensure that generators across voltage levels receive consistent forward-looking signals, and mean that TNUoS charges for small DG would no longer be capped at zero and could be charged based on a generator's agreed capacity (akin to TEC) rather than generation during triad periods.

4.17. We are seeking views on whether the review should also include the basis of TNuoS forward-looking charging of demand. Options could include moving away

[51] Larger generators that are connected to the distribution network, have a generation licence and a Bilateral Embedded Generator Agreement (which gives the generator the right to export onto the transmission network and to operate in the energy balancing market) are liable for TNUoS charges.

from using triad periods towards fixed time of use periods, or charging based on an agreed capacity.

4.18. At this stage, we not proposing that the review includes:

- the Transport Model methodology for setting locational tariffs
- the current socialisation of Connect and Manage costs through BSUoS.

Areas we are proposing should be reviewed

4.19. We are proposing that the basis of TNUoS forward-looking charging for small DG should be reviewed.

Reasons for our position

4.20. Although they are connected at distribution-level, DGs can still impact flows across the transmission network. In some areas, the amount of DG connected to the system means that there are exports of electricity from distribution networks onto the transmission network. This can contribute towards transmission network constraints and so increase whole system costs. They can also reduce transmission network constraints when they locate in areas where demand exceeds generation.

4.21. There are two key differences in how small DG are treated for TNUoS charges. First, they are treated as negative demand and hence receive payments/credits on the basis of demand during the 'triad periods', whereas larger generators are charged based on their Transmission Entry Capacity. Second, to prevent incentives on small DG to reduce output during peak periods, a 'floor at zero' has been introduced which means they don't pay TNUoS charges when they are adding to transmission network flows (and hence costs).

4.22. Aligning small DGs' charging with that of larger generators would ensure that all generators would receive the same transmission forward-looking charges, meaning that they would receive TNUoS credits in zones where they are expected to reduce long term transmission costs, and pay TNUoS charges in zones where they are expected to increase long term costs. This could reduce transmission network costs by improving signals for all generators to locate where they can reduce network costs. This can also reduce distortions to competition between generators connecting at different network locations and support more efficient whole system outcomes.

4.23. We also think there would be a need to consider moving to a capacity-based charge for DG if the cap on DG TNUoS charges at zero were removed, otherwise we consider there would be a significant incentive for DG to avoid generation during triad periods. This could distort operational decisions and lead to higher overall costs for consumers. We think such an option could need consideration of how the ESO would charge small DG given that there is typically no existing contractual relationship – options could involve suppliers or DNOs acting as the agent on the ESO's behalf.

Potential further areas which could be included in a review

4.24. We are seeking views on whether the proposed review should also include the basis of the forward-looking TNuoS charging of demand. This could result in charging demand based on their capacity requirement rather than usage, or moving away from charging based on demand during triad periods to fixed time of use windows (similar to the approach to time of use charging under DUoS).

Reasons for our position

4.25. The current approach to charging demand customers based on their usage during triad periods may be introducing uncertainty, as the timing of triad periods is becoming increasingly difficult to predict. Also, they may not always align with periods of peak network constraints in particular areas. Against this, where they do align, we consider the demand reduction engendered by the triad approach has value. This is particularly true when the customers responding to triad are not participating in the Balancing Mechanism (either directly or via aggregators), and so would not otherwise provide demand response to support system needs.

4.26. For demand customers with onsite generation, that generation is charged as negative demand based on generation during triad periods, whereas larger generators incur a capacity-based charge. This could be introducing distortions to both investment and operational decisions between onsite generation and other generation, potentially leading to higher system costs and higher consumer bills than necessary.

4.27. We are seeking stakeholders views on whether this area should be reviewed within the scope of this proposed review.

Areas we are not proposing should be reviewed at this time

4.28. We are not proposing a wider review of forward-looking TNUoS charges or of the socialisation of constraint management costs within BSUoS as part of the priority areas of this proposed review.

4.29. However, we do think there would be value in further work on BSUoS more generally to consider whether it can provide better forward-looking signals for the different costs elements it recovers. We are continuing to consider how best this question should be taken forward. One option would be for this to be taken forward by a taskforce under the Charging Futures Forum, which could be led by the ESO. We would welcome views on this area.

Reasons for our position

4.30. The methodology for setting forward-looking TNUoS charges was reviewed relatively recently through Project Transmit and Baringa's work and our own analysis we have not identified evidence to demonstrate a strong need to review wider elements of TNUoS (including the locational model), beyond the issues above.

4.31. There are possible options to change the underlying model that produces wider locational TNUoS tariffs so that areas with less spare capacity get sharper signals, or to review whether the network planning scenarios used to adequately reflect new cost drivers (such as exporting GSPs during low demand periods in summer). We consider that there may be merit in reviewing these at some point, but do not consider it is a priority given that implementing these changes would be relatively complex and the current evidence of potential consumer detriment is less clear. We therefore are not proposing a wider review of TNUoS charges at this time, but think this could potentially be revisited once the direction of travel on any reforms to forward-looking DUoS charges is clearer.

4.32. Some stakeholders have also previously argued for a change to the "reference node" in the TNUoS charging model. The model currently calculates the incremental cost of flowing electricity at different areas on the network relative to a distributed demand reference node.[52] Changing the reference node would change the revenue recovered from forward-looking charges recovered and the proportions recovered from generation and demand. Our current view is that we are not convinced there are compelling arguments for this, but we would welcome any evidence on this matter.

4.33. We consider that there would be benefits from considering whether some elements of BSUoS could be made more cost-reflective and hence provide stronger forward-looking signals. In the context of this project, we have considered how BSUOS currently socialises the constraint management costs resulting from the Connect and Manage regime. We think there could be value in recovering these costs in a more cost-reflective manner, for example through a locational element to BSUoS charges. Alternatively, the costs could be signalled through introducing a premium to TNUoS for those users that are benefitting from Connect and Manage (potentially limited to the period before relevant wider network reinforcement is complete). We note that the government would need to approve any change to the socialisation of constraint management costs and we would therefore engage with them as part of any review.

[52] A distributed demand reference node means that a proportional of the additional demand to match the incremental 1MW of generation, is added to each demand node relative to the node's original demand. This methodology was introduced by CMP213 (Project Transmit). The previous methodology used a single reference node – at the demand centre of the system – where the entire 1MW of corresponding additional demand was added.

4.34. We do not see changes in this area as an immediate priority as the commissioning of the Western Link and Caithness Moray should reduce these constraint management costs in the near-term. We do consider there is likely to be merit in reviewing this at a later stage as we consider it is likely that constraint costs could begin to rise again in future.

4.35. We note also that there are wider questions about BSUoS, such as have been raised through the CUSC modification proposal CMP250 and through our work on embedded benefits and the TCR. While we do not propose to progress work on BSUoS as a priority within the scope of our access and forward-looking charging work, we consider that there would be value in further work on BSUoS more generally.

4.36. We are keeping the BSUoS embedded benefit under review as part of the TCR. We have also indicated that if BSUoS (or elements of it) remains a cost recovery charge, then we will consider whether to reform it in line with any reforms to the TNUoS and DNUoS residual charges we make as part of the TCR.

4.37. To support this latter element and help establish the long-term direction for BSUoS, and notwithstanding potential reform to the embedded benefit, we think there is a need for further analysis of whether the different cost elements it recovers could be charged for more cost-reflectively. We think a taskforce under the Charging Futures Forum would be one way to take this question forward. This could be led by the ESO given its role in ensuring the transmission charging arrangements are fit for purpose, with input from wider industry.

5. Taking forward this review

Chapter summary
Outlines our proposals for how our suggested priority areas for review should be taken forward, including the relative role of Ofgem through a proposed Significant Code Review (SCR) and the industry.

- ➔ **Question 11:** What are your views on whether Ofgem or the industry should lead the review of different areas? Please specify which of SCR scope options A-C you favour, or describe your alternative proposal if applicable. Please give reasons for your view.
- ➔ **Question 12**: Do you agree with our proposal to launch an 'Option 1' SCR for areas of review that we lead on? Please give reasons for your view.
- ➔ **Question 13:** Do you agree with the introduction of a licence condition on the basis described in paragraphs 5.11 and 5.12 and Appendix 5? Why or why not? Do you have any comments on the key elements set out in table 7 of Appendix 5a, or consider there are any other key elements which should be included? Please give reasons for your view.
- ➔ **Question 14:** Do you have any comments on the draft wording of the outline licence condition included at Appendix 5b? Please give reasons for your view.
- ➔ **Question 15:** What are your views on our indicative timelines? Do you foresee any potential challenges to, or implications of, the proposed timelines and how could these be mitigated?
- ➔ **Question 16:** What are your views on our proposals for coordinating and engaging stakeholders in this work?

Summary of our proposed approach to the review

5.1. We have considered a range of options for how a review of these aspects of access and forward-looking charging arrangements should be taken forward. In summary, we are inviting views on:

1. Leadership of the review(s)
   a) Our proposal to launch a Significant Code Review (SCR). At a minimum, we think the SCR should cover the proposed review of small users' access rights and forward-looking network charging changes
   b) Whether the ESO and DNOs (with the involvement of other stakeholders) should lead the proposed review of larger users' access rights and improvements to allocation arrangements, with expectations set out in new licence obligations, or whether these should also be in the scope of our SCR
2. The type of SCR we launch.
3. Our expected timelines for review and implementation of any changes
4. Our proposals to ensure coordination and effective input from the industry and stakeholder engagement

Leadership of the review

5.2. Broadly, any review and resulting reform of arrangements can be taken forward through either an Ofgem-led or industry-led approach. We can launch a SCR where we think Ofgem leadership is necessary to address an existing or anticipated defect in the industry arrangements where the solution can be given effect, through code modifications and other consequential changes, and the area of work is likely to create significant cross-code or code-licence issues.

