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Reform of electricity network access and forward-looking charges: a working paper

Overview

Current and likely future trends in the energy system will transform how we use the electricity networks. We want to ensure consumers see the benefits and get value for money from the energy system. Electrification of heat and transport have the potential to increase peak demand on the system considerably, and this could lead to constraints in some parts of the networks. Changes to the location of generation sources, with the emergence of new low carbon and decentralised technologies, are already leading to constraints. There is a risk that limits on network capacity could hinder the ability for the system to accommodate new (often low carbon) technologies and changing usage patterns. The traditional solutions to this would involve network reinforcement, at potentially substantial cost to consumers.

Set against this, the emergence of smart technologies and new, innovative business models offer opportunities to adjust demand and supply at times and places where there are network constraints. This can significantly defer or reduce the network reinforcement which might be needed.

These trends and drivers mean that it is increasingly important that network capacity is allocated and used in a way which reduces the potential costs to consumers as a whole. The fact that transmission and distribution-connected generation are increasingly substitutable and in competition with each other also means that there is a growing need to ensure that the regulatory arrangements at different voltages do not create undue distortions to investment and operational decisions.

Our Strategy for regulating the future energy system and our Plan for a smart, flexible energy system (which is joint with government) described how providing users with better signals about the costs and benefits they confer on the network at a given time and place is a priority area. **This working paper launches the process by which we plan to address the key regulatory gaps in this area, working in conjunction with industry.**

We are focusing in this project on options to define more explicitly arrangements for access to the networks, and to improve the “forward-looking” elements of network charging. By forward-looking, we mean the element of network charges that looks to provide signals to users about how their behaviours can increase or reduce future costs on the network. We consider there is value in considering the approach on the following key building blocks for access and forward-looking charging arrangements:

<table>
<tr><th colspan="2">Network access arrangements</th><th colspan="2">Forward-looking charges</th></tr>
<tr><td rowspan="5">Nature of access rights</td><td rowspan="2">Time aspects</td><td rowspan="4">Structure of charge</td><td>Types of costs</td></tr>
<tr><td>Types of charge</td></tr>
<tr><td>Firmness</td><td>Basis of charge</td></tr>
<tr><td>Geographical nature</td><td>Timing of payment and degree of user commitment</td></tr>
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There are a number of areas where the current arrangements might need to be improved to drive more efficient outcomes. For many users, the current arrangements have limited explicit consideration of the nature of access rights being granted to the system. This means that there is no, or a poorly defined, choice of different access options available to fit users' needs, and they provide only limited information to help identify where new network capacity is needed. The allocation of access is generally on a first come first served basis, with rights not readily tradeable or transferable. As a result, some users may be disadvantaged in seeking to get access to the system and capacity may not be being used efficiently.

We also see a number of areas where charges may be insufficiently cost-reflective, covering both charges for generators and demand. In other areas the charges are highly cost-reflective but may be too volatile and undermine efficient investment. There are significantly different approaches taken across different voltage levels (between lower and extra-high voltages at distribution level, and between distribution and transmission level) which could distort investment and operational decisions, with a knock on effect on consumer bills.

In addressing these shortcomings, options to reform the nature and allocation of network access rights have the potential to offer significant improvements over current arrangements.

Creating more choice about how consumers and other users can gain access to the system, through allowing for well-defined options on the nature of access rights, offers the potential to allow them to optimise their access right (and the associated charges) according to their needs. This could result in more efficient use of the network and provide better information about how the network needs to develop. For example, a user who was willing to bear a certain level of interruptions to their network access at certain times could pay less as they would not be driving the same level of incremental network cost as those with an access right that entitles them to compensation when their access is interrupted. Other choices could be to buy a right to just be able to trade within a local area rather than across the national market, to have a choice between short-term and long-term rights, or peak and off-peak access.

Further options would be to move away from a first-come-first-served approach to one where access rights (covering a specified time period) are allocated in periodic windows, and/or to facilitate reallocation of access rights between parties. Both options could support more efficient allocation of access rights.

Different options might apply to different types of user. For example, all households might have a default access right to represent a reasonable "core" requirement. They could then need to purchase additional products for access beyond those default rights, with potential choices over whether that is peak or off-peak, or interruptible or not. A key question with such an approach would be how to define the core access requirements in the overall interests of consumers.

We also consider the key changes to the current approach to forward-looking charges which might be warranted. Options include:

- changing the basis of charges to be focused more on drivers of investment (eg maximum usage during constrained periods rather than total annual usage)
- increasing locational granularity in some network charges
- harmonising the approach taken across voltage levels to the extent that there are differences that could be materially distorting decisions)

We are considering whether changes might be merited to the approach for connection charges, Transmission Network and Distribution Use of System charges, and the approach to recovering costs for transmission constraint management through the

Balancing Services Use of System charge. Some of these options could involve changes to individual charges, while others could involve linked changes to two or more charges. If changes to access rights are taken forward, then some of these changes to forward-looking charges may still be required. However, there could also be a move to "access-based" rather than "usage" charges, akin to the move in telecommunications towards more payment for an allowance rather than payment per actual usage. There could also be scope to allow charges to be fixed where there are clear longer-term rights (with ongoing financial commitment to those rights from the user).

In considering potential changes, there is a need to recognise that the electricity networks exist to meet the needs of consumers, as appropriate for an essential service. This means that options that have significant distributional effects between consumers that cannot be justified by a reduction in overall costs (or achieving other objectives) are unlikely to be acceptable. The aim is for the network to meet the needs of users and the expectations of wider society as efficiently as possible.

We will also consider the extent to which the arrangements at transmission and distribution, and between generation and demand, should be aligned. This will need to balance ensuring that differences in the arrangements do not materially distort users' decisions with reflecting the varying circumstances of different types of user (and the impact they have on the networks). It will also need to take into account the scale of implementation costs with different options. More generally, we recognise that there will be a need to consider how existing users might be affected by some of these options, and whether there could be a case for transitional arrangements.

We are keen to gain a wide range of views to inform this work. We are setting up two taskforces under the new Charging Futures Forum[1] to help develop the options further. We will also be undertaking work to understand better the impact of the issues with the current arrangements. We intend to use the outcome of this work to inform our initial proposals for reform which, if needed, we expect to consult on next summer. We will also explain how we intend to take forward the reforms, including whether we propose to launch a significant code review.

This project is closely linked to our Targeted Charging Review. This is considering how the "residual" element of network charges should be recovered in a way that is fair and reduces distortions. There are also strong links between this project and our work on the role of the system operators, both at the transmission level and Distribution Network Operators as they increasingly take on Distribution System Operator roles, and with our wider RIIO-2 price control preparations. The roll-out of smart meters and market-wide half-hourly settlement are also closely linked as they will enable price signals to shift their consumption for households and small businesses to shift their consumption in response to system needs. Our overriding principle throughout is to ensure that the energy system works in the overall interests of consumers.

[1] The Forum's aim is to facilitate better coordination of charging arrangements and to keep stakeholders up-to-date and giving them the opportunity to influence the work undertaken – further information can be found here: https://www.ofgem.gov.uk/publications-and-updates/charging-futures-forum

Contents

1. Context and document purpose

Document purpose

1.1. This working paper describes our work to identify potential reforms to improve how capacity on electricity networks is used and developed. We set out our views on the issues with the current arrangements and initial thinking on the options to address these. These are deliberately wide-ranging, as we think the issues need to be considered systematically before potentially narrowing down on priority reform areas driven by what would have most value for consumers in general.

1.2. The intention of this paper is to kick-start work with industry and others to develop the options further. In particular, we are setting up two Task Forces under the Charging Futures Forum (CFF) to build on the ideas set out in this paper and develop and assess options. We will also be engaging more widely. We plan to use the outputs of these, alongside our own ongoing work, to set out and consult on initial proposals for reform (if needed) in summer 2018.

Why we are doing this now

Signals for the efficient use and development of the networks in a changing world

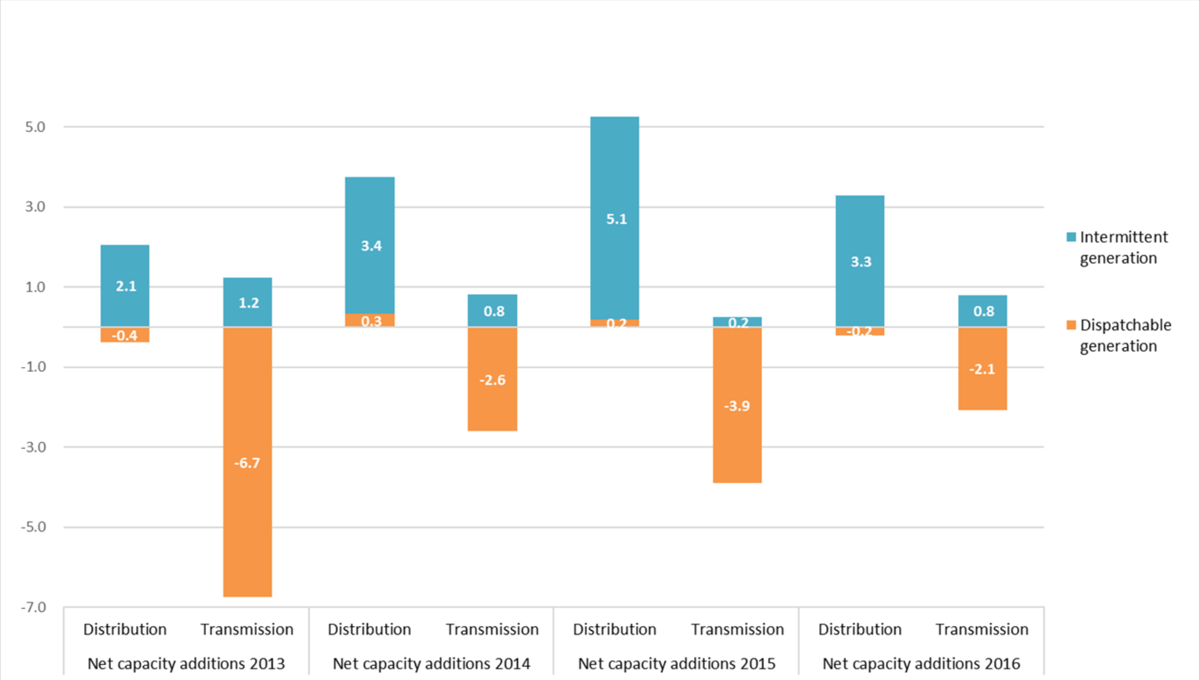
1.3. The energy system is undergoing a rapid transition. There is significant growth in intermittent and embedded generation[2] (EG), often concentrated in particular areas (such as solar in the south west of England and wind in Scotland). The potential future electrification of transport and heating may affect total usage and demand profiles across the lower voltages of the electricity distribution network. It means that areas of the network are either already or likely to become increasingly constrained, which could also have knock on implications at higher voltages.

1.4. This could lead to worse outcomes for consumers because:

- Existing network assets may not have enough capacity to accommodate new sources of demand on the system, such as electric vehicles or heat pumps, if they draw electricity at peak times. This could mean significant network reinforcement to accommodate these additional flows, which could increase costs to consumers substantially. For instance, findings from the Low Carbon London Project suggested that costs of network reinforcement as a result of uptake of electric vehicles could range between £6bn and £16bn by 2050.[3] Under the current access and charging arrangements these costs may not be sufficiently reflected in charges paid by those triggering them.

[2] Generation connected at distribution.
[3] The range represents the assumption that not all EVs will charge simultaneously and is drawn from the Low Carbon London project closedown report – available here: https://www.ofgem.gov.uk/sites/default/files/docs/2015/04/lcl_close_down_report_0.pdf

Figure 1: Dispatchable and intermittent net capacity additions across transmission & distribution networks (GW)



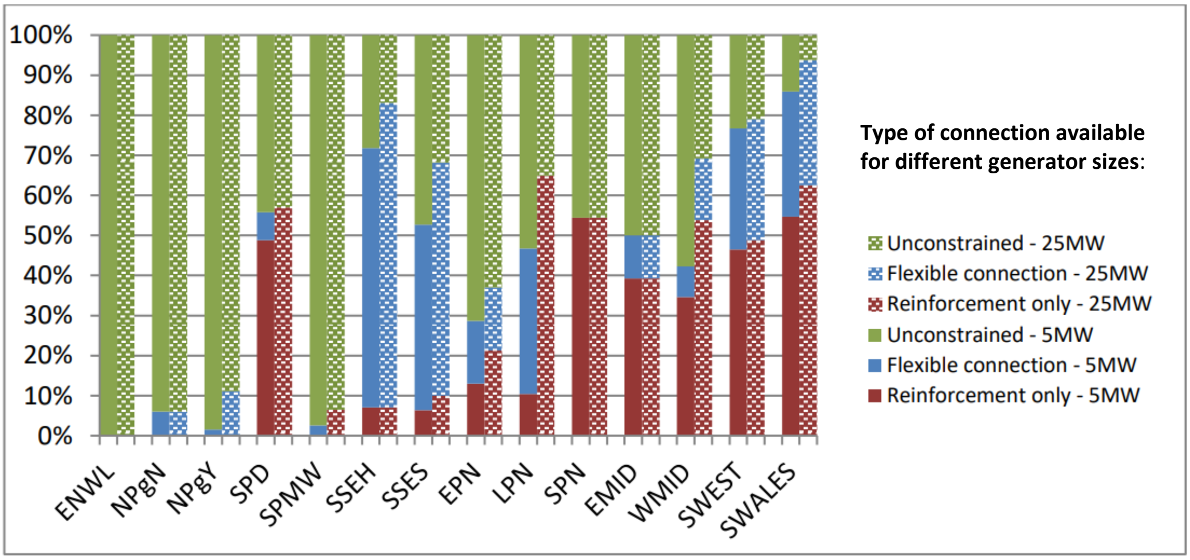
Source: DUKES data 2016

- Intermittent and distribution-connected generation has risen rapidly over the last few years, as shown in Figure 1, and is expected to carry on doing so. Network constraints could delay the connection of new sources of supply, including low carbon technologies. This risks delaying decarbonisation efforts and pushing up costs to consumers, if more cost-effective new sources of supply are unable to access networks on reasonable terms. It could also increase costs if network reinforcement is needed. Figure 2 shows how some parts of the distribution network are already constrained. This can lead to long queues and high costs of securing a connection to the network under traditional approaches. More efficient use of network capacity could help alleviate these constraints, particularly as the growth of intermittent generation means that there is increasing scope to share network capacity between users.

1.5. At the same time, the energy transition is providing major new sources of flexibility that could help alleviate constraints by managing the use of existing network capacity. These include electricity storage and consumers shifting their demand (demand-side response). This can reduce or remove the need for traditional network investment. For example, a storage facility locating near to intermittent generation could share existing network capacity and use the output of that generation to charge at times when otherwise the level of generation would have to be curtailed due to network constraints. A recent Imperial College study indicated that approximately £10bn to £13bn of network CAPEX investment could be saved by 2050 by exploiting flexible technologies.[4]

[4] The Imperial study can be accessed here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_analysis_of_electricity_flexibility_for_Great_Britain.pdf

Figure 2: Extent to which connection offers may be limited by network constraints[5] as reported by DNOs in May 2016



1.6. Tapping into these potential savings requires effective signals for users about how they can alter their behaviour to support more efficient use and development of the network. These could translate into lower consumer bills by reducing expenditure on network reinforcement. For example, effective signals should encourage individual network users to use the network in less constrained locations and reduce using the network during peak periods where they are able to do so. Half-hourly settlement (HHS) will provide the underlying market arrangements by which all network users can receive and respond to these signals where possible.

1.7. Technological changes are also increasing the potential for a wider consideration of how access to electricity networks is allocated between users and how it is charged for. Progress on technical enablers could range from automated and interconnected use of electricity appliances, to new business models like local energy and peer-to-peer trading which may make market approaches more feasible.[6] Intermittent generators could co-locate with storage to manage constraint risks or contract with aggregators to meet their contracted position.

1.8. We note that the future direction of the energy system evolution is inherently uncertain. The trends anticipated above may not materialise, and network usage may change in other ways. For example, it is possible that the increasing decentralisation of electricity generation leads to increased spare capacity on the network (particularly at transmission level). Any reforms should aim to be as resilient as possible to different outcomes.

Sending coherent signals across transmission and distribution

1.9. The current network access and charging arrangements were designed at a time when there was limited EG and electricity consistently flowed from the transmission network down to distribution networks. Consequently, there was relatively little

[5] For more details refer to our report on "Unlocking the capacity of the electricity networks", available here: https://www.ofgem.gov.uk/system/files/docs/2017/02/unlocking-the-capacity-of-the-electricity-networks-associated-document.pdf

[6] Relevant technological capabilities and developments include "Blockchain", "Peer to peer", "Big Data" and the "Internet of Things"

focus on ensuring generators receives consistent signals whether connected at transmission or distribution level.

1.10. This picture has now changed dramatically: the amount of generation capacity connected at distribution has doubled over the last five years and now represents over a quarter of total GB capacity.[7]

1.11. There are a number of inconsistencies in the current access and charging arrangements which become apparent when considering holistically the differing approaches taken at transmission and distribution. With increasing substitutability and competition between generators at different voltage levels, there is a risk that some of these differences could lead to distortions in investment and operational decisions driven by inconsistent access and charging regimes. This could potentially increase costs for consumers overall.

Our project

1.12. The scope of our electricity network access project is necessarily broad at this stage. We want to examine the links between the building blocks of a network access regime and network charges, across different types of network user. These interdependencies are important. For example, the nature of a network access right or 'product' (for example its geographical extent) could influence the choice of how to provide effective signals about incremental network costs through access or use of system charges.

1.13. The two main objectives of the project are to consider:

- the nature of network access rights and whether different ways of constructing and allocating them could have value.
- the appropriate forward-looking charges to access and use networks[8]. This covers what changes might be merited both with and without changes to the nature and allocation of network access rights.

1.14. There are other ways to provide signals for network usage that we are not considering as part of this work:

- including network signals in the wholesale energy price either through splitting the single GB wholesale electricity market into different market zones[9] or having fully locational marginal pricing (LMP)[10]. This project will not undertake further work on these policy options because:

    1. LMP would be highly complex and has particularly unclear, unproven potential in its application at distribution level - yet this is a key area of the network where we think signals need to be better. It is also very difficult to see how LMP could be implemented in a way consistent with

[7] DUKES figures for December 2016, available here: https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes
[8] When network access rights are well defined, the charges and liabilities supported by the network users should be directly related to the costs incurred in providing access and allowing use of the network.
[9] Market splitting is where a wholesale energy market is split into smaller zones to reflect structural network congestion.
[10] In an LMP market there is not a single wholesale energy price, but, potentially, many different nodal prices. These are established by using an algorithm which takes into account losses and network constraints.

our current self-dispatch model[11]. It would also involve major change to industry arrangements and existing contracts.

2. Market splitting is provided for under the EU Target Model, and there is a requirement to report periodically on the efficiency of existing bidding zones.[12] Following this a review can be launched to consider whether the existing bidding zones should be split or merged. The next potential review of bidding zones is in 2018. However, in our view market splitting is unlikely to be an appropriate model for managing distribution level constraints.[13]

- procurement by the transmission and distribution system operators (SOs). We discuss this further below.

1.15. We are not considering changes to access or charging arrangements for electricity interconnectors. These rules are well-defined under the European Capacity Allocation and Congestion Management code, and European rules also govern how network charging should be applied to interconnectors.

Past reviews

1.16. Over the last decade, there have been several reviews of transmission access rights, notably the 2008 Transmission Access Review (TAR). TAR was focussed on enabling transmission network access in order to meet renewable energy and emission reduction targets and in particular accelerating connections in the face of a growing transmission queue. TAR considered a range of options including market-based mechanisms for allocation of access rights, such as auctions and secondary trading, alongside variants on the Connect and Manage (C&M) regime[14].

1.17. At the end of TAR, the Government concluded that C&M would best achieve the aim of accelerating low carbon connections while providing investors with certainty. In response to Ofgem's annual report of December 2015 on the impacts of C&M, the Government highlighted potential concerns over anticipated and uncertain constraints costs and connection times. It asked us to look into actions within the C&M Framework which might bring forward improvements. It also signalled it would like C&M to move from a scheme imposed by government to one that is managed through the usual industry code governance process, and that it would be open to removing the Public Service Obligation (PSO) if we or industry felt this was

[11] LMP achieves its efficiency by clearing the majority of the market at the day ahead stage, so that the full range of dispatchable participants are available to the market clearer. To implement LMP it appears necessary to create a central pool. In LMP, the market clearer provides the dispatch schedule, and parties are only responsible for deviations to that agreed schedule. Our current market model involves self-dispatch, with gate closure an hour before real time.

[12] A bidding zone is defined as the largest geographical area within which market participants are able to exchange energy without capacity allocation. The process for splitting the market is outlined within Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (the CACM regulation). The European Target Model refers to the design of the EU electricity wholesale market established in the Framework Guideline on Capacity Allocation and Congestion Management for Electricity (CACM FG). The CACM FG, published by the Agency for the Cooperation of Energy Regulators (ACER) in July 2011, was part of the development of EU network codes mandated by a suite of EU legislation in 2009 for the European gas and electricity market (the Third Package) to promote the completion and efficient functioning of the single European energy market.

[13] To reflect distribution constraints through market splitting appears highly complex and problematic. To divide the wholesale market in a way that reflects all structural distributional constraints would, in effect, imply a move to quasi-nodal approach. All of the points about the issues with the application of LMP noted above then apply. In addition, there would other be other significant issues like the coordination of the TSO and DNO networks and the complexity of the optimisation problem for the market coupling algorithm to solve.

[14] Offering generation customers connection dates ahead of the completion of any wider transmission system reinforcements required under the security standards while the SO dynamically manages resulting constraints.

merited. Removal of the PSO may be necessary in order to make significant changes to the C&M regime.