5.3. The process provides a tool for Ofgem to initiate wide ranging reforms and facilitate delivery of complex and significant changes to the industry codes. Once a SCR has been launched, new modification proposals, which cover similar ground to the SCR, may not proceed through the standard industry modification process. Only urgent proposals or those specifically exempted by us will be allowed to proceed through the code modification process.

5.4. The industry can also lead reforms. A wide range of parties[53] can propose modifications to industry codes, though in practice, we see the prime candidates for leading wide-ranging reforms to the network access and charging arrangements as being the ESO and network operators. They hold key expertise on how the networks are planned and operated, and how this is reflected in access and charging arrangements. They are also well placed to understand the needs of their customers through their engagement and are able to drive forward changes to their processes for allocating network access where these are not determined by codes.

5.5. We are proposing to launch an SCR to take forward review of some areas, and that the industry should lead a review of other areas outside of this process. An industry-led review could enable continued momentum of progress in certain areas, and help ensure strong industry input, in line with their responsibility to ensure resulting arrangements remain up to date. These changes could be taken forward, often reasonably quickly, by industry under the standard code modification process. However, we are aware that such an approach could risk fragmented thinking between areas that fall within the SCR scope and those that are taken forward by the industry, where an SCR could offer benefits in ensuring a coordinated review where areas are related.

5.6. Should an industry led review take place on areas outside the scope of an SCR, we consider that the ESO and network operators would be best placed to lead this. We anticipate this would involve developing analysis and raising code

[53] A party to an industry code is any company that has acceded to that industry code. This often includes licensed electricity companies who are required by their license obligations to be parties to specific industry codes. Code parties, and other bodies as set out in the relevant industry code, are able to raise mods to that code.

modifications to relevant industry codes. We would also expect code bodies[54] and wider stakeholders to have a role in this review. We welcome views on this thinking.

5.7. Table 2 below shows the proposed options for the scope of the SCR and the areas where Ofgem or the industry could be leading:

Table 2: Options for scope of an SCR

Options for SCR scope	**Proposed areas to be covered in SCR**	**Proposed areas for industry led review outside an SCR**
A. Narrower	a) A comprehensive review of forward-looking DUoS charging arrangements b) Review of distribution connection charging boundary c) Focused review of forward-looking TNUoS charging arrangements d) Reviewing options to improve definition and choice of access rights for small users, including households	e) Reviewing definition and choice of access rights for larger users f) Reviewing allocation of access rights.
B. Moderate	Areas a) – d) above and: e) Reviewing definition and choice of access rights for larger users	f) Reviewing allocation of access rights.
C. Comprehensive	Areas a) - e) above and: f) Reviewing allocation of access rights.	No areas

Our initial view and proposed approach

<u>Scope of an SCR</u>

5.8. Our current view is that either a narrow or moderate scope for the SCR (Options A and B outlined in table 2 above) would be the best approach. Our current view is that, at a minimum:

- the areas identified under the narrow SCR scope (areas a)-d)) should be progressed under an SCR; and

[54] When we refer to code bodies, we are referring to code administrators, code parties and code panels, as appropriate.

- the industry is best placed and should lead on improving allocation of access (area f).

5.9. We are seeking views on the scope of the proposed SCR, including whether the review of access rights for larger users should also be included within an SCR, or a review led by industry. We would also welcome views on or whether there are other variants or hybrid options that could have value.

Role of industry

5.10. We propose that the ESO and DNOs should lead areas that fall outside of the scope of the SCR under the narrow and moderate options. These could include developing and assessing options for better definition and choice of access rights for larger users and improving the allocation and reallocation of access. We would expect code bodies and other stakeholders to also have a strong role.

5.11. It will be important to ensure the industry makes timely and effective progress in any areas where it leads outside an SCR, to deliver the most benefit for consumers. To ensure this, we consider there may be value in introducing new licence obligations on the ESO and DNOs to undertake a review and bring forward modification proposals that they consider have merit in the areas identified.

5.12. The key elements we would propose to include in a licence condition are set out in Appendix 5a. This includes who the conditions could apply to, deliverables, key aspects of approach and timescales. We set out an illustrative outline draft of the proposed licence condition in Appendix 5b.[55] We are inviting views on the value of introducing such obligations and the illustrative draft wording of the proposed licence condition. This is not a statutory consultation pursuant to s11A of the EA89, which we would undertake in due course, if we were to decide to introduce conditions as proposed here.

5.13. We also expect that industry and other stakeholders would have a strong role in supporting the development and analysis of options that fall within the scope of an SCR. Again, we expect that the ESO and network operators would have a key role but consider that code bodies and wider stakeholders would also need to be involved, and outline proposals to ensure effective input below.

Reasons for our initial view

5.14. We think an Ofgem-led approach, under an SCR, is appropriate for those areas where there are significant cross-code issues, interactions with price control arrangements, or change may be more contentious and could risk stalling progress, or for example where there could be significant distributional issues. In

[55] As set out in Appendix 5, this proposed licence condition would not apply if we decide to pursue a comprehensive scope SCR (option C, table 2)

contrast, we think an approach led by the ESO and DNOs, building on their responsibility to keep arrangements updated, would allow them to leverage their expertise and potentially allow quicker wins ahead of the conclusions of an SCR process.

5.15. Given this, we consider that, at a minimum, an SCR should include:

- The review of access options to improve definition and choice for small users, including households, given these could lead to fundamental changes that will need consideration of sensitive questions particular for vulnerable and less engaged consumers. There are also close links with wider Ofgem policy developments, which will need to be considered.

- The reviews of forward-looking DUoS and TNUoS charging arrangements, given the need to consider alignment in approaches across them, and that changes could involve significant distributional impacts between parties

- The review of the distribution connection charging boundary, given the extent of the potential change and links with RIIO-ED2 price control arrangements.

5.16. Industry has actively pursued improvements to access arrangements in recent years, building on direction by Ofgem through our work on the joint plan with the government for a Smart, Flexible Energy System, and “Quicker, More Efficient Connections”. The introduction of flexible (non-firm) connection arrangements and notable programmes such as the ENA’s Open Networks have shown industry can collaborate effectively to undertake coordinated work in response to the energy system transformation. With clearly defined outputs, we believe industry could successfully lead review and reform to enable improved allocation and reallocation of access. It is important industry continues to make progress in the near term to better meet the needs of its customers.

5.17. We think an industry-led approach in this area should build on existing momentum, is in line with industry’s responsibility for ensuring the resulting arrangements remain up to date as the system evolves in the longer term, and supports the delivery of improvements ahead of any code modifications that might be raised at the end of an SCR phase being implemented. Though we recognise there are interactions, we think the work could be taken forward separately and alongside the SCR-led work, providing updates and input to any SCR thinking as needed. For example, under Option A, the work to review access rights for small users (within the SCR) would need to be closely coordinated with the review of access rights of larger users (outside of the SCR).

5.18. We are also inviting views on whether the review of access rights for larger users should also be included within an SCR (under the moderate scope, B) or led by industry (our proposed narrow scope of SCR, A). We consider this is finely balanced and both approaches have pros and cons:

- **Narrower scope (option A, table 2):** We see potential merits in industry leading work outside of the SCR on better definition and choice of access rights for larger users, together with improved allocation of access, given these areas are related. This could draw on industry's expertise and create opportunities for changes to be implemented sooner than under an SCR process. We welcome views on the opportunities industry sees to achieve this.

- **Moderate scope (option B, table 2):** The moderate scope could help ensure coordination of the links between access right definition and choice for both small and large users. However, this would separate access rights options development for larger users from allocation arrangements, and may hinder quicker wins. We welcome views on these issues.

5.19. In general, we expect industry to continue to work in parallel to ensure connection arrangements and constraint management are efficient and meeting customers' needs in the near term. We welcome the progress being made through initiatives such as Open Networks, and expect to see industry deliver continued rapid progress, as we signalled in our joint plan with the government for a Smart, Flexible Energy System.[56] Following this work, we may provide further clarity on our expectations for short-term progress.

5.20. We encourage stakeholders to continue to feed in their views on priority areas for near term progress through mechanisms such as the Incentive on Connection Engagement (ICE).[57] Where we are leading work under a SCR, we would engage with industry to agree which areas should be taken forward where there may be code implications which interacted with the SCR scope.

5.21. We believe that the introduction of new licence obligations on network and system operators would ensure that modification proposals in areas outside a SCR will be developed in a timely and effective manner.

5.22. We would expect industry to support options development and analysis of key areas within the scope of SCR, given their technical expertise and the integral nature these arrangements play in the operation of their networks, in addition to leading on any areas outside the SCR.