1.18. With regards to network charging, Project TransmiT made changes to transmission charges to reflect the growth of intermittent renewables at transmission level. However, there is a growing recognition that further change may be needed in both transmission and distribution charging given further issues that have been emerging. National Grid began a transmission charging review in 2016 and, with stakeholder input, identified a range of network charging issues that stakeholders thought needed to be reviewed or revised.[15] The Energy Networks Association (ENA) has conducted reviews of both[16] the Common Distribution Charging Methodology (CDCM) and Extra high voltage Distribution Charging Methodology (EDCM) and recently considered elements of charging as part of its Open Networks Project.[17] Developing the ideas in this paper will build on those reviews.

The important links in this project with our other work

1.19. As we explained in our recent Strategy for regulating the future energy system[18], this work is part of a wider suite of projects looking at how arrangements may need to change to support an efficient, decarbonised future system. The strategy also explained how we believe that the development of the regulatory framework should be guided by the principles in our regulatory stances, and in particular:

- aligning the system operators' and network companies' interests with those of consumers, through clear obligations and well-designed incentives.
- ensuring that charging for monopoly services reflects incremental costs and benefits and recovers other revenue requirements in ways that are fair and reduce distortions.
- ensuring that regulation is neutral between different technologies, systems and business models, while encouraging new entry and innovation by, for example, promoting a level playing field between entrants and existing companies, and between network reinforcement and alternative solutions.
- providing a predictable regulatory regime which supports efficient investment and allocates risks efficiently.
- promoting competition and harnessing market based mechanisms where it is in consumers' interests to do so.

1.20. These principles will guide our work on access and forward-looking charges, as well as on our other work that this project is linked to:

- our **Targeted Charging Review (TCR)**, which is developing options through a Significant Code Review to improve how the "residual" elements of network charges are recovered. The residual element is the difference between the revenues recovered by the forward-looking charges and the network

[15] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/charging_review/
[16] http://www.energynetworks.org/electricity/regulation/distribution-charging/distribution-charging-working-groups.html
[17] http://www.energynetworks.org/electricity/futures/open-networks-project/open-networks-project-workstream-products.html
[18] https://www.ofgem.gov.uk/publications-and-updates/our-strategy-regulating-future-energy-system

companies' allowed revenues under their price control settlement. One consequence of the options we are considering in this project could be to alter the amount of revenues recovered through the forward-looking element of network charges and the relative amounts between the forward looking and residual charges. We will take account of potential future variability of the overall level of residual charges in assessing options for setting future residual charges under the TCR.[19] We have published a working paper on the TCR alongside this one.

- our work on the **role of the system operators**, both at the transmission level and that of Distribution Network Operators (DNOs) as they increasingly take on Distribution System Operator (DSO) roles in the short- to medium-term. This work is looking to ensure whole system coordination and encourage improvements in how the system operators procure flexibility services - both in allowing new types of provider to participate and in coordinating across transmission and distribution.

  Under one approach, network management could rely solely on the system operators' procurement of flexibility services as a means to mitigate network constraints. Providing signals through access and charging arrangements could offer the opportunity to allow the market to determine the best use of network capacity without having to rely on the system operators as central buyers. This could benefit consumers as a whole by providing better value and helping to ensure that investment occurs where needed, underpinned by a good understanding of market value.

  Access and forward-looking charging reform could reduce the amount that the system operators need to procure, but there is always likely to be need for them to take some residual actions. It is important that reforms in both access and forward-looking charges consider compatibility with procurement by the system operators, and that progress on the evolving DSO roles and coordinated procurement continues, through fora such as the ENA Open Networks project.

- Other work stemming from our **Plan for a Smart, flexible energy system** (which is joint with government)[20], such as work to remove barriers to the use of storage and aggregators. This project is aiming to support the efficient use of new sources of flexibility (such as storage, aggregators and demand-side response) by improving the signals they receive about the value that they can provide to the network.

- Our work on **future incentives and next round of price controls** (Future SO[21] and RIIO-2[22]). Work across a number of areas is considering the future regulatory arrangements for network companies and design of the incentive framework to ensure that the companies' actions are aligned with the interests of consumers. Any reform around access arrangements will rely on the SO and DSOs having the right incentives to make access available in an

[19] We note that the principles that we are using for the TCR differ from the desirable features we set out in this report. This is because our normal guiding principle for charging – cost-reflectivity – does not apply for residual charges and so there is a need to think about additional factors instead.
[20] Our Smart systems and flexibility plan, joint with government, is available here: https://www.ofgem.gov.uk/publications-and-updates/upgrading-our-energy-system-smart-systems-and-flexibility-plan
[21] Further information can be found in our recent working paper, here: https://www.ofgem.gov.uk/system/files/docs/2017/07/future_so_reg_framework_july_2017_working_paper.pdf
[22] Further information on RIIO-2 is available here: https://www.ofgem.gov.uk/network-regulation-riio-model/riio-2-price-control

efficient manner for the system as a whole, and minimise constraint costs through achieving the right balance of network investment and operational solutions.

Options for access reform could lead to better information on the need for network investment, which will inform the ongoing system planning of the network companies (both in terms of volumes and types of solutions) and could need to be reflected in the RIIO-2 business planning processes. Any changes to the depth of connection charges could also alter the amount of costs to be recovered through the price control.

Whatever the approach, it will be important that the future regulatory framework ensures network and system operators have an appropriate focus on optimising the availability and use of capacity in managing their systems efficiently.

- The roll-out of **smart meters and introduction of HHS[23]**. This will allow for more granular arrangements for network access and charging arrangements for households and small-businesses. The options we set out in this paper for these users would be reliant on this capability.

1.21. We will also consider links to current and planned changes to policy arrangements led by other parties, for example:

- the Government's policy around the roll-out of low emissions vehicles (amongst them electric vehicles), and decarbonisation of heat, and its response to the Helm Review on the cost of energy
- European policy developments, including the EU's Clean Energy Package and Brexit
- industry-led reviews, for example of network planning standards.

[23] Further details on the launch of the electricity Settlement Reform Significant Code Review can be found here: https://www.ofgem.gov.uk/publications-and-updates/electricity-settlement-reform-significant-code-review-launch-statement-revised-timetable-and-request-applications-membership-target-operating-model-design-working-group

2. Characteristics of network access and forward-looking charges

Desirable features of arrangements

2.1. In considering the need for and shape of any reforms, it is important to start from an understanding of consumers' interests in this context. Our considerations of this are framed by our statutory duties and our corporate strategy[24], which sets out how we aim to deliver five core benefits for consumers:

- lower bills
- reduced environmental damage
- improved reliability and safety
- better quality of service
- wider benefits for society as a whole, including support for those struggling to pay their bills.

2.2. An important starting point in the context of network access and forward-looking charging is to recognise that the electricity network exists to **meet the needs of consumers, as appropriate for an essential service**. The aim is for the network to meet the needs of users and the expectations of wider society as efficiently as possible.

2.3. Within this context, we see the following as being additional desirable features (developed considering our regulatory stances and principles for regulating the future energy system as set out in chapter 1) of network access and forward-looking charging arrangements:

- **Network capacity is allocated in accordance with users' needs**. Often, this will mean it 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 means that there will be constraints on the extent to which such market-based mechanisms will be appropriate. We discuss this further below.

- 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. Again, there may be some limits on the extent to which cost-reflectivity is appropriate, discussed further below.

- Arrangements support competition by providing a **level playing field** across different types of users, technologies or asset types (eg between network reinforcement and alternative solutions), avoiding undue distortions.

- Signals are sufficiently **simple, transparent and predictable** that they enable users to make decisions based on them. This includes supporting efficient investment in new energy resources, including low carbon technologies. In relation to simplicity, the underlying arrangements may involve complexity in order to provide robust signals, but additional

[24] See https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/corporate_strategy_0.pdf

complexity should have clear value, and consideration needs to be given as to how this will be manageable for relevant end users.

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

- Arrangements support **timely and efficient network investment** to meet users' needs, by providing high quality information as to 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, to the extent that they offer better value.

2.4. We note that there are likely to be trade-offs to be made in designing arrangements to meet these features. As noted above, there is a particular need to consider how network capacity is allocated and how cost-reflective charges are against the needs of consumers for an essential service.

2.5. For households, electricity provides for lighting, heat, cooking and other basic needs. This means that options that have significant distributional effects between consumers that cannot be justified by a reduction in overall costs (or achieving other objectives) are unlikely to be acceptable. This should frame consideration of options for households. For example, options that could see some denied network access to service their basic needs will not be acceptable.

2.6. At the same time, it is important to consider that new sources of electricity demand from some users could create significant network constraints, and yet those users may have more flexibility in responding to different access or charging signals. For example, an electric vehicle owner could choose to charge it at off-peak times, via a trickle charge rather than a rapid charge, or at a public charging point rather than at home at certain times. A consumer considering a heat pump should take account of network charges when deciding which low carbon heating options will be more cost-effective. If they did choose the heat pump then they could heat their house ahead of peak periods as, providing their house is energy efficient, the heat can be retained over the peak period.

2.7. Consumers also have a strong interest in the affordability of their supplies. This means there is substantial value to be gained from ensuring network costs are minimised through pursuing the desirable features listed. For households specifically, this means there may be a need to distinguish between the approach for access and forward-looking charging to allow consumers to service their basic needs from that for additional demand beyond that. We discuss this further in chapter 4.

2.8. We think these features provide a good basis to assess the effectiveness of the current arrangements. We also intend to use these desirable features to guide our assessment of the merits of options for change, as well as considering our wider objectives and statutory duties.

Building blocks for network access and charging arrangements

2.9. In considering options for network access and forward-looking charging reform, it is useful to consider the key design parameters, or building blocks, that could make up the arrangements. This section describes these and sets out some high level considerations of the different possible choices. The building blocks outline the key different possible choices for how network access rights and forward-looking network charges could theoretically be constructed. These could apply differently to different types of users, although consideration would need to be given as to how different approaches combine to create a coherent overall framework.

2.10. The key 'building blocks' can be categorised at a high level as follows:

<table>
<tr><th colspan="2">Network access arrangements</th><th colspan="2">Forward-looking charges</th></tr>
<tr><td rowspan="5">Nature of access rights</td><td rowspan="2">Time aspects</td><td rowspan="4">Structure of charge</td><td>Types of costs</td></tr>
<tr><td>Types of charge</td></tr>
<tr><td>Firmness</td><td>Basis of charge</td></tr>
<tr><td>Geographical nature</td><td>Timing of payment and degree of user commitment</td></tr>
<tr><td>Associated conditions</td><td rowspan="3">Level of granularity</td><td>Locational granularity</td></tr>
<tr><td rowspan="2">Allocation and reallocation</td><td>Initial allocation</td><td>Types of locational signal</td></tr>
<tr><td>Reallocation and trading</td><td>Temporal granularity</td></tr>
</table>

Access building blocks

2.11. In thinking about network access, we are considering what network capacity a user has had allocated to them by a system operator in order to be able to either import or export electricity from their target market. At a fundamental level, access can be seen as requiring two distinct things: a connection from a user's location to the wider network (ie the infrastructure that will be for their sole use), and then allocated capacity on the wider network. The options we are setting out in this paper are focused around this second element, ie whether there is scope to improve how the arrangements address access to the wider network.