[56] https://www.ofgem.gov.uk/system/files/docs/2017/07/upgrading_our_energy_system_-_smart_systems_and_flexibility_plan.pdf
[57] The ICE incentivises DNOs to engage effectively with their larger connections customers. We recently published a consultation on the DNOs' ICE plans, available here: https://www.ofgem.gov.uk/publications-and-updates/incentive-connections-engagement-consultation-distribution-network-operators-2018-submissions

Options for the SCR process

5.23. Changes following our Code Governance Review (Phase 3) established three options for the SCR process – each with varying levels of Ofgem involvement following publication of our conclusions. [58] These are:

- **Option 1: Ofgem directs licensee(s) to raise modification proposal(s).** At the end of the SCR phase we would issue a direction to the relevant licensee(s). Our direction may set out high level principles (with the detail to be developed by industry) or more specific, detailed conclusions to be given effect through code changes. The modification(s) would follow the standard industry code modification processes.
- **Option 2: Ofgem raises modification proposal(s).** At the end of the SCR phase we would raise the modification(s) under the relevant code(s), which would then be taken forward through the standard industry code modification processes.
- **Option 3: Ofgem leads an end-to-end process to develop code modification(s).** The standard industry process for modification proposals would not apply; Ofgem would lead consultation and engagement needed to develop the appropriate code change(s). We would expect close industry involvement. We may establish and lead workgroups similar to the approach under the standard industry code modification processes (but led by us).

Our initial view and proposed approach

5.24. We consider Option 1 is likely to offer the best prospect of benefits and are proposing to launch a SCR of this type. This would mean, at the end of the SCR phase, if we consider code changes are necessary, we would expect to issue a direction to the relevant licensee(s) to raise modification proposals to address those code matters, as set out in our SCR conclusions.

5.25. We note that there is scope to review the approach during the SCR if it appears that another SCR type would better deliver benefits for consumers and will keep this under review.

Reasons for our initial view

5.26. We believe that an Option 1 SCR offers the right balance between Ofgem leadership on these holistic and strategic changes and industry expertise in developing and drafting modifications. We think our proposed approach has particular advantages when combined with strong engagement from industry.

[58] The SCR process was introduced in 2010 and later revised following Ofgem's Code Governance Review (Phase 3) (CGR3) in 2016. Our full SCR Guidance is available here: https://www.ofgem.gov.uk/system/files/docs/2016/06/scr_guidance.pdf

5.27. We believe that providing a well-defined scope, consistent governance and effective coordination to provide overall direction, can achieve the desired outcomes in a timely way, while building on industry's expertise in the later stages.

5.28. However, given the broad range of the proposed review, which may span multiple codes, we recognise a wider role for Ofgem could have advantages in supporting coordination. We are aware that the ultimate scope of review may have implications for other aspects of the review approach, such as the type of SCR or structure of the review programme, with potential for other variants or hybrid options. We will consider our approach in light of responses received.

Timelines

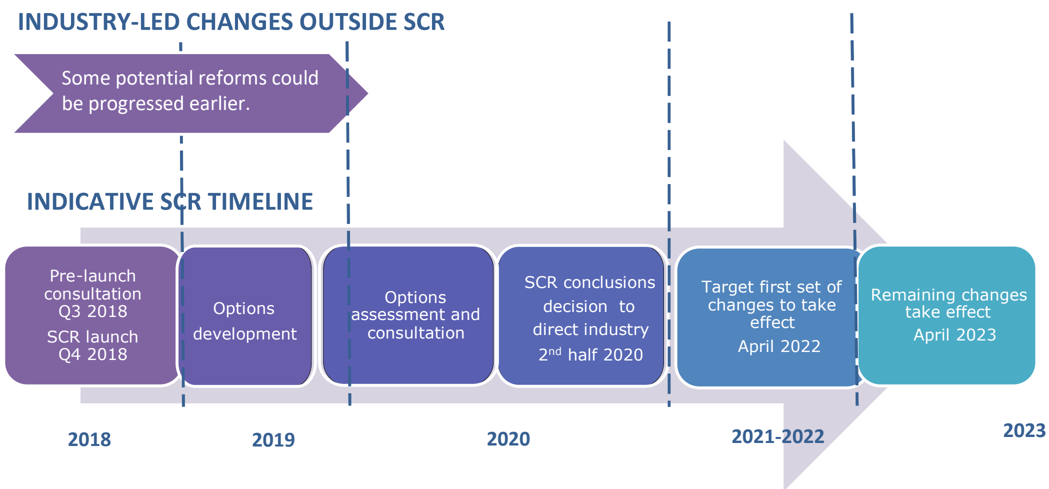
5.29. We recognise that the scale and complexity of potential change requires sufficient time to develop and fully appraise options. However, we are keen to implement any reforms needed on priority areas in a timely manner to maximise consumer benefit.

5.30. In particular, we are ensuring that the interactions with the price control are reflected in our proposed implementation timescales. Any change to the connection charging boundary will have a significant impact on RIIO-ED2 and would be signalled to the DNOs in line with the ED2 Strategy Decision.

5.31. Below we outline the timeline we expect the project to follow if we were to proceed with an SCR as proposed in this consultation. We will consider the later stages in light of consultation responses received, and the ultimate scope of review. Notably:

- We intend to make a decision and launch an SCR by the end of 2018
- We expect to have interim conclusions on industry's developing thinking on larger users' allocation and, if applicable, access definition workstreams in 2019. If we launch an SCR under a moderate scope, we would aim to achieve this timescale as part of our work with a central role for industry, though the conclusions could only be finalised as part of the conclusions of the whole SCR. If these workstreams were led by the ESO or network operators outside of a narrow SCR scope, we would expect them to have concluded their review by early 2020.
- We aim to conclude the process and, if we consider code changes are necessary, issue a direction to the relevant licensees to raise modification proposals as part of our SCR conclusions in the second half of 2020
- We target having the first set of changes to be implemented by April 2022 and the remaining changes to take effect by April 2023. We would consider any need for transitional arrangements as options for reform are developed.

Figure 4: Proposed Review timeline



Ensuring coordination and effective stakeholder engagement

5.32. Coordination across workstreams will be important, particularly where some areas are taken forward under an SCR where the ESO and network operators lead work on others outside of the SCR scope. It will also be crucial to ensure that wider stakeholders are able to understand and engage with the development and appraisal of policy options.

5.33. As part of running an SCR, it would be essential that we get adequate industry input and engagement to develop the options. We expect to consult at key stages but also use other routes. This is likely to involve continuing with one or more industry task forces as well as wider engagement with industry through the Charging Futures infrastructure, facilitated by the ESO as Lead Secretariat. We envisage that there would be a strong role in ensuring delivery and coordination for:

- The Charging Futures Forum (CFF), which brings together the various ongoing and emerging reviews of electricity access and charging arrangements into a joined-up work programme. The CFF has a central role in keeping stakeholders up-to-date and gives them the opportunity to influence the work undertaken. We see this as a key forum for ongoing engagement on policy option development and appraisals outside of formal consultation processes.
- The Charging Delivery Body (CDB), made up of the DNOs, the ESO, three code administrators and chaired by us. Its purpose is to help coordinate the development and implementation of required changes to electricity

network charging and access arrangements, to ensure successful delivery of the work programme needed to deliver these changes.
- Task Forces – we consider there is likely to be a role for Task Forces to support our work, and potentially that of the ESO and network operators where they are leading. We highly appreciated the contribution of the Task Forces set up in our first phase of work. We will consider the extent to which a second phase of Task Forces might have value and how these would best be constituted.

We will also be considering how best to make use of and coordinate with other relevant bodies and initiatives, for example code panels and the ENA's Open Networks project.

Next steps

5.34. This consultation will close on 18 September 2018. Details for how to respond can be found in Appendix 1.

5.35. Following the publication of the consultation, the CFF lead secretariat will host consultation launch webinars. These will provide stakeholders with the opportunity to discuss the consultation and enable us to gather initial reactions and feedback. There will also be a series of podcasts focussing on different stakeholder groups. For further details, please check the Charging Futures website at http://www.chargingfutures.com/.

5.36. We intend to hold a workshop at the next CFF meeting on 5 September 2018 to give stakeholders the opportunity to input and share their views ahead of the consultation closing.

5.37. We aim to make a decision on the scope of the review and launching an SCR by the end of the year, following consideration of responses to this consultation.

5.38. If we were to proceed with launching a SCR, we would publish a statement on our website (the launch statement), and aim to highlight this to the code panels that we expect to have an interest in the SCR. The statement is likely to include the reasons for launching and scope of the SCR, the process option to be followed and expectations of any areas were we expect the ESO/network operators to lead. The information set out in this statement might change during the SCR process.

Appendices

Index

Appendix 1 – How to engage with this consultation

How to respond

1.1 We want to hear from anyone interested in this consultation. Please send your response to the person or team named on this document's front page.

1.2 We have asked for your feedback in each of the questions throughout. Please respond to each one as fully as you can.

1.3 We will publish non-confidential responses on our website at www.ofgem.gov.uk/consultations, and put it in our library.

1.4 Please send us your response by close of business on 18 September 2018, and send them to:

Jon Parker, Head of Electricity Network Access
NetworkAccessReform@ofgem.gov.uk

Your response, data, and confidentiality

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

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

1.7 If the information you give in your response contains personal data under the General Data Protection Regulations 2016/379 (GDPR) and domestic legislation on data protection, the Gas and Electricity Markets Authority will be the data controller for the purposes of GDPR. Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. Please refer to our Privacy Notice on consultations.