2.12. There are a range of different design parameters relating to how these access rights could be constructed.

2.13. **Time aspects**: Access rights may be offered for different durations, long or short-term, to match users' requirements. Charges and securities may need to vary depending on the duration. Equally, rights to use the system may be split according to different time periods they apply to (eg for the different seasons or off-peak vs peak periods), which may enable network capacity to be used more fully by more dynamic or flexible users.

2.14. **Firmness:** Users' access to the wider network can vary in the nature and level of firmness.

2.15. Networks are designed and operated to achieve a certain level of physical firmness, which can be seen as how secure a user's connection is under certain network conditions. At minimum, physical firmness will be seen as being able to achieve access when there are no circuit outages. For some user types, it would also include some redundancy such that they can still enjoy access if there is an outage (this is known as N-1 conditions). These security levels are generally informed by network technical standards and reliability incentives, although users can request different levels of physical firmness.

2.16. Financially firm rights provide for users' access to be curtailed with agreed compensation, while under non-firm arrangements, users can be curtailed without compensation. Access may be curtailed according to pre-defined rules ('last in first off' or 'pro rata'), or at an agreed price which users may offer through a market mechanism. Variants could include agreements with different levels of curtailment or firmness, and hybrid approaches may be possible, with some firm and some non-firm capacity. Non-firm arrangements could also be used for time-limited, interim periods – for example, pending completion of wider upgrades.

2.17. **Geographical nature:** Access rights may be defined to apply to the whole system (ie allow access to the whole market), within a given area (such as behind a particular network constraint), voltage level or across a specific piece of network infrastructure (as with an interconnector). The granularity with which they are defined may vary by different voltage levels or for user types, to match their needs and capabilities, or using a more standardised approach. If rights are defined with greater locational granularity, this could potentially enable access products to a particular local area to be made available, even where capacity further upstream was fully utilised.

2.18. **Conditions of rights**: 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. This could include a requirement to release unused capacity to other network users, as is the case in other sectors[25], or other requirements such as payment of certain charges.

2.19. **Initial allocation:** Capacity can be allocated on a 'first-come-first-served' basis. Alternatively, approaches could offer capacity to the market in periodic windows – either through an auction or other mechanism – enabling parties to signal their interest in obtaining access with their relative value to determine allocation of limited capacity. Closer to real time, additional capacity could be made available as real time conditions allowed, through offering short term capacity to the wider market or lowering curtailment levels for non-firm arrangements.

2.20. **Reallocation and trading:** The way rights and products are defined can enable longer-term access, as well as shorter-term capacity or the ability to vary or curtail capacity to be traded or reallocated between network users. This may involve the system operators as an intermediary, or it could be done more independently.

Forward-looking charging building blocks

2.21. **Types of charge:** Different network activities create separate costs that can be charged individually. Theoretically these could be separated into three categories: (i) 'Connection' charges – which recover the costs of enabling users to connect to the network (ii) 'Access' charges – which reflect the costs and/or value of providing users with network access, and (iii) 'Usage' charges – which signal, cost reflectively, the actual costs (or benefits) imposed by network users' actual usage. In practice, these charges can be combined in some forms. However, access and usage charges can be seen as substitutes for each other – access charges place an emphasis on the access right that a user holds as a basis for charging, whereas usage charging may be used where there is less emphasis or clarity on access rights. An analogy is considering charging for mobile phones - pay monthly for a pre-defined calls/data allowance (an access charge) compared with pay as you go arrangements (usage charging).

[25] Examples include 'Use it (capacity) or lose it' or 'Use it or sell it' conditions apply currently for cross border electricity transmission capacity and in gas transmission, as well as being widely used in other sectors, such as rail. They help prevent capacity hoarding and ensure it is used efficiently

2.22. **Types of costs**: Different types of expenditure are incurred when providing access (eg capital expenditure, maintenance expenditure and operational expenditure). This includes the costs of managing network constraints. It could also include the cost of losses. Where a cost is affected by a change in users' behaviour, then the forward-looking charge will need to be able to target that behaviour. The other building blocks discussed in this section may vary according to the type of costs incurred.

2.23. **Basis of charge:** There are different bases upon which charges can be made. First of all, charges can be levied on a gross (ie taking a user's electricity imports or exports separately) or net basis (ie net imports or exports)[26]. In general, a net basis is likely to be appropriate for forward-looking charges as this represents the overall impact of the user on incremental network costs. Furthermore, there are the options of volumetric charges (based on the amount of energy imported/exported onto the network (£/kWh)), capacity charges (based on the maximum power exported/imported onto the network (£/kW)), reactive power charges (eg through a direct £/kVAr or £/kVArh charge, or by charging for apparent power capacity (£/kVA) or fixed charges (that do not vary). These can also be combined. An additional choice with a capacity charge is whether it is based on a pre-defined allowed capacity (ie an access charge as described above) or on actual maximum capacity (ie a usage charge). Charges may also be set either ex-ante or ex-post.

2.24. **Timing of payment and degree of user commitment:** Costs can be recovered from customers at different times. Charges can be required from users upfront or can be levied on users on an ongoing basis. If costs are recovered over time then the customer may need to make some commitment to their future payments (eg by providing security to cover any outstanding costs that it is directly liable for).

2.25. **Locational granularity:** The cost of obtaining access to the network varies geographically or at different voltages. Locational granularity is the extent to which charges partition geography into separate 'locations'. Charges could be nodal (ie different for every network substation), zonal (different charges for different geographic regions) or common for all consumers.

2.26. **Types of locational model:** Charges can be used to signal the *absolute* costs of the impact which users in particular locations have on network costs, or the *relative* costs of network access or usage compared to users in other locations. Relative charges may lead to users in some locations getting a payment if they are offsetting the costs imposed by other users, whereas those in other areas may get a charge. The way charges are determined and the extent to which interactions between users are considered in the model may affect the type of signals a charge provides as well as the level of granularity. For example, charging methodologies may take account of operational conditions, network planning standards, network power flows and spare capacity on the network. All of these issues can affect how charges are determined.

2.27. **Temporal granularity**: Charges can be varied over different time periods to reflect how the cost of network access or usage varies. Different levels of temporal granularity (eg half-hourly, seasonal, yearly) are appropriate for sending different cost signals. Different granularity may be appropriate for different types of costs.

[26] In this paper, electricity usage is referred to either as either user's import or network exit, while electricity production is referred to as a user's export or network entry.

3. The current access and charging arrangements

3.1. This chapter outlines how the current access and forward-looking charging arrangements work against the framework set out in the last chapter. First, we describe how the current arrangements work against the building blocks. We then set out what we see as some key potential issues of concern and shortcomings against the desirable features of network access and forward-looking charging arrangements.

Overview of access arrangements

3.1. Please note that this chapter only provides a simplified and high level description of the legal and regulatory framework applicable to network access and network charging. This chapter is meant to serve as a starting point for discussion and work with industry representatives and stakeholders on the options available, reflecting our understanding of where potential concerns may lie. It should not be read as an exact description of the complex arrangements in place, nor does it present an exhaustive description. Rather we present some features here which illustrate a range of different aspects of the arrangements that have relevance for the potential issues being considered by this project.

Nature of access rights

3.2. As discussed in chapter 2, access can be seen as requiring two distinct things: a connection from a user's location to the wider network, and then allocated capacity on the wider network. It is the latter element that is the focus of the options considered in this paper.

3.3. Significant differences exist across transmission and distribution, generation and demand. On the transmission system, the access to the wider network that generators need is considered quite explicitly in their 'transmission entry capacity' (TEC). For many other network users there has typically been less explicit consideration of their 'access rights' to the wider network.

Access to the transmission network

3.4. The SO is required to offer terms for connection to parties seeking new connections to the transmission network. Both transmission-connected demand and generation users, as well as DNOs and certain categories of EG need to sign a Bilateral Agreement with the SO to connect to the system.[27] For transmission-connected generators (TG), the Bilateral Connection Agreement (BCA) specifies their Connection Entry Capacity. Demand customers, including DNOs, must declare a MVA value for their grid supply point in their application.

3.5. Additionally, generators also need to have an agreed TEC. This typically allows them 'financially firm' access to the system: they are able to export electricity on to the system up to their level of TEC, subject to payment of relevant charges in a

[27]The process and requirements may differ depending on the type of user – for instance, a generator's size and whether they connect at distribution or directly to the transmission network. EG may be required or may choose to apply for 'explicit' transmission capacity through a 'Bilateral Embedded Generator Agreement' (BEGA). Other users may enter a Bilateral Embedded Licence-exemptible Large power station Agreement (BELLA). The DNO will have an agreement with the TSO for any construction works which sits alongside this agreement. Demand users directly connected to the transmission network and suppliers have requirements to submit forecast import levels.

given year, and provisions set out in codes and other provisions.[28] Users may be eligible to receive payment – typically either for BSC parties in the balancing mechanism if relevant transmission capacity is not available and they are called on to adjust their output, or directly in relation to relevant interruptions. A limited range of shorter term (within year) TEC options is currently available, though these are not widely used.

3.6. Generators must indicate their required capacity alongside their connection application, but may physically connect to the network in advance of obtaining TEC.

3.7. Demand users do not have an equivalent to TEC. They must submit accurate forecasts of their required power (for end customers this is typically facilitated through suppliers on their behalf), which they expect to have use of, subject to provisions in codes and elsewhere.

3.8. Where users have TEC, that capacity is not defined more locationally than by reference to the transmission system as a whole, though the user's connection point to that system is considered and may be relevant for any exchanges.

Access to the distribution network

3.9. At distribution, parties are able to request a connection to meet requirements for electricity under reasonable terms under the Electricity Act 1989. DNOs are required to offer terms for connection.[29]

3.10. DNOs have a duty to connect a customer, and maintain that connection. Currently, applicants for a new or amended connection specify their capacity requirements in their connection application. A user's connection is subject to the provisions of the DCUSA, including the National Terms of Connection, among other relevant provisions.[30]

3.11. There is currently no additional step to obtain distribution system 'access' as distinct from the capacity agreed as part of the connection agreement. For households and small businesses in particular, the connection may have been agreed with the developer prior to occupancy. During RIIO-ED1, in principle existing households are able to increase their usage up to a limit of 100 amps[31] (approximately 23 kW, single phase) without being liable for any reinforcements costs this could trigger. However, DNOs do not plan the network on the basis that households will access this amount of capacity continuously and it is substantially above current average household consumption. For example, one DNO's charging statement suggests they typically design connections to new build homes that aren't electrically heated to a capacity of 15 kW (though there is scope to agree a different amount). Many users' requirements do not approach even this limit for significant periods (though a combination of typical uses may mean that they approach it

[28] Among others, the Connection and Use of System Code (CUSC) and the Grid Code. Users may agree a design variation which may have availability restrictions associated with the fact that their connection deviates from SQSS specification.
[29] In this document we do not describe how arrangements may differ for 'Independent DNOS' (IDNOs) though this would need due consideration.
[30] These may include, among other provisions, other industry codes, standards of performance and connection charging regulations.
[31] The typical fuse size in a household's meter. This acts to protect the network if there is a fault in the property. We decided in our RIIO-ED1 decision that until DNOs have a means to accurately identify the customers who trigger cost, they will continue to recover the costs of any reinforcement caused by load or generation growth by domestic and small business customers through DUoS charges, further information here: https://www.ofgem.gov.uk/sites/default/files/docs/2013/02/riioed1decoutputsincentives_0.pdf

transiently), so DNOs assume a lower level of average demand in planning the wider network to reflect the diversity of demand patterns.[32]

3.12. There is scope for connection agreements include different terms. Some 'flexible connection' agreements allow for curtailment, for instance where constraints would mean network upgrades might otherwise be needed. These have served to reduce the time, and cost, to access the network when congested.[33] Curtailment principles are typically set ex ante, though actual levels of curtailment will be variable based on actual network conditions and location.[34] There has been limited standardisation of terms across different DNO schemes.[35]

3.13. Additionally, small users with on-site generation may not be visible to network operators and have different connection arrangements.