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

➔ **Question 1:** Do you agree with the case for change as set out in chapter 2? Please give reasons for your response, and include evidence to support this where possible.

➔ **Question 2:** Do you agree with our proposal that access rights should be reviewed, with the aim to improve their definition and choice? Please provide reasons for your response and, where possible, evidence to support your views.

➔ **Question 3:** Specifically, do you have views on whether options should be developed in the following areas as part of a review? Please give reasons for your response, and where possible, please provide evidence to support your views:

a) Establishing a clear access limit for small users, with greater choice of options (as considered under b) and c) below) above a core threshold – do you agree with our proposal in paragraphs 3.5-3.10 that this should be considered? Do you have views on how a core threshold could be set?

b) Firm/non-firm and time-profiled access – do you agree with our proposal outlined in paragraphs 3.15-3.21 that these options should be developed?

c) Duration and depth of access, discussed in paragraph 3.25-3.32 - would these options be feasible and beneficial?

d) At transmission or distribution in particular, or are both equally important – as discussed in this chapter?

➔ **Question 4:** Do you agree with the key links between access and charging we have identified in table 1? Why or why not? Do you think there are other key links we have not identified? Where possible, please provide evidence to support your views.

➔ **Question 5:** Do you agree with our proposal that targeted areas of allocation of access should be reviewed? Please give any specific views on the areas below, together with reasons for your response. Where possible, please provide evidence to support your views:

a) Improved queue management as the priority area for improving initial allocation of access, as outlined in paragraphs 3.41-3.44?

b) Not to consider the potential role of auctions for initial allocation of access as part of a review at this time, as discussed in paragraph 3.44?

c) To review the areas outlined in paragraphs 3.45-3.48 to support re-allocation of access?

➔ **Question 6:** Do you agree that a comprehensive review of forward-looking DUoS charging methodologies, as outlined in paragraphs 4.3-4.7, should be undertaken? Please provide reasons for your response and, where possible, evidence to support your position.

➔ **Question 7:** Do you agree that the distribution connection charging boundary should be reviewed, but not the transmission connection boundary? Please provide reasons for your response and, where possible, evidence to support your position.

➔ **Question 8:** Do you agree that the basis of forward-looking TNUoS charging should be reviewed in targeted areas? If you have views on whether we should review the following specific areas please also provide these:

a) Do you agree that forward-looking TNUoS charges for small distributed generation (DG) should be reviewed, as outlined in paragraphs 4.19-4.23?

b) Do you consider that forward-looking TNUoS charges for demand should be reviewed, as outlined in paragraphs 4.24-4.27?

Please provide reasons for your response and, where possible, evidence to support your position.

➔ **Question 9:** Do you agree that a broader review of forward-looking TNUoS charges, or the socialisation of Connect and Manage costs through BSUoS at this time, should not be prioritised for review? Please provide reasons for your response and, where possible, evidence to support your position.

➔ **Question 10:** Do you agree that there would be value in further work in assessing options to make BSUoS more cost-reflective, and if so, that an ESO-led industry taskforce would be the best way to take this forward?

➔ **Question 11:** What are your views on whether Ofgem or the industry should lead the review of different areas? Please specify which of SCR scope options A-C you favour, or describe your alternative proposal if applicable. Please give reasons for your view.

➔ **Question 12**: Do you agree with our proposal to launch an 'Option 1' SCR for areas of review that we lead on? Please give reasons for your view.

➔ **Question 13:** Do you agree with the introduction of a licence condition on the basis described in paragraphs 5.11 and 5.12 and Appendix 5? Why or why not? Do you have any comments on the key elements set out in table 7 of Appendix 5a, or consider there are any other key elements which should be included? Please give reasons for your view.

➔ **Question 14:** Do you have any comments on the draft wording of the outline licence condition included at Appendix 5b? Please give reasons for your view.

➔ **Question 15:** What are your views on our indicative timelines? Do you foresee any potential challenges to, or implications of, the proposed timelines and how could these be mitigated?

➔ **Question 16:** What are your views on our proposals for coordinating and engaging stakeholders in this work?

Appendix 2 – Policy options

Table 3 – Summary of proposals for network access arrangements

Policy area	Proposed priority areas to review	Proposed approach to taking forward review	Potential intervention / codes affected
Examining options to clarify access rights and choices for small users, including households	We consider that there could be benefits from introducing a "core" level of access for small users, with options to obtain additional different types of access above this	Within the scope of an Option 1 SCR, with strong role for the industry to support options development and analysis	DCUSA
Improving definition and choice of access for larger users.	We consider that there may be benefits in improving the definition and choice of: • Firmness of access rights • Time-profiled access rights We are seeking views on whether there is value in improving the definition and choice in the • Duration of access rights • Depth of access rights	Either within the scope of an Option 1 SCR or alternatively industry-led outside the scope of an SCR	Distribution Connection Use of System Agreement (DCUSA) Connection Use of System Code (CUSC)
Improving allocation of access rights, including enhanced scope for markets	We consider that there may be benefits in establishing mechanisms to: • Enable those with non-firm access to trade it with others to reduce curtailment • Enable the exchange of access rights between network users • Introduce 'use it or lose it' conditions or capacity-based charging to incentivise users to release spare capacity • Improve queue management	Either within the scope of an Option 1 SCR with strong role for the industry to support options development and analysis or alternatively industry-led outside the scope of an SCR	DCUSA CUSC

Table 4: Summary of proposals for forward looking charges

Policy area	Proposed priority areas to review	Proposed approach to taking forward review	Potential intervention / codes affected
A comprehensive review of distribution forward-looking UoS charges	We consider that there may be benefits from improving the granularity and predictability of locational signals at distribution. We also consider that there may benefits in considering the balance between usage-based and capacity-based charges.	Within the scope of an Option 1 SCR, with strong role for the industry to support options development and analysis	DCUSA
Review distribution connection charging boundary	We will review whether it is in consumers' interest to move to a shallow connection charging boundary at distribution. We will also review the possibility of introducing user commitment requirements at distribution-level.	Within the scope of an Option 1 SCR, with strong role for the industry to support options development and analysis	DCUSA Each distribution licensee's own Connection Charging Methodology
Focused review of transmission forward-looking UoS charges	We consider that there may be benefits in aligning how distribution and transmission generation users are charged for their impact on the transmission network. We are seeking views about whether we should review the charging of demand under TNUoS.	Within the scope of an Option 1 SCR, with strong role for the industry to support options development and analysis	DCUSA CUSC

Appendix 3 – Summary of current arrangements

1.1 The basis on which a user’s access and charges for the network is established by a combination of provisions in legislation, codes, licences and associated methodologies, bilateral contracts or agreements. The overview provided in this document is not exhaustive or intended to be a definitive description, but rather a high level guide to some key features of arrangements, as context for the reader in considering our proposals in this paper.

1.2 We consider that there are key design parameters, or building blocks, that make up access and forward-looking charging arrangements. The building blocks outline the key possible choices for how these arrangements could theoretically be constructed. These apply differently to different voltage levels.

1.3 This Appendix provides gives an overview of the current arrangements, in relation to these building blocks.

Table 5: Building blocks of access and charging arrangements

Network access arrangements		Forward looking network charges	
Nature of access rights	Lifespan of access	**Structure of the charge**	Basis of the charge (fixed vs capacity vs volumetric)
	Time of Use access		Connection boundary
	Firmness		Ex ante or ex post
	Depth of access		Timing of payment and degree of user commitment
	Associated conditions of access (eg unused capacity)	**Location and temporal signals**	Locational signals
Allocation and reallocation	Initial allocation		Temporal signals
	Reallocation and trading (both medium/long term and near real-time)		Calculation of signals (ie cost models)

Network access arrangements

Nature of access rights

1.4 Network access is typically granted as part of a user gaining connection to the network. A user's access to the wider network can vary in its nature and conditions, such as level of firmness.

1.5 The more physically firm a user's access is, the lower the chance that the ESO or DNOs may have to curtail their connection. While financially firm access rights mean that, subject to certain rules, the ESO or DNO must agree payment with a user if it interrupts their access. Non-firm rights (or 'flexible connections') allow the ESO or DNO to interrupt the user's access without payment.

1.6 Larger generators have more explicit access to the transmission system - they agree their required Transmission Entry Capacity (TEC) as part of the connection process.

1.7 This access to the transmission system is more 'financially firm'[59] – these generators typically agree payments when their output is curtailed due to network constraints, up to the level of their agreed capacity. Eligibility for constraint payments is dependent on meeting network security standards set out in the System Quality and Security Standard (SQSS) and other conditions of their connection. The Connect and Manage regime enables generators to connect ahead of wider network reinforcements, if needed, and they can still be to agree payments if they need to be constrained.[60] The associated cost of these payments is socialised across other users.

1.8 Arrangements are different for Distributed Generators (DG). Distribution-connected generators do not have the same level of 'financially firm' access to distribution networks. Under a 'traditional' connection, curtailment is rare, typically only for outages due to maintenance. Where constraints exist, limiting the amount of capacity which can be offered on the network, new generators can opt for a 'flexible connection' from the DNO, rather than pay, or wait for reinforcement. This means their network access is interruptible and there is no payment if curtailed.

1.9 There is also not currently a clear security standard for DG. Partly as a result of this, DG do not have a clear understanding of their risk of curtailment. With flexible connections, the risk of their access being interrupted is higher and agreements are often open-ended.

1.10 For demand users, the situation is slightly different. Demand customers do not have an agreed transmission access capacity in the same way that larger generators do through TEC. However, larger distribution-connected demand customers are charged for access to the distribution network based on their specified capacity, which in effect reflects a well-defined access limit.[61] While transmission-connected demand may have faced connection charges which reflect the physical capacity of a site, but are not charged TNUoS on this basis, as discussed below.

1.11 Most small users – encompassing both demand and generation - in contrast, do not currently have a well-defined access level to the wider system. In practice, most are only limited by their fuse size and may never have considered or 'chosen' the level of access they require.[62]

1.12 For all types of user, the most common approach is that access rights are provided on a continuous, year-round basis. While larger generators can secure short-term TEC, of periods less than a year, this is not commonly taken up and contracts do not typically have a defined end date.

1.13 The depth of access rights, such as DG's ability to access the transmission network, is not typically explicitly defined. However, if a user has a connection to either the distribution or transmission networks then in practice they are able to access the wider network and markets. Some flexible connection arrangements may at times limit this in practice, but limits are typically defined by time restriction rather than depth.

[59] In this document, we use the term 'financially firm' to indicate that payment is generally available 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.

[60] Generators are not eligible for payment for local constraints if they connect ahead of "enabling works" needed to enable their full capacity. In some cases, generators have still connected ahead of these works being completed but payment is not available if the ESO curtails them due to associated constraints.

[61] This applies to customers whose size of connection is above that which needs a CT meter to measure. A CT meter is a meter that is used in conjunction with a Current Transformer.

[62] Currently households generally use much less than the limit provided by their fuse, particularly over sustained periods. This has been reflected in the amount of network capacity that has been built. If there was a widespread increase in peak household usage (while still remaining under the level of the fuse) this would result in the need for significant reinforcement of the network in many areas.

Allocation of access rights

1.14 Across both transmission and distribution, access is allocated through the connections process, on a first-come-first-served basis. Where access is not immediately available, in areas where there are network constraints, then "connection queues" can develop for access. The DNOs and SO undertake, or are developing proposals to undertake, 'queue management' activities to reduce the length of queues which develop - eg parties commit to demonstrating progress against development milestones to retain their position in the queue.

1.15 Where DG with flexible connections are curtailed the DNOs do this on a 'last-on-first-off' or pro-rated basis. This is typically established prior to their connection, though the overall level of curtailment is typically at the discretion of the DNO. The Balancing Mechanism (BM) provides a more market-based approach for determining which party curtailed to manage transmission constraints, with parties submitting bids to indicate their respective costs for adjusting their usage.

1.16 The Connect and Manage regime enables earlier, financially firm access to the transmission system, ahead of works needed to relieve wider transmission network constraints, with those constraints being managed operationally in the BM. Generators connecting under this regime are eligible, alongside others, to receive constraint payments if they are curtailed to resolve these constraints.

1.17 In relation to reallocating access rights, at transmission there is some limited scope to exchange 'TEC'. However, these provisions are not widely used.[63] There are no established arrangements for reallocating capacity at distribution, beyond the connections process.

Forward-looking charges

1.18 The revenue collected from connections and charging codes is considerable, around £10bn per annum (see breakdown in table 6). The revenues in the scope of this project (connection and forward-looking charges on the transmission and distribution networks) is around £5bn. This is ultimately paid for by consumers.

Table 6: Network connection and Use-of-System charging revenues in 2017/18

		Transmission	**Distribution**	**Balancing**
Connection		£0.1bn	£0.5bn*	-
UoS	Forward-looking	£0.5bn	£4.0bn	£1.2bn**
	Residual	£2.1bn	£1.4bn	
Total charges		£2.7bn	£5.8bn	£1.2bn

[63] Temporary TEC exchanges are provided for under the CUSC in some circumstances. Users must request an exchange rate from the ESO to transfer TEC between parties.

*2016/17 figures

**We note that currently BSUoS largely functions as a cost recovery than forward-looking charge.

1.19 There are three types of electricity network charge:

1. Connection charges
2. Distribution and Transmission Use-of-System (TNUoS and DUoS) charges
3. Balancing Use of System (BSUoS) charges

Connection charges

1.20 Connection charges recover some of the incremental cost of providing a user with a new or increased connection to the network (with the remaining costs recovered through UoS charges). Connection charges are calculated at the point of the connection request, based on the work required to provide the maximum export/import capacity requested by the connection party. Connection customers pay a site-specific connection charge, as calculated by the relevant licensee. Connection charges are therefore highly locational at both transmission and distribution. The connection boundary is different on the transmission compared to the distribution system.

1.21 At distribution, there is a 'shallow-ish' connection boundary - this means that a new connection customer pays for their own sole-use connection assets and contribute towards the costs of any wider network reinforcement (up to one voltage level above their connection or up to the GSP). Customers have to pay their connection charge in advance of the connection being energised. This upfront payment reduces the risk that the user's requirements change and assets become stranded.

1.22 At transmission there is a 'shallow' connection charging boundary, so the connection customer only pays for the sole-use assets needed to connect the customer to the network and not any wider reinforcement (though UoS charges also include locational charges – see below). Customers can pay the connection charge upfront or spread payment over 40 years. To reduce the risk of stranded assets, users make a commitment to their future payments (eg by providing security to cover any outstanding costs that they are directly liable for).

Use of system charges

1.23 TNUoS and DUoS are annual charges that recover the transmission owners (TOs) and DNOs' allowed revenues, determined by their price control settlement, to develop, operate and maintain their networks. TNUoS and DUoS charges are recovered from network users on an ongoing basis.

1.24 For TNUoS, the forward-looking element is produced using a model of flows across the transmission network that gives different tariffs for different zones ("load flow modelling"). Larger generators' charges are based on their agreed TEC, whereas demand and the majority of small DG are charged based on their consumption or generation during certain periods. Charges can be positive or negative (ie a credit), and most small DGs' charges are capped at zero.

1.25 DUoS has two charging methodologies:

- The Extra high voltage Distribution Charging Methodology (EDCM) which is also based on network load-flow modelling. It provides highly specific locational charges for those connected to the extra high voltage distribution networks.

- The Common Distribution Charging Methodology (CDCM), is based on a generic network model for each DNO region and so does not provide specific locational charges.

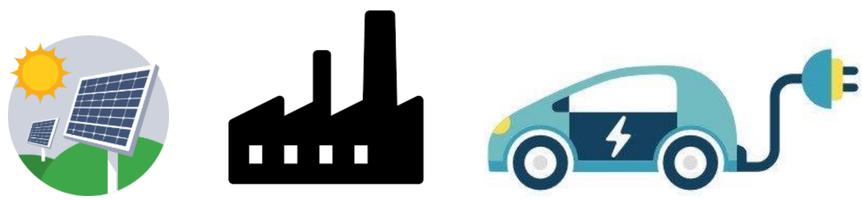
1.26 DUoS charges are based on a mix of usage charges (include some with differentiated time of use rates), agreed capacity charges and fixed charges. Under the CDCM, an average of 80% of UoS charges are recovered via usage charges. Under the EDCM, an average of 86% of charges are recovered via capacity charges. Generators can receive credits, rather than charges, even in generation-dominated areas. In the EDCM these are location specific whereas under CDCM they are paid as default.

1.27 BSUoS charges recover the ESO's costs of operating the system. A significant proportion of these costs (35%, 2017/18) relate to transmission constraint management; these costs need to be included when considering how we provide effective signals to users about network costs. BSUoS charges are charged to both larger generators and demand on a half-hourly basis, and are based on the volume of energy put onto or taken off the transmission system in that time.

Appendix 4 – Illustrative case studies

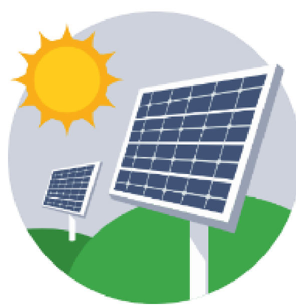
1.1 These illustrative case studies are intended to explain the potential impacts of the proposed options for reform on different types of typical network user, and how the potential reform could improve their access to, and use of, the network. The case studies presented are for the following:

- A large distributed solar generator
- A commercial customer with onsite generation
- A domestic user seeking to install an EV connection



1.2 As part of our further work, we will do additional analysis to better understand how the reform options will affect different network users.

Case study 1: A large distributed solar generator



1.3 In this example, a solar generator is seeking connection to the distribution network in a generation-dominated area with network constraints. Due to the volume of DG connected to the local network, the DNO has to curtail DG output at certain times and the distributed network frequently exports power onto the transmission network.

Current arrangements and issues

1.4 Under the current regime, the DNO can provide a connection offer for a 'standard' connection (with a very low chance of being curtailed) or a 'flexible connection' (where curtailment is open-ended).

1.5 Under a standard connection offer the user is liable for a proportion of the reinforcement costs, which could be significant. The reinforcement may also delay the connection date.

1.6 Alternatively, a 'flexible connection' offer allows the connecting customer to avoid its contribution to reinforcement costs, in exchange for providing open-ended curtailment without the opportunity to agree a payment. 'Flexible connection' offers have underlying principles which define the order in which curtailment occurs (eg 'last in, first off'). The DNOs provide an estimated curtailment rate, but no cap is defined on the level of curtailment that can be incurred.