Allocation mechanism

3.14. *Initial allocation* - Capacity is allocated 'first-come-first-served' across transmission and distribution, though in practice, the connection time may depend on the timing and cost of required works. The amount of capacity which is available to be allocated is determined considering network planning standards. There are currently queues[36] to connect to parts of the transmission and distribution networks (although this varies by location and between demand and generation). However, this process does not account for how parties in this queue may value use of the network differently relative to others in the area.

3.15. C&M, introduced in 2011, enables earlier, financially firm connections to obtain transmission system capacity under a derogation from some aspects of the Security and Quality of Supply Standard (SQSS). This means generators may connect ahead of wider reinforcement being completed with resulting congestion managed operationally.

3.16. *Reallocation and trading* – There are different approaches to reallocating capacity across the system.

3.17. At present there is limited scope to exchange TEC, and little use has been made of provisions to do so.[37]

3.18. On operational timescales, transmission system constraints are typically managed as paid actions in the balancing mechanism (though some non-firm options are available). Users who are BSC parties submit bids into the Balancing Mechanism to indicate their respective costs for adjusting their usage. Constraint payments are

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[32] This reflects the diversity of consumers, discussed further in a report from the Customer Led Network Revolution LCNF project, which considers a range of around 1.5-2kW, available here: http://www.networkrevolution.co.uk/project-library/diversity-maximum-demand-admd-report/
[33] These include flexible options which some network owners have developed to allow distribution users to connect ahead of reinforcement.
[34] Curtailment estimates provided earlier in the connections process can enable prospective connectees to assess the likely level of curtailment when making their investment decision to accept a connection offer. However, the DNO does not typically provide a commitment to levels of curtailment, which may change over time, for instance as background demand levels or microgeneration in an area changes.
[35] The ENA Open Networks Project is considering where potential exists to standardise terms further. Further detail on the project is available here: http://www.energynetworks.org/electricity/futures/overview.html
[36] Where more than one unsigned connection offer relates to a given supply point, National Grid creates an interactive queue. In parts of the network, this can be long if users are awaiting reinforcement. Where interactivity occurs the relevant network and system operators will identify and manage the relevant queue.
[37] Temporary TEC exchanges are provided for under the CUSC in some circumstances. Users must request an exchange rate to transfer TEC between parties.

recovered from a broad subset of network users. While these costs can provide a good signal against which to assess the merits of new network investment, they are not fully market based, and so justification for new transmission capacity relies on the system operator and network owners' forecasts and processes (such as the Network Options Assessment and Strategic Wider Works).[38]

3.19. At distribution level, those connected under flexible arrangements can be curtailed according to rules typically established up front - either 'last in first off' (equivalent to first-come-first-served), or 'pro-rata'.[39]

3.20. Again, these arrangements typically do not consider parties' opportunity cost of curtailment in operational timescales. Under these flexible approaches, network operators typically bear limited costs, with the connecting party shouldering sometimes unclear curtailment risks without compensation.[40] This provides limited value signal about where new investment is justified – to network operators or potential market providers – and may undermine the investment case for flexible solutions. Connecting customers are strongly reliant on network operators' planning and processes to bring forward new capacity efficiently, given substantial challenge of coordinating between users directly.[41]

3.21. The approaches taken to manage congestion differ across the system. Transmission system capacity is typically treated as financially firm, with congestion costs socialised. At distribution, individual users may choose to bear the operational costs of curtailment, rather than contribute to network upgrades when distribution capacity is limited.

Overview of charging arrangements

Types of costs

3.22. The treatment of different costs varies across charging methodologies. In general, it is closely linked to the RIIO price controls, with charges set to enable network companies to recover their allowed revenues. Forward-looking charges aim to reflect and signal the incremental costs associated with access to and usage of the networks, and residual charges are then used to ensure revenue recovery.

3.23. Transmission Use of System (TNUoS) and Distribution Use of System (DUoS) charges are based on the costs associated with investing in new network assets, ie the long run marginal cost (LRMC). This is generally based on the costs of conventional network design and operation, with some accounting for new technologies. TNUoS cost signals are determined based on the relative costs (per km per MW) of different types of cable and overhead line. The EDCM cost-reflective charges similarly consider the Modern Equivalent Asset Value (MEAV) of the existing network when calculating forward-looking charges, but also allocate direct and indirect operating costs using forward looking principles.[42] Neither method accounts for non-build solutions (eg constraining generators). There is also limited treatment of new network technologies such as costs associated with smart grids and active

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[39] 'Unlocking the Capacity of the Electricity Networks' – published earlier this year, gives an overview of the status of constraints on the transmission and distribution networks, and the approaches network operators are taking to release capacity when the network is constrained, including C&M and flexible connections. The document is available here: https://www.ofgem.gov.uk/publications-and-updates/unlocking-capacity-electricity-networks-overview
[40] Though in opting for a flexible connection, network users will have saved on the capital cost through avoiding triggering network reinforcement.
[41] Incremental changes such as evolved consortium registers can help increase visibility for users.
[42] This is done using Network Use Factors (NUFS) which are calculated based on a power flow model.

network management (although the TNUoS methodology does account for costs associated with high voltage direct current links).

3.24. On the other hand, Balancing Services Use of System (BSUoS) recovers the cost associated with the SO operating the existing transmission system, ie the short run marginal cost (SRMC), including costs for constraints, procurement of system balancing services and operations costs. There is no equivalent SRMC based charge for the distribution network. Historically, the majority of distribution network cost has been incurred in the long-run, so that the SRMC of the network is low. This may change in the future, as DNOs transition to DSOs.

Types of charge

3.25. We generally just distinguish between use of system and connection charges:

- **Connections Charges**: these recover the incremental cost of providing a user with a new or increased connection to the network. Their coverage is different depending on whether a user is connecting to the transmission or distribution system. For transmission connections, the "connection boundary" is shallow, so connection charges recover the costs of sole-use assets needed to connect a user to the existing network.[43] For distribution connections, the connection boundary is referred to as "shallow-ish", in that connection charges can also recover a portion of the deeper reinforcement costs to the existing network needed to provide the user with firm access to the system.

- **Use of System Charges** (TNUoS and DUoS charges): allow network companies to recover their revenue allowance as set by our RIIO price control. The revenue allowance is the amount needed to operate and maintain their networks. Use of System Charges have two parts to them:

    - Forward-looking element – aims to reflect network users' incremental impact on network costs, including current and future investment and reinforcement (that is not recovered through connection charges).

    - Residual element – 'top up' charges are required to ensure that the network's efficient costs, as determined through price controls, are covered, after other charges have been levied. Our Targeted Charging Review is reviewing the approach used to calculate residual charges. They are outside the scope of this project.

3.26. In addition, BSUoS charges recover the SO's costs in operating the system (ie the SRMC). They are recovered on a socialised £/MWh basis from demand, TG and larger EG. A significant proportion of these costs relate to managing constraints on the transmission network, and so the treatment of these costs needs to be included in considerations about how to provide effective signals to users about their impact on the network. The remainder of the costs relate to energy balancing or other system services and so do not fall within the scope of this project. The TCR SCR is considering whether current BSUOS charges, or reduced BSUOS charges if constraint costs are removed, should be recovered in line with options being considered for the transmission and distribution residual charges.

[43] At transmission, connection charges do not recover the costs of all sole use assets if these assets are considered to be 'infrastructure assets' rather than 'connection assets'. Some costs, particularly for offshore assets, are instead recovered through use of system charges through the forward-looking element of charges (via the "local" element of TNUoS) and so are targeted back on the generators being connected in a similar way to connection charges.

3.27. The actual level of charges faced by different types of users varies. For example, for generation:

- Smaller EG in aggregate receive payments from DUoS charges, whereas TG and Larger EG make payments in aggregate towards TNUoS charges (including the local circuit element of TNUoS charges). Furthermore, smaller EG is treated differently within BSUoS than TG and Larger EG.

- EG pays connection charges which reflect some additional reinforcement costs on the network, whereas TG connection charges only cover connection assets. This is offset by the ability of smaller EG to avoid costs as they have a greater range of locational options, and by the credits they received from DUoS.

3.28. Simply distinguishing between connection and use of system charges blurs the concepts of 'connection', 'access' and 'usage' charges as shown in the table below. At transmission, generators' Use of System (UoS) charges are access charges as they are determined principally by a generator's access rights (ie TEC), rather than the generator's actual usage. Additionally, some costs recovered through TNUoS could be seen as connection charges as they recover the costs of sole-use assets connecting to the existing system.

3.29. At distribution level, connection charges can be seen as hybrid connection and access charges as they may involve a contribution to wider system reinforcement. DUoS charges contain a combination of access and usage charges. The CDCM includes capacity charges based on contracted capacities for some Half Hourly (HH) demand customers, and the EDCM includes capacity charges for all demand customers. Both of these only apply to a small sub-set of overall EG customers. For Non Half Hourly (NHH) customers within the CDCM, the fixed charges includes an element which is based on a deemed average capacity for each type of user, which we understand is typically 1-2 kWs. This could be seen as an access charge, but one for which the rights are not clearly defined.

3.30. At a high level, the following table highlights how the concepts of 'connection', 'access' and 'usage' map across to the current GB arrangements.

3.31. We are considering whether the current structure of charges continues to be fit for purpose as the system is changing. This includes considering whether charging structures could be simplified, or whether a new charge might be needed for new types of cost (discussed above), such as a DSO charge for recovering constraint costs, similar to BSUoS.

Concept	Current application in GB			
	Distribution		Transmission	
	Generation	Demand	Generation	Demand
Connection	The element of the connection charge that does not relate to reinforcement costs.		Connection charge Local TNUoS charges	Connection charge
Access	The element of the connection charge that relates to reinforcement costs.	CDCM capacity charge EDCM import capacity charge The element of the connection charge that relates to reinforcement costs.	TNUoS	
Usage	Other DUoS charges		BSUoS	TNUoS BSUoS

Basis of charge

3.32. Network connection charges are calculated based on work required to provide the maximum export or import capacity requested by the party. A customer may be able to negotiate to benefit from a reduced connection cost, if they are willing to vary their maximum import or export capacity over time (referred to as a flexible connection).