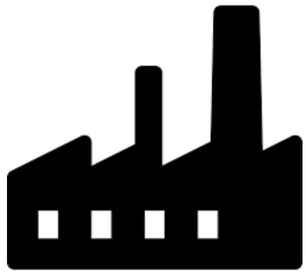
1.7 As distributed generation, this generator won't pay DUoS charges, but receives the charges as credits. The rationale is that it nets off demand and so, historically, would reduce pressure for new network capacity. Yet this occurs regardless of location - so in an area where DG is driving network reinforcement costs, the DG still receives this UoS credit. The generator also does not pay any TNUoS charges, even if DG is driving local transmission constraints.

Relevant options for reform

1.8 Our potential options for reform could have the following impacts on the generator:

- **Improving access choice and definition for larger users** could provide additional options for the generator to choose from:
    - Time-profiled access could allow a solar generator quicker or cheaper access if it is in an area that is constrained due to thermal generation, as it could allow them to exploit spare network capacity outside of winter peak periods.
    - Improving the definition of non-firm rights and could include a cap on the amount of curtailment a flexible connection can face without the opportunity to agree a payment, or make this time limited (for example, when network upgrades mean they can be offered a fully firm connection). This would make curtailment risk much easier to manage for the user.
- **Improving the allocation of access rights, including enhancing the scope for markets** could enable DG with flexible connections to bid to not be curtailed with other generators or users (such as demand side response providers) being able to offer in services to help manage the constraints. This would improve the efficiency of curtailment and make curtailment risk easier to manage for the user.
- **Focused improvements to the TNUoS charges** could mean DG paying charges in areas where they are contributing to transmission costs. They could continue to receive credits where they are providing benefits to the transmission system.
- **A comprehensive review of DUoS charges** could improve locational signals at the lower distribution voltages and improve cost reflectivity. In areas where DG is the driver of network reinforcement costs, DG could face a UoS charge, and in areas where it provides benefits to the distribution system, then it could receive a credit.
- **Reviewing the distribution connection charging boundary** could mean that reinforcement costs would no longer be focused on new connectees, instead these costs could be signalled to a wider group of network users via UoS charges.

Case study 2: Commercial customer with onsite generation



1.9 In this example, a large demand user with the ability to participate in demand-side response, is seeking connection to the EHV distribution network. It also has an onsite generator, which can meet most of its demand. The customer does not export onto the network.

Current arrangements and issues

1.10 Under the current regime, the customer has no or limited choices in terms of its access option.

1.11 Since the customer is connecting to the EHV network, if the connection requires reinforcement of distribution assets, then the connecting customer pays for the full cost of this through their connection charge. This cost can prove prohibitive for some users.

1.12 Once connected, DUoS charges are specific to the particular substation the user is connected to, which means they can be unpredictable, quite volatile and hard to respond to. The DUoS charge will be based on a combination of capacity and usage charges. TNUoS charges are general across the DNOs region they are located in, and will be based purely on the user's demand during triad periods. This demand is calculated net of any generation by the user during those periods.

Relevant options for reform

1.13 Our potential options for reform could have the following impacts for this user:

- **Improving access choice and definition for larger users** could provide additional options for the user to choose from:
    - The development of **time-profiled access** could allow the user to choose an option that clearly defines an access right for a specific time window, in return for a discounted UoS charge. The connecting customer could then use onsite generation to ensure that their metered demand matches the time-profiled access right.
    - Alternatively, they could choose a cheaper, **non-firm** access right, and when interrupted, use their onsite generation.

- **A comprehensive review of DUoS charges** could improve the predictability of their EHV UoS charges, for example by moving towards an approach that is more like TNUoS charging (that has zonal rather than site-specific charges).

- **Reviewing how TNUoS demand charges are calculated** could mean their charges based on net demand during fixed time of use periods or based on an agreed the latter option lead to greater consistency between how the onsite generator and standalone generators are treated.

- **Reviewing the distribution connection charging boundary** could involve a change to the connection boundary so that the connecting party's connection charge only covers sole-use assets and not wider reinforcement. This would align the distribution connection boundary with that at transmission.

Case study 3: Domestic user seeking to install an EV connection

1.14 In this example, a domestic household with a smart meter, is looking to install a home EV charging point.

Current arrangements and issues

1.15 The increased deployment of LCTs (eg EVs and heat pumps), may increase consumption of electricity on the LV network and create the need for reinforcement. Current UoS charges do not reflect the extent to which choices of when (peak or off-peak), where (unconstrained or constrained network) and how (eg fast or trickle charging).

1.16 For example, the existing domestic customer's UoS charges would not reflect any avoided reinforcement costs if they decided to charge at off-peak times. The current UoS charges would also not reflect any reduction in reinforcement costs if the customer decided to install a slow EV charger, rather than a fast EV charger.

Relevant options for reform

1.17 Our potential options for reform could have the following effects for this user:

- **Clarifying access rights and choices for smaller users, including households** could help ensure that access charges reflect user's requirements. Households, or suppliers on their behalf, need to nominate what capacity they require. This would be set at a minimum amount that would allow users' basic needs. An EV owner would likely need to nominate a higher capacity level in order to be able to charge their vehicle. There would be different choices around this – if they were willing to only charge off-peak, have their charging managed by their DNO or opt to slow charge over fast charging then 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 the need to reinforce the network.

- **A comprehensive review of distribution use of system charges (DUoS)** would complement the above, as it could make charges more based on users' specified access requirements and introducing sharper signals (eg more locational granularity) for higher usage could also mean those users driving new network investment would pay a larger portion of these costs.

Appendix 5 – Key provisions and outline text of the proposed new licence condition[64]

Appendix 5a – Overview of proposed licence requirements

1.1. The licence conditions we are proposing to introduce would cover the following key elements and we are seeking views on these. Nb this would not apply if we were to proceed with a 'comprehensive' SCR – scope C.

Table 7: Outline of proposed licence provisions

Element	Outline of proposed requirements
1. Objectives of the licence condition	We propose to introduce licence requirements to provide assurance of timely industry-led progress to develop and, where applicable, implement reform to the areas of arrangements set out below, where these will deliver benefits for consumers.
2. Parties the proposed condition(s) would apply to	We are proposing to introduce these obligations under a new standard licence condition in the following parties' respective licences: • DNOs (excluding IDNOs) – ie for inclusion in Part B of the Electricity Distribution Licence • The ESO We consider the ESO is well placed to reflect the transmission system perspective, coordinating wider input from Transmission Owners as needed, but welcome views on this position.
3. Required outputs	The licensees would be required to, jointly with other licensees: a) Develop and assess options for reform in the specified areas (see element 4 below), where it expects these to deliver benefits for consumers; b) Implement any reforms that arise out of a) above that it finds are expected to be beneficial for consumers or, where code modifications would be required, develop and raise robust,

[64] Subject to our decision on the scope of review and SCR following this consultation.

	well-evidenced Code Modification Proposal(s) to the relevant code Panel(s) (or parties in the case of DCUSA), and participate constructively in the industry process to develop Final Modification Reports; c) Report to the Authority on its initial conclusions, recommendations for areas to be considered in the proposed SCR *[subject to final decision]*, and how it has met the requirements of this condition, with accompanying draft and final impact assessments.
4. Scope of areas of arrangements considered	The final scope of arrangements to be considered would be set out in the Authority's decision on the proposed review. Our current minded-to position, in line with the options for scope described in Chapters 3 and 4 of this consultation, are that the proposed new obligation would require licensees to deliver the above outputs in relation to the following areas of arrangements: *If we decide to launch an SCR with a Moderate scope as described in Chapter 5 of this consultation:* a) **Mechanisms for the allocation and reallocation of access**, focused on the potential to deliver benefits through establishing mechanisms to: i. Improve management of the connections queue ii. Enable the exchange of access rights between network users; iii. Enable those with non-firm access to trade it with others to reduce their curtailment; iv. Introduce 'use it or lose it' conditions; **AND** *If we decide to launch an SCR with a Narrow scope as set out in Chapter 5 of this consultation, licensees would additionally be required to review:* b) **The definition and choice of access,** focused on the potential to deliver improvements through improving the definition and choice of access rights for Large Users[65], in relation to their i. Time-profile, short term duration and firmness **AND**

[65] See Appendix 7 – Glossary and defined below

	ii. *Potentially also, depending on the outcome of this consultation:* Long term duration and depth.
5. Timescales for delivery	Licensees would be required to deliver the outputs set out above on the following timescales, with the provision for Ofgem to amend these as needed: a) An Interim Report and any Code Modification Proposals needed, with accompanying draft impact assessment submitted by 30 June 2019; b) A Conclusions Report and any Final Modification Reports submitted, and any reforms which do not require code changes implemented by 31 March 2020.
6. Approach to delivery and quality of outputs	In delivering these requirements, licensees would be required to collaborate and engage constructively with wider stakeholders and deliver these requirements jointly with other DNOs and the ESO. It must seek to deliver robust, well-evidenced proposals which consider the wider existing frameworks and developments in the industry in a timely manner.
7. Other key provisions	a) A requirement that the licensee must demonstrate its compliance with this condition on request of the Authority b) A provision for the Authority to issue derogations to the requirements of this condition, subject to consultation with materially affected parties, for a specified period of time and subject to conditions. c) A provision for the Authority to change the Implementation Dates. d) A provision for the Authority to issue guidelines or direct licensees in relation to their development and assessment of options. (Nb this does not provide for the Authority to direct that specific code modifications should be raised).

Appendix 5b – Illustrative draft outline licence condition

1.2. We include below an outline draft of the licence condition we are proposing to introduce.

This licence condition would be introduced for DNOs (excluding IDNOs) and the ESO

The below draft condition is provided for consultation purposes only, as an illustration of how the key elements in Appendix 5a above could be implemented.

Condition [X]: Reform of network access and forward-looking charging arrangements

Introduction

1.1. The purpose of this condition is to ensure that the licensee reviews priority aspects of current energy system arrangements as identified in this condition and develops reforms where needed to deliver benefits for consumers.

1.2. This condition requires the licensee to:

(a) review defined aspects of access arrangements; and

(b) as needed, develop and take forward reform proposals to achieve significant improvements in these arrangements to deliver benefits for consumers.

1.3. The licensee must deliver timely and effective reform proposals in the manner set out in this condition, to deliver consumer benefit to the greatest extent that is reasonably practicable, working collaboratively with other Distribution Services Providers and the Electricity System Operator, and consulting the wider industry.

Outputs

1.4. The licensee must comply with the scope, outcomes and timescales identified (or subsequently modified) by the Authority to identify and take forward beneficial changes in areas of reform of Relevant Arrangements as set out in this condition.

1.5. The licensee must:

(a) develop and assess options for reform the licensee considers will best deliver improvements to the existing Relevant Arrangements as outlined in paragraph 1.12 which it expects would deliver benefits for consumers to the greatest extent reasonably practicable, while ensuring an efficient, economical and coordinated system and meeting the reasonable needs of customers;

(b) Progress the implementation of any options that arise out of a) above, which it expects to deliver benefits for consumers, as follows:
   (i) Implement any such options identified, where this can be done without modifications to codes;
   (ii) Where code modifications would be required to implement any such beneficial options identified by the licensees the licensee must:

a. develop and submit one or more change proposals, as needed to the relevant code panels (or parties in the case of DCUSA)
b. facilitate the implementation of these proposals by the preparation and submission of a modification report so that the panel is able to vote for the implementation or rejection of the proposed modification.

(c) Submit to the Authority:

(i) an Interim Report setting out the scope of reform it has identified and considerations on how it should be progressed, with its views on the proposals. This Report includes an initial impact assessment of the options considered and a recommendation for those reform options which it considers relevant to the options being considered by Ofgem under the scope of its SCR *[subject to final decision]*; and
(ii) a Conclusions Report setting out the final conclusions of its assessment as required under 1.5 a) and those reform options selected for implementation under 1.5 b) of this condition, including an impact assessment of the options progressed.

1.6. In developing and assessing options for reform under paragraph 1.5, the licensee should have regard to relevant code objectives, its other existing duties, wider developments within the Significant Code Review on Access and Forward looking charging *[subject to final decision]*, any guidelines or direction from the Authority issued under paragraph 1.10. – 1.11. of this condition, and any other factors it considers relevant in the interests of consumers;

1.7. Its recommendation and conclusions should consider the potential to deliver benefits for consumers in the round, including considering costs, proportionality and practicality of implementation, and the implications of consistency and integration with the arrangements being considered under the Significant Code Review on Access and Forward looking charging *[subject to final decision]*.

Approach

1.8. The licensee, in performing its duties required under this condition to deliver the outputs set out in paragraph 1.4. – 1.7. must:

(a) undertake these duties jointly, in conjunction with every other Distribution Services Provider and the Electricity System Operator.;
(b) take all reasonable steps to collaborate and engage constructively with wider stakeholders, which may include, as needed, to:
   (i) share and obtain information, in order to undertake the necessary development and assessment of options for reform and develop its conclusions proposals;
   (ii) develop its assessment and proposals in consultation with any other persons whose interests are materially affected by the Relevant Arrangements;
   (iii) promptly escalate and/or resolve any disputes or barriers identified that if unresolved may jeopardise the fulfilment of these obligations and the delivery of the expected outcomes within the expected timescales, seeking guidance from the Authority as it considers necessary.

(c) develop the requirements of this condition in a timely and efficient manner and by not later than the Implementation Date or such other date as directed by the Authority;
(d) take all reasonable steps to ensure its code modification proposals for reform will be capable of being approved.

Implementation Dates

1.9. The licensee must deliver the requirements of this condition by the Implementation Dates set out below, or as subsequently modified by the Authority:

(a) The Implementation Date by which the deliverables required under paragraph 1.5 a), 1.5 b) (i) and (iii) and 1.5 c) ii) must be completed is 31 March 2020;

(b) The Implementation Dates by which the deliverables required under paragraph 1.5 b) (ii) and 1.5 c) i) of this condition must be submitted to the Authority are:

(i) For the Interim report, 30 June 2019;

(ii) For the Conclusions Report, 31 March 2020.

Guidelines and direction

1.10. The Authority may issue further guidelines to the licensee on its review and reform of the Relevant Arrangements identified in paragraph 1.12.. The Authority will conduct a consultation, for a minimum of 28 days, before any guidelines are issued;

1.11. If the Authority considers that the licensee has not paid due regard to the guidelines then it may direct the licensee to review the areas identified in paragraph 1.12. and take forward the development and assessment of proposals for reform in the manner specified in the direction. The Authority will conduct a consultation, for a minimum of 28 days, before any direction is issued.

Relevant Arrangements

1.12. The Relevant Arrangements encompass the following aspects of arrangements and potential areas for reform:

(a) **Mechanisms for the allocation and reallocation of access:** The licensee must consider the potential to deliver consumer benefits through improvements to allocation and reallocation mechanisms, considering enhancing the use of market mechanisms and how arrangements can provide better signals about the value of network capacity. The licensee must consider in its review the potential to deliver benefits through establishing mechanisms to:

(i) Improve processes for managing the connections queue.
(ii) Enable the exchange of access rights between network users;
(iii) Enable those with non-firm access to trade it with others to reduce curtailment;
(iv) Introduce 'use it or lose it' conditions on access, also considering the potential role for capacity-based charging as incentives to users to release spare capacity;

Additional paragraph if we launch an SCR with a Narrow scope as set out in Chapter 5 of this consultation:

(b) **The definition and choice of access:** The licensee must focus its review on the potential to deliver consumer benefits through improvements to the definition and choice of options for time-profiled, short term duration and firmness of access rights for Large Users.

Subject to the outcome of this consultation, potentially also: and improving the definition and choice in the duration of access rights and depth of access rights.

Compliance with this condition

1.13. The Authority may (after consulting with the licensee and, where appropriate, any other materially affected party) issue a direction requiring the licensee to demonstrate compliance with this licence condition in a manner specified by the Authority.

Derogations

1.14. The Authority may (after consulting the licensee and, where appropriate, any other materially affected party) issue a direction ('a derogation') to the licensee that relieves it of its obligations under this condition to such extent, for such period of time, and subject to such conditions as may be specified in the direction.

Duration of condition

1.15. Paragraphs 1.1. to 1.14. will cease to have effect on 30/12/2021 unless, following consultation, the Authority specifies a later date by publishing a statement in writing.

1.16. The power to specify a later date in paragraph 1.15. may be exercised by the Authority on more than one occasion (before, on, or after the expiry of any later date specified by the Authority).

Definitions

Distribution Service Provider	As defined in the existing Electricity Distribution Licence
Electricity System Operator	The national Electricity System Operator in GB, as defined in the Electricity Transmission licence.
Large Users	Those users of the distribution or transmission network who have an agreed capacity (eg the majority of users with current transformer metering), and transmission-connected users.
Code modification proposal	As defined in the relevant codes, a proposal, submitted to the appropriate code administrator, to modify the relevant code legal text or methodology, in order to address an identified issue.
Final modification report	As defined in the relevant code, the final modification or change report, which summarises the work completed and is submitted to the relevant code panel for voting, and to assist in the final decision.

Appendix 6 – Baringa's materiality rating framework

As part of their analysis, Baringa developed a materiality rating framework to allow for a more direct comparison of the areas of inefficiency in the current arrangements. Table 8 below summarises their approach.

Table 8: Baringa's materiality framework

	High	Medium	Low
Deployment barriers	Existing or potential constraints on deployment are very significant *Metrics: queue or constraint may delay connection of >2 GW for multiple years*	Existing or potential constraints on deployment are significant *Metrics: queue or constraint may delay connection of <2 GW for multiple years*	Existing or potential constraints on deployment are low *Metrics: limited or no queue / constraint*
Efficiency of operation	Impact on efficiency of operation is likely to be significant, and as a result of a number of closely linked issues *Metrics: potential annual system impact likely to be greater than £50mn*	Impact on efficiency of operations is likely to be significant in a specific area *Metrics: potential annual system impact likely to be between £10mn and £50mn*	Impact on efficiency of operations is likely to be low and specific to distinct area *Metrics: potential annual system impact likely to be less than £10mn*
Efficiency of investment	Impact on efficiency of investment is likely to be significant, and as a result of a number of closely linked issues *Metrics: potential impact likely to be greater than £400mn NPV to 2040*	Impact on efficiency of investment is likely to significant in a specific area *Metrics: potential impact likely to be between £100mn and £400mn NPV to 2040*	Impact on efficiency of investment is likely to be low and specific to distinct area *Metrics: potential impact likely to be less than £100mn NPV to 2040*
Allocation of risk	Allocation of risk is highly inefficient, and has the potential to lead to inefficient outcomes *Metrics: potential annual system impact likely to be greater than £50mn*	Allocation of risk is likely to be highly inefficient in a specific area *Metrics: potential impact likely to be between £10mn and £50mn annual impact*	Allocation of risk may be inefficient, but is confined to specific areas *Metrics: potential impact likely to be less than £10mn annual impact*

Appendix 7 - Glossary

This glossary is provided for the benefit of readers to assist in understanding some of the more technical elements of the consultation document. The definitions are provided explain how the terms are used in this document, and do not necessarily define the terms as used in other publications.