3.33. Across the system there are different methodologies used to calculate UoS charges. Each of these use a different cost basis.

3.34. At distribution, the Common Distribution Charging Methodology (CDCM) is used to recover UoS charges for users connected at the low voltage (voltage levels less than 1kV) and high voltage levels (voltage levels less than 22kV, but greater than 1kV). The CDCM uses a combination of volumetric charges, capacity charges, reactive power charges and fixed charges, which vary depending whether the user is half-hourly or non half-hourly settled. The Extra high voltage Distribution Charging Methodology (EDCM) is used to recover UoS from customers that are connected to DNOs' extra high voltage network (ie networks with a voltage level of 22kV or more). EDCM charges are based on a capacity charge, a volumetric charge and a fixed charge.

3.35. In general, volumetric charges do not closely reflect drivers of network investment, which largely depends on short term peak utilisation of assets. Therefore relying on these does not support effective cost-reflective pricing. This may become more of an issue as users become more flexible and patterns of usage become more dynamic. For example, the costs of network reinforcement triggered by electric vehicle (EV) owners choosing to rapidly charge their vehicles at peak times would be largely socialised across all users. There is scope to minimise these costs if users take into account network conditions when deciding how to charge (eg a slower charge or not charging during peak periods). The current basis of charging may not provide the appropriate signals for this if (eg it does not distinguish between different levels of peak demand for EV users).

3.36. At transmission level, demand TNUoS charges are based on the volume of electricity consumed during system peak demand within demand zones.[44] This means smaller EG are treated as negative demand which results in them facing the inverse of the TNUoS demand charges instead of facing TNUOS generation charges (faced by TG and larger EG). This is an issue we identified under our review of Embedded Benefits and said we would consider through this work.   For generation, wider TNUoS charges are capacity based and determined within generation zones. Local generation TNUoS charges also reflect the cost associated with the transmission substation they connect to and, where a generator is not connected to the main interconnected transmission system (MITS), the cost of local circuits that the generator uses to export onto the MITs. BSUoS charges are apportioned based on the amount of energy imported or exported onto the network (£/MWh) within a given half-hourly period.

Timing of payment and degree of user commitment

3.37. Electricity distribution connection charges need to be paid in advance of energisation of a user's supply.[45] Electricity transmission connection customers may pay for the cost of the connection assets over a 40-year period, though they carry the liability for these costs over that period.

3.38. Network companies also recover use of system charges (DUoS, TNUoS and BSUoS) from network users on an ongoing basis.

3.39. Before getting connected, transmission users are liable for the cost of local transmission works that can be directly attributed to the network user (or a group of network users) and they must provide security to cover this amount.[46] Once connected, network users' have limited ongoing liabilities for any outstanding connection charges and a proportion of wider transmission system investment costs if they reduce or cancel their agreed maximum capacity with sufficient, relatively short-term, notice.[47] This means that the risk that the investment triggered by a user may be underutilised is borne in part by network operators and consumers more generally.

3.40. A DNO may request a security deposit from any party that requests a connection, in relation to their connection expenses. In such circumstances the DNO sets out the amount and terms involved. Any change to the distribution connection charging boundary may prompt a review of the approach to requiring security at distribution.

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[44] For HH demand customers, this is based on the volume of electricity consumed during three 'triad' periods. For non-HH demand customers, this is based on the aggregate volume of electricity consumed during the period 4pm to 7pm across the whole year.

[45] A customer can agree with a DNO to make staged payments prior to energisation.

[46] The level of security required reduces as the project nears commissioning and passes set milestones (eg it achieves planning consent). Once a user connects to the network, it is not liable for these amounts and the costs of local transmission works is recovered via use of system charges.

[47] The liability for post-commissioning generation projects takes into account the investment for wider transmission works only. The total cost of liability is calculated in accordance with the Connection Use of System Code (CUSC). If the network user gives notice of at least two years or more (depending on when they disconnect) then it is not liable for wider transmission works.

Types of locational model

3.41. Across the system there are different methods used to calculate UoS charges. These send different types of relative or absolute cost signals to users.

3.42. In GB, both transmission and distribution connection charges are based on the absolute costs of providing connections to the system. These are set based on the costs which the network operator actually incurs for a particular user.

3.43. In contrast, TNUoS and DUoS charges provide *relative* signals of cost impacts rather than absolute cost signals, although we believe that signals may be closer to absolute in some of the methodologies than others (eg the local circuit tariffs within TNUoS and the EDCM charges are possibly closer to signals of absolute cost).

3.44. Relative charges guide users as to the impacts which their investment and operational decisions have on the network compared to other similar users. For example, the relative generation TNUoS charges achieve this while the transmission generation residual charges ensure that average transmission generation charges are kept within the €2.50 /MWh cap required under EC Regulation 838/2010.[48] However, as the distinctions between different types of user become less clear cut (eg with more competition between TG, EG, and flexible demand), we may need to consider whether these relative signals are still being preserved across different parts of the system, particularly as each methodology takes a different approach to determining these relative costs.

Locational granularity

3.45. 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.

3.46. The different UoS charging models have varying degrees of locational granularity. The CDCM does not include any locational granularity within a DNO area, and so does not give any signal to users about which locations on a DNO's lower voltage networks are better to locate. This applies to both demand and generation. This may be an issue in the future if new technologies, such as EVs, tend to cluster in certain parts of the network, as this could then lead to cross-subsidisation.

3.47. EDCM demand charges include a strong, locational element which is distinct for every substation in the network. However, this is unpredictable and can be quite volatile, making it difficult for users to respond to.

3.48. EDCM generation charges do not include a locational element (although they do include locational credits, depending on time of use). Generators automatically receive a credit within the CDCM, even if the specific area of the network the generator is in is generation-dominated, so that additional generation may increase rather than reduce network investment. The size of the credit depends on whether the generator is intermittent or non-intermittent.

3.49. All transmission connected users are levied a wider TNUoS tariff according to their 'zone'. Some TG also pay local tariffs. These local tariffs reflect the costs of the generator's local infrastructure. Concerns have been raised that TNUoS tariffs do not

[48] The €2.50 /MWh cap help to reduce distortions to flows across cross-border interconnectors. If TNUoS was to provide signals of *absolute* cost impacts, then this might not be compliant with the cap if generation users cause lots of cost.

handle the impact of EG well. This was explored through an informal consultation by National Grid in 2015.[49] Charges do not reflect where high levels of EG lead to transmission network costs due to exports from Grid Supply Points back on to the transmission network.

3.50. BSUoS charges do not include a locational element for constraint management costs. Some of these costs can be attributed to those generators benefiting from accelerated connections under the Connect and Manage (C&M) arrangements. The Government decided that these costs should be socialised at the time of C&M implementation but developments since then (including the divergent approach for accelerated connections at distribution-level and greater scope for generators to manage constraint risks now) suggest that there may be merit in reviewing this approach.

Temporal granularity

3.51. Connection charges are based on the cost of connecting to the network at a specific point in time, as calculated by the relevant licensee. Once the cost of the connection has been determined, it does not continue to vary over time.[50]

3.52. In relation to UoS charges, the charging methodologies (with the exception of charges for TG) include higher charges during certain time periods for some, but not all, network users. For example, EDCM charges includes a charge for the amount of electricity consumed (or produced) during the 'super-red' system peak. BSUoS charges vary a lot over time, with different charges levied for every half hour.

Summary of concerns

3.53. The key areas of concern we have identified with current arrangements, considering the above principles, are summarised at high level in the table below.

[49] "Informal Consultation on Potential Transmission Charging Arrangements at Exporting Grid Supply Points" available from http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Transmission-Charges-Open-Letters/
[50] Though in certain circumstances, subsequent users may make a contribution to the originally provided capacity

Desirable features of arrangements	Summary of potential concerns with current arrangements
Consumers' requirements are met efficiently, as appropriate for an essential service	Inadequacies in arrangements (discussed in other features) mean that requirements may not be met efficiently, with greater cost than necessary.
Optimising capacity allocation	Access is typically allocated first come first served, with users having limited choice in the types of access product to allow them to optimise how they secure access. Also there is limited scope for users to trade capacity, or only via system operator-led actions.
Signals reflect incremental costs and benefits	As cost drivers change, existing charging structures may not adequately reflect these, with different approaches to how costs are allocated across different charges. No locational element to CDCM or transmission constraints (BSUoS) cost recovery. EG do not receive accurate locational signals of the costs that they may cause.
Level playing field	Access arrangements and charges vary differ across the system – by voltage levels (eg transmission compared with distribution) and, to some extent, for users of different types or sizes. Some of these differences may be causing material distortions.
Effective signals for network users	Variability and lack of predictability in charges (especially BSUoS and EDCM) can make it difficult for users to build them into their decision-making.
Appropriate allocation of risk	Limited ongoing security requirements (principally at transmission level) means network operators and consumers bear some of the risk of investment triggered by specific users. At distribution, network users can bear risks of curtailment.
Arrangements support efficient network development	Arrangements generally provide poor information to inform decisions on future network investment. Congestion signals only provide a current value at transmission-level and are only quasi-market based, while 'spilled' energy is not valued at distribution. Strong reliance on network monopoly processes to coordinate bringing forward new capacity.

3.54. In the following chapters, we describe a range of potential approaches which could be considered in access and forward-looking charging arrangements, which could have the potential to help address some of these concerns. These are not discrete or fully developed options and have not been assessed for feasibility or desirability. It is unlikely that all issues would be addressed. We will need to consider the scale of change and costs of doing so as well as potential benefits and our wider statutory duties. Our proposed approach to taking this work forward is outlined in chapter 7.

4. Where could changes to network access arrangements create benefits?

4.1. We think a range of aspects of the existing arrangements for access have the potential to help effectively address the issues identified above, and support more efficient usage and development of the network.

4.2. In other sectors, there is often a much greater emphasis on access rights, and there may be learnings which we can draw on here. For example, in the telecommunications sector there has been a widespread move from users paying for how much they use to fixed charges for allocated calls and data (mobiles) and download speeds (broadband) – analogous to capacity in this context. In rail, access rights are clear with different levels of firmness to allow the infrastructure manager to make best of capacity and construct the timetable.

4.3. The box below describes how examples within energy – the gas transmission arrangements and electricity interconnectors – can also provide useful insights.

Gas entry arrangements

The arrangements for gas entry transmission provide a useful comparison. Existing capacity in the gas transmission network is allocated through auctions run by the SO. The auctions cover a range of capacity products with different durations (ie a mix of longer-term and shorter-term access rights). Auctions for longer-term rights include a reserve price methodology.

It is also possible to have secondary trading of rights between market participants. This means that there is in theory scope for the value of access to be priced by the market close to real-time, and for access to be re-allocated to those who value it most. Any auction premiums observed through this process can also provide an indication of constraints in the network that are candidates for reinforcement.
In practice, falling demand and changes in supply have resulted in excess capacity throughout the gas system suppressing congestion and hence the need to reallocate scarce capacity. As a comparison to the status quo electricity network access model however these arrangements may have merit.

Cross-border interconnection capacity allocation

There is a methodology for the short-term (day-ahead and intraday) and one for the long-term allocation of capacity on electricity interconnectors. Underpinning the methodologies there is a pan-European grid model[51] that calculates the available capacity to be allocated. This coordinated approach to calculating capacity calculation is intended to maximise the amount of cross-border capacity that can be release to the market for trading.

[51] The common grid model represents the European interconnected system based upon generation and load data in order to provide TSOs with accurate and timely information.

4.4. We see the options for reform to network access to be considered as broadly splitting into:

- Ensuring the choice of access options meets user needs efficiently
- Enhancing mechanisms for allocation and reallocation of the associated capacity to efficiently met user requirements

4.5. These are complementary. In order to give users a clear choice, it is necessary to have a clear definition of what the different options for access are. This greater level of definition would be necessary to support improved methods for (re-)allocating capacity, such as trading capacity between users.

4.6. In this chapter we illustrate how changes to a range of aspects of arrangements could potentially help. These illustrative descriptions are intended as a basis for further engagement and consideration, to be taken forward in conjunction with stakeholders.

4.7. Variants on these approaches could be adopted as part of a package with others or standalone. These types of mechanism could provide better information about the quantity of capacity and value users place on different type of access across the system. This could also enhance clarity and certainty for network operators about where there is available capacity or where new network capacity is needed.

A. Choice and granularity of 'products'

4.8. As discussed in chapter 3, at present users have limited ability to make choices about the nature of their access. As the system is changing, they are using the system in increasingly different ways. Providing more choice about how parties can access the network could help them meet their individual requirements better. It could also provide improved information to network operators about where new network capacity is needed.

Key options for providing choice could be:

4.9. **Time.** Users' need for network access isn't constant but highly variable. Increasingly, intermittent, flexible or potentially in future, mobile, usage patterns may mean that shorter duration capacity requirements or the ability to vary these dynamically are increasingly relevant.

4.10. Products could vary in duration, with longer or shorter term products. A clear long-term access product could provide users with long-term certainty of access, with commensurate links to charges. In particular, it could allow users to have greater certainty of charges over that period, while ensuring that user commitment requirements are commensurate with the certainty users receive (discussed further in the next chapter). The level of appetite for long-term access products would also give network operators better information about the need for new network capacity. Some users may prefer shorter-term access, for example if their assets have a limited lifespan or they are more flexible in when they use the system and able to respond when short-term access is cheaply available.

4.11. Products could also vary in the time profile of access rights, such as products for the different seasons, or for peak and off-peak periods. Profiled products could enable network operators to rely less on diversity assumptions (which may increasingly become hard to profile as usage patterns become more flexible), and allocate more capacity rather than leaving redundancy.

4.12. **Firmness.** Different users will place different value on different levels of 'firmness' of access. Some may have high requirements for firmness, while others may be more flexible, willing to accept reductions in capacity at certain peak times in exchange for lower forward-looking charges. The flexibility inherent in non-firm access means network operators can avoid costly network upgrades, saving users (and consumers more generally) money while allowing users to access capacity at lower cost where real time conditions allow. There could be scope to improve clarity for users about their rights under non-firm access, such as the circumstances that could trigger curtailment. There could potentially be caps for curtailment beyond which users would start to receive financial compensation. Increasing more choice around the extent of firmness could also help reveal better information to network operators about the value users would place on new network capacity.

4.13. There could be greater use of non-firm access at transmission level and, more generally, greater alignment of the approach to access for TG and EG where this could provide benefits. This could involve allowing EG that elects for firm access the ability to receive financial compensation for constraints in the same way as TG, though consideration would be needed to ensure that the charges for this access were adequately cost-reflective.

4.14. **Geography.** In some cases, constraints may limit the ability to access the wider network but there may continue be available capacity within a more localised area. Access rights could be defined with greater locational granularity, so that users could choose whether they just wanted access to the local network, and so could avoid having to pay (and potentially wait) for new network capacity to the wider network. This would mean that a user just buying this local access would only be able to trade with other participants in that local area of the network (as defined in their access product) and not nationally (including services to the system operator). The boundary could be set at different level(s). For example, it could be set at the transmission–distribution boundary such that only users that bought national access rights would be liable for transmission charges. In principle, the decision on where boundaries were set should be driven by where there are constraints on the network.

4.15. In order to provide clear choices, it will be necessary to better define key aspects of access products. There could also be value in introducing additional conditions, such as a clear requirement to release capacity if it wasn't used, to help get the most from the network capacity available.

4.16. It will also be necessary to consider which elements are the most important to provide choice around, and to consider whether different types of choice can and should apply to different user types (while not introducing undue distortions that could lead to worse outcomes for consumers).

4.17. For example, it will be necessary to avoid undue complexity in the range of choices available. This is a particular consideration for smaller users, though we note that intermediaries or automated technologies could support participation for some users, reducing the need for direct, active engagement by all.

4.18. A further consideration for households is the suitability of different options given that electricity is an essential service (as discussed in chapter 2). We think this will mean that some options would not be appropriate, and that safeguards will be needed to avoid undue distributional effects and impacts on vulnerable consumers in particular.

4.19. For example, all households might need a default access product for their core requirements. If a household has specific access requirements, for example to fast charge an electric vehicle at peak times, then one approach could be that they are offered options to pay for this additional access, with choices over whether that is peak or off-peak, or interruptible or not. Access which would trigger less incremental cost on the networks would be cheaper, with the aim of allowing users to meet their needs while providing them with an incentive to adjust their behaviour to reduce network costs, so that costs to consumers as a whole are no more than necessary.

4.20. A key question with such an approach would be how to define core needs, considering what type of network usage could be considered to provide for a reasonable basic level of access for all households, while ensuring that users wanting additional access beyond that receive an effective signal reflecting the cost that it would impose on the network.

4.21. Consideration would be needed as to how arrangements may need to differ between entry (adding energy to the system) and exit (taking energy off the system). Network users with on-site generation or storage would likely need both entry and exit capacity. Different arrangements may be appropriate for different sizes of users, in particular smaller ones.

B. How capacity is allocated and reallocated

4.22. A market for access products could develop, allowing users to signal the value they place on different types of access and giving greater flexibility to adjust their capacity over time to better fit their needs. This could allow forward-looking charges to be more closely tailored to the nature of the product (discussed in the next chapter).

4.23. If access rights are more clearly defined, then there is potential scope to develop a market for these rights. This could help the market reveal the value of network access more accurately and dynamically than possible through a regulated charging approach. As with the options to provide greater choice, this can help bring costs down for consumers by ensuring that users that value access most can obtain it, and provide improved evidence as to the need for new network capacity.

4.24. One option to create more of a market for access rights would be to move away from the 'first-come-first-served' basis for allocating capacity to a process where access rights are obtained through regular, periodic allocation windows, such as auctions. This would enable access to be secured by those who value it most (including new entrants), avoiding potential inefficiencies caused by connection queues, for example:

- in a more classical auction users would bid for a given amount of capacity, over a defined period of time, at a particular node or zone in the network.
- alternative mechanisms could be designed to reveal users' valuation of network access in parallel with the apportioned cost of providing that capacity in an area.

4.25. The duration of product being bought would need to be clear. Many network users would want long term certainty of their network access to reflect the fact that the assets they own and develop have commercial operation that may be decades long. If long term products were offered in auctions, with a corresponding length of user commitment, this could also provide a strong signal to inform efficient investment in network capacity, based on a good understanding of users' requirements. Equally, shorter term products would provide a good signal for flexibility providers to release capacity.

4.26. Auctions are unlikely to be a suitable means for all user types to obtain access. In particular, they would be unlikely to be appropriate for individual households to get the access they needed for essential services. Auctions appear particularly well placed for entry capacity (ie putting energy onto the system) – consideration would be needed of the arrangements for micro-generators and the implications of potentially having different arrangements for entry and exit capacity allocation.

4.27. Another option would be to make changes to facilitate secondary trading of access. This can have inherent benefits as a way of enabling limited capacity to be used most effectively where some users would derive greater value from its use than others. Transparent and liquid mechanisms would be needed to reallocate capacity or obtain shorter term capacity products. This would help give users confidence that they could obtain the short-term variation in access they require. An alternative way by which users might trade access is in relation to 'non-firm' access products, where users could potentially exchange the curtailment risk they faced in operational timescales.

4.28. The value of a capacity product can be highly locationally specific. Trading of access or curtailment at one point on the network for use at another would need to reflect this difference. For example, this might mean access could only be traded in a certain area or that there could be an "exchange rate" between different locations. Trading could be supported by the relevant system operator(s) or by an independent market platform, potentially informed by network models. As above, network planning and incentive arrangements would need to ensure capacity was made efficiently available to market participants.

4.29. As with other options, consideration would be needed as to how trading might apply to different types of user. The essential nature of electricity means that we would want to ensure that households can always access the network. For example, all households might need a default access right to represent a reasonable basic level of access which could not be traded on. Beyond those default rights, they might then need to purchase additional products for access, with potential choices over whether that is peak or off-peak, or interruptible or not. As noted above, a key question here would be how to define the core level of access.

Wider links and enablers

4.30. These approaches are likely to need improved knowledge about network capacity availability and utilisation if it is to allow more efficient use of the network while maintaining reliability. This includes what notifications users need to provide about how they intend to use their rights, and monitoring how users are adhering to the conditions of their access rights. There would also be dependencies with planning standards, where the relationship between the quantity of rights made available, and physical network limits may need review, particularly in a world where the diversity assumptions evolve. Obligations and incentives on the network companies would need to be considered to ensure they played their role in ensuring capacity was made available and used efficiently.

4.31. There would also need to be consideration of how changes worked with wider market arrangements. This includes the link to settlement arrangements, which particularly may need to be adjusted if access rights have greater locational granularity. It would also require consideration of what rights users need to have to be able to participate in different markets, including the capacity market, contracts for difference auctions, and service provision to the system operators.

Key questions related to access arrangements

4.32. There are a range of key questions which would need to be considered in taking forward thinking on the potential for any changes in this area, including:

Choice and granularity of access products

- Which types and granularity of products could have most value, for both users and network operators, taking into account the need to avoid undue complexity and (potentially) support trading of rights?
- In what circumstances might specific conditions on rights, such as a requirement to release unused capacity, have value and where / how might they be feasible?
- How should access for households be treated to ensure that basic needs can be met without undue distributional effects, while providing improved signals for additional usages?
- To what extent does there need to be similar approaches across different types of user to ensure a coherent overall framework?
- How would any different products interact with wider market arrangements?

Allocation and reallocation

- How might periodic allocation of access rights work, including for different types of users, particularly taking into account the need to support efficient investment in new energy resources?
- What would be needed to support effective reallocation or secondary trading of access, and how significant are any barriers to this?

5. How might changes to network charges support better outcomes?

5.1. In this section we describe the options for changing forward-looking charges to address the problems with the current arrangements. We first consider what changes might be necessary if there are no major changes to access rights. We then look at how this might change if some of the access right options were taken forward.

Options for changes to the forward-looking charges

5.2. There are some changes to individual charges that could bring benefits to consumers. We describe these in terms of which group of building blocks they relate to (i.e. either *structure of charges* or *granularity of charges*). We then discuss cross-system changes that could be made, affecting a number of charges, which would also involve changes to both the structure and granularity of charges.

Changes to individual charges - structure of charges

5.3. **Basis of charges.** It may be beneficial to rebalance the overall basis of charging between fixed charges, volumetric charges, and capacity charges. This could mean that forward-looking charging structures better reflect how users drive costs on the system. In practice, this could mean reducing volumetric charges, (kWh) and increasing the proportion of charges which are based on a user's capacity (kW). For users without clearly contracted capacities, this could be done based on maximum metered demand, similar to how demand TNUoS is levied based on triads. There are many options for how this would be implemented in practice, depending on users' time of use (see next subsection on granularity).

5.4. Charging structures should also be designed to ensure that on-site generation, storage or demand-side response receive appropriate signals. For usage-based charges, this could involve charging on net amounts, as it is the net level of peak capacity which ultimately drives incremental cost.

5.5. **Timing of payment and degree of user commitment.** Changing *when* charges are paid might also address some of the problems. For example, requiring ongoing user commitment through clearly defined liabilities and security deposits could improve the allocation of investment risk. Allowing distribution connected users to pay for connection assets over the lifetime of their connection commitment instead of upfront, could also reduce potential distortions caused by the difference between the depth of the transmission and distribution connection charging boundaries.

5.6. **Types of costs.** Charging structures need to continue to include all relevant costs which network operators incur, and map these to the correct drivers. This might include the newer types of costs that DNOs may incur as they increasingly take on DSO roles, for example, expenditure on smart grid assets and flexibility services. There may also be merit in including signals about the costs of asset replacements (due to age and condition) within forward-looking charges.

Changes to individual charges - granularity of charges

5.7. There are many incremental changes to the granularity of charges which could be beneficial, particularly within the distribution charging methodologies. The rollout of smart meters and introduction of HHS will allow for the introduction of more granular charging arrangements.

5.8. **Locational granularity.** There may be benefits to simplifying EDCM charges in order to minimise volatility, increase transparency, and clarify locational signals. There are many options for how this could be achieved (eg simplifying the underlying power flow methods within the EDCM or reducing the level of locational granularity). This may also help DNOs to provide better tariff forecasts for customers, which would potentially make these signals more useful.

5.9. There may also be a case for introducing locational charges for generators into the EDCM, given the continued growth in deployment of EG and other distributed energy resources.

5.10. More locational granularity for both generation and demand users could be beneficial within the CDCM. Generators currently receive credits as default under the CDCM. However, this may be distortive in locations where generation is not offsetting reinforcement, but actually driving reinforcement costs (eg 'generation dominated areas'). In relation to demand, if electric vehicles and heat pump technologies were to 'cluster' in certain areas of the network, then more locationally-specific charges could give more cost-reflective signals to specific users to adjust their usage to offset the need for network reinforcement in that area.

5.11. Greater locational granularity may be difficult to achieve at lower voltages given the size and extent of these networks and the number of assets involved. However, it might be possible to define average charges for certain network archetypes (eg 'generation-dominated' or 'demand-dominated'). Further consideration would also need to be given to the distributional effects of greater locational granularity, particularly for vulnerable consumers.

5.12. There may also be an option to introduce greater locational granularity in the short run marginal cost of operating the system (eg through a locational BSUoS charge). This was considered by the Competition and Markets Authority (CMA) and as a result locational pricing for transmission losses will be introduced shortly. Other SRMC could potentially be priced locationally, including the cost of constraints and of voltage control. It would be important to ensure that any cost reflective BSUoS methodology (or similar charge) does not create any double charging with TNUoS charges.

5.13. **Temporal granularity.** Temporal granularity needs to be considered if using charges based on metered kW demand, either within existing arrangements or if these charge are introduced for other users as part of any reforms. Within TNUoS, it may be worth considering whether other periods other than triads may be driving costs eg should charges be used to provide charges or credits associated with low demand periods.

5.14. Charging based on a user's individual peak demand, irrespective of when this occurs, is unlikely to be fully cost-reflective[52] if the charge does not also consider wider system conditions. For example, a user who has a high peak demand during the summer is unlikely to drive much incremental cost. Instead, users could be charged based on their coincident peak demand during certain peak periods. This might also need to be granular enough to consider a wider range of local and seasonal peak and through conditions which drive investment, particularly for distribution charging. There may even be an option for dynamic Time of Use (ToU) tariffs, although this could be complex and challenging to implement.

[52] Although this may still be an improvement over volumetric charges.

Where could cross-system changes to the charging methods be beneficial?

5.15. More fundamental reforms which significantly change forward-looking charges across the system could also bring benefits.

5.16. The options identified below are not a definitive list of the possible reforms that could be made. We recognise that some of these options represent a significant change from the existing arrangements, and so it would need to be clear that there were material distortions arising from existing arrangements in order to justify the implementation costs involved.

5.17. Network operators could implement changes to charging structures to harmonise these across the whole system. For example, making the forward-looking charges for different types of generation more consistent would remove the distortions which exist due to the different TNUoS and DUoS arrangements. Currently smaller EG is treated differently than larger EG and TG in terms of TNUoS charges, and EG is treated differently at EHV levels compared to lower voltage levels for DUoS charging.

5.18. Harmonising the connection boundary across transmission and distribution would be another option. Changing the depth of either boundary would be complex, though it may be simpler to make the distribution boundary shallower. A shallower boundary would fit with the argument that a connection charge works best for assets where it is clear and stable upfront what portion will be used by a particular user. This may decreasingly be the case for anything other than single use assets due to the greater scope for dynamic flexibility in how network capacity is allocated (as a result of active network management capability). If the connection boundary were changed, consequential changes would also be needed to the use of system charges to ensure overall arrangements are cost-reflective.

5.19. There could also be other changes to unify use of system charges to ensure they adequately reflect how users could cause or relieve costs across the whole network. To achieve greater harmonisation across the system, it may be beneficial to harmonise the TNUoS and DUoS tariff setting approaches. This could result in more 'realistic' approaches and assumptions being used in all of the models, such as explicitly including spare capacity within the TNUoS model.

5.20. In the extreme, this could even involve moving to a single network charge, which represents the entire network within one tariff setting method and model. Although theoretically possible, this may be infeasible to implement in practice (at least in the near-term), given data limitations for the lower voltage levels of the network, and the complexity of calculating power flows and resulting charges. In addition, as noted above, TNUoS for generators (and some of the fixed and capacity charges within DUoS) works on a different basis from other charges in that it is an access rather than a usage based charge, and so any harmonisation would need to take that into account.

5.21. Instead, greater coordination across the whole system[53] could also be achieved through new agency models[54] for charging, such as allowing network companies to levy charges on each other which they then recover from their users, or changing the way that suppliers have to pay for different types of charges on behalf of their customers.

[53] Setting charges and giving signals in order to achieve outcomes which are efficient across both transmission and distribution.
[54] Some users may not directly contract with the network operator and may have an agent to do this on their behalf, eg a supplier or another network operator.

5.22. Another area where there could be potential for significant reform is in charging for constraint management costs paid by the system operator and, potentially in future, distribution system operators. This could lead to the creation of a new type of distribution charge that mirrors BSUoS, which might use a granular locational methodology for costs associated with, for example, constraints and reactive power. It is not clear how well this would work alongside a totex approach to DNOs' allowed revenues.

5.23. Alternatively, the constraint payments element of BSUoS could actually be moved to be recovered under TNUoS. This may particularly be relevant if there is merit in ensuring that constraint payments costs are recovered in a more cost-reflective way, as the drivers of these costs are the same as those driving network investment. Combining TNUoS and BSUoS into one charge could allow synergies and ensure that there is no double charging.

What changes might be needed to charging given the potential changes to access rights?

5.24. Many of the options above could bring benefits irrespective of whether network access arrangements are reformed. But, there are further reforms to the structure and granularity of charges which might be required if access arrangements are changed.

5.25. In general, having more defined and tradeable access rights could involve a move away from usage based charging (either volumetric or demand) towards access-based charging throughout the system, ie potentially larger ex ante capacity and fixed charges. These would have to be set in a way that users pay for both the import and export capacity that they require. For example, demand users with onsite generation would need to pay for export access if they ever wished to export electricity back to the network.

5.26. It might be necessary to reflect variation in different types of rights in the charges that are applied (eg local access right, seasonal rights or peak access rights) to reflect how different types of rights drive network costs. It could also be possible to distinguish between long-term access rights and short-term access rights with different types of pricing. A user may be required to pay the LRMC to get access in the long term (eg to facilitate their overall connection to the system), whereas charges for those using short-term access (or who are "over-running" their allowed capacity allocation) might reflect SRMC.

5.27. If users have the option to acquire a long-term access product, this could involve fixing the level of the charge they would pay for this access over that period. If charges are appropriately cost-reflective, then to an extent this would be similar to a deep connection charge (though they would have the ability to sell on their access to others, whether permanently or for a certain period). This would allow for charges which are highly cost-reflective and granular. This could mean that charges vary significantly over time for those choosing to purchase these rights for the first time, but users would be able to protect themselves against this volatility by fixing their charges.

5.28. For users who wish to choose long-term access rights it would be reasonable to expect these users to make a long-term financial commitment towards their access. This could take the form of early exit charges, or contain requirements for securities against this liability. This could improve the allocation of investment risk of network investment between those that trigger the investment, network operators and consumers more generally.

5.29. Finally, charges would need to be modified in the event that access rights are allocated using an auction mechanism. Auctions would replace the need for forward-looking charges, though the charging methodologies could still potentially have a use in setting auction reserve prices. In the event that network operators earned revenue from an auction in excess of that agreed in a price control, this may need to be reflected elsewhere in the charging methodology (eg by a reduction in residual charges).

Key questions related to charging

Questions about the structure of charges

5.30. Key questions related to the structure of charges in considering which options might be preferred would be:

- Which costs are most appropriate to recover from which types of charge? For example, to what extent should the indirect costs of the networks be allocated through forward looking charges? Should the short-run and long-run marginal costs of the system be recovered through separate or combined charges, and how might this be achieved while ensuring that there is no 'double-counting' of any cost drivers?
- What is the most appropriate charging basis for each of type of cost and each type of charge? How frequently should these charges be set and should this be done ex-ante or ex-post? Is there value in having distinct charges for reactive power? What are the advantages and disadvantages of hybrid connection and access charge, like the charge that arises with a shallow-ish connection boundary? How might this change if the allocation of network capacity becomes more dynamic?
- Is there a case for all users to make a greater ongoing commitment to the cost of the network investment that they trigger?
- To what extent is it necessary to have different arrangements for different types of users (eg generation and demand)?

Questions about the level of granularity of charges

5.31. Key questions related to the level of granularity of charges in considering which options might be preferred would be:

- What level of granularity of charges will create the most value both for users and network operators? How does this vary across different voltage levels and types of user? What is the relative value of high levels of locational granularity compared to high levels of time of use granularity? How should the trade-off between granularity and volatility be managed?
- Should charges be used to provide signals of relative cost impacts or signals of absolute