Term	Definition
BSUoS charges	The Balancing Services Use of System (BSUoS) charge recovers the cost of day to day operation of the transmission system. Generators and suppliers are liable for these charges, which are calculated daily as a flat tariff across all users. The methodology that calculates the BSUoS is set out in Section 14 of the CUSC.
CDCM	Common Distribution Charging Methodology (CDCM) for DNOs use of system charges at lower voltages.
Connect and Manage	The Connect and Manage transmission access regime was introduced by the government in August 2010 and implemented on 11 February 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.
Connection charges	Connection charges refer to the charges incurred when a new user connects to the network. They are paid for by the new users, and charged by the network operator (with transmission or distribution, depending on where the new user connects)
Constraints (on a network)	An electricity network is constrained when the required capacity to transport desired electricity flows is higher than the actual capacity on the network. Can also be referred to as network congestion.
Cost reflective charges	Cost reflective charges are charges (or elements of a charge) that are set to reflect the costs or benefits that a user confers on the network. These could be network investment or operational costs.
Curtailment	Curtailment refers to a user's ability to import or export from the network being restricted i.e. the users access to the network is said to be curtailed.
CUSC	The Connection and Use of System Code (CUSC) is the contractual framework for connection to, and use of, the National Electricity Transmission System
Demand Side Response	Demand side Response (DSR) refers to the ability of sources of demand (for example, and industrial process) to increase or decrease their demand in response to signals (sometimes price-signal) in order to support system or network management.

Depth of access	In this consultation, we refer to this as the extent to which a user has access rights to the electricity networks as a whole or only particular levels or geographic areas.
Distributed generation	Also called DG, embedded generation, and distribution-connected generation. These are generators connected to the distribution system, rather than the transmission system. Smaller (sub-100MW) DG do not pay transmission charges and can receive Embedded Benefits. Larger (over 100MW) DG do pay transmission charges and do not receive Embedded Benefits.
Distribution network	In England and Wales this is the wires, cables and other network infrastructure that operate at 132kV and below, while in Scotland it is the infrastructure that operate below 132kV. Distribution networks carry electricity from the high voltage transmission grid to industrial, commercial and domestic users.
Distribution Network Operator	Distribution Network Operator companies own, operate and maintain the distribution networks. They do not sell electricity to consumers, this is done by the electricity suppliers. There are 14 licensed distribution network operators (DNOs) in Britain, and each is responsible for a regional distribution services area.
Distribution Use of System Charges (DUoS) charges	These charges recover the DNOs allowed revenues under the price control settlements and are charged to demand users on the distribution network, while generators on the distribution network are treated as negative demand. They are broadly separated into forward-looking charges, which relate to the incremental cost of using the network in a specific location, and residual charges that recover the remaining costs and are non-locational.
EDCM	Extra High Distribution Charging Methodology (CDCM) for DNOs use of system charges at lower voltages.
Electricity network	The electricity network includes both the distribution network and the transmission network.
Electricity System Operator	The party (National Grid System Operator) with the responsibility for the minute-to-minute operation of the system and transmission network, ensuring it is balanced and stable.
Embedded generation	See 'distributed generation'
Energy system transformation	The Energy System Transformation refers to the process by which we are changing the energy system (including power, heat, and transport), from a system based on carbon intensive fossil fuels, to one based on low carbon technology.
Extra High Voltage	In this consultation, EHV refers to the extra high voltage infrastructure on distribution networks. These are distribution network assets with nominal voltages of at least 22kV.
Financial firmness	See 'Firmness'
Firm access	See 'Firmness'

Firmness	The more physically or technically firm a user's access is, the lower the chance that the SO or DNOs may have to curtail their connection. While financially firm access rights mean that, subject to certain rules, the SO or DNO must agree payment with a user if it interrupts their access. Non-firm rights (or 'flexible connections') allow the SO or DNO to interrupt the user's access without payment.
Flexibility	Flexibility refers to the ability of users on the network to quickly change their operations in order to provide system services, such as supporting system balancing and network constraint management. Sources of flexibility are demand side response, storage, and dispatchable generation.
Forward looking charges	The elements of network charges that signal to users how their actions can either increase or decrease future network costs. They typically provide signals about the costs or benefits of locating at different points on the network (sometimes called "locational charges") and/or of using the network at different times.
Half-hourly metering	A form of interval energy data. Some metering equipment can measure energy on a half hourly (HH) basis and where this is the case, network charges based on measures of usage within different half-hourly periods.
High voltage	Distribution network assets with nominal voltages over 1kV but less than 22kV.
Interface between transmission and distribution	Where we discuss the interface between transmission and distribution, we are referring to the fact that there are different regulations and charging methodologies across the networks. This creates 'interface issues' whereby the fact that there are different regulations may influence investment and operation decisions that don't necessarily reflect the underlying economics.
Large User	By large users, here, we are referring to those distribution-connected users who have an agreed capacity (eg the majority of users with current transformer metering), and transmission-connected users.
Larger generators	Those generators with a generating capacity greater than or equal to 100MW
Load flow modelling	A model of flows across the electricity network that gives different tariffs for different zones.
Local access	See 'Depth of access'
Local circuit tariff	TNUoS charges have two components – a wider network tariff and a local charge. Local charges are only paid by generators. The local circuit charge refers to the infrastructure between the location of the generator and the first connection to the Main Integrated Transmission System (MITs).
Low voltage	Distribution network assets with nominal voltages below 1kV.

Network access rights	Network access rights define the nature of users' access to the networks – how much they can import or export, when and for how long, where to/from, and how likely their access is to be interrupted and what happens if it is.
Network access arrangements	Network access arrangements refers to how the network access rights are allocated to users.
Network capacity	The amount of electricity flows that the network is able to accommodate.
Ofgem	Ofgem is the Office of Gas and Electricity Markets. Our governing body is the Gas and Electricity Markets Authority and is referred to variously as GEMA or the Authority. We use 'the Authority', 'Ofgem' and 'we' interchangeably in this document.
Off-peak demand	In this consultation, off-peak refers to the times when demands on the network are not at their highest (see Peak).
Peak demand (times, demand)	Peak refers to the times when demands on the network are highest. These times can vary in different parts of the network.
Physical firmness	See 'Firmness'
Shallow connection boundary	The depth of a connection boundary refers to the costs incurred by a connectee in cases where wider reinforcement of the network is required. 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.
Shallow-ish connection boundary	Under a shallow-ish connection boundary: - The connection customer will pay for their own sole-use connection assets. - The connection customer will contribute towards any wider network reinforcement required. This is in contrast to a deep connection boundary where the connection customer would pay for all wider network reinforcement costs required.
Significant Code Review	A Significant Code Review provides a tool for Ofgem to initiate wide ranging and holistic change and to implement reform to a code based issue, as introduced under the Code Governance Review - https://www.ofgem.gov.uk/licences-industry-codes-and-standards/industry-code-governance/code-governance-review.
Small users	By small users, here, we are referring to those users who do not have a specified capacity. These users are typically not CT metered.

Small generators	Those generators with a generating capacity less than 100MW.
Smart meter	A smart meter is an electronic device that records consumption of electric energy and communicates the information for the purpose of system monitoring and billing.
Transmission Network Use of System Charges (TNUoS)	These charges recover the TNOs allowed revenues under the price control settlements and are charged to both demand users and generators. They are broadly separated into forward-looking charges, which relate to the incremental cost of using the network in a specific location, and residual charges that recover the remaining costs and are non-locational.
Transmission Entry Capacity	Transmission Entry Capacity (TEC) is the allowed capacity a larger generator can export onto the network, as agreed in the connection agreement
Transmission network	The transmission network comprises of circuits operating at high-voltage, defined as 400kV, 275kV, and 132kV (in Scotland only). The system is responsible for the transmission of energy from generators to lower voltage distribution networks, which subsequently distribute the supply to users.
Transport Model	The Transport Model is the name of the charging methodology used to calculate the element of TNUoS charges that provides forward-looking signals about the impact of users on the wider network.
Triad periods	The triad refers to the three half-hour settlement periods with highest system demand between November and February, separated by at least ten clear days. National Grid uses the triad to determine TNUoS charges for customers with half-hour metering. The triads for each financial year are calculated after the end of February, using system demand data for the half-hour settlement periods between November and February.
Wider network tariffs	TNUoS charges have two components – a wider network tariff and a local charge. The wider network tariff reflects the incremental cost of power being added to the system at different geographical points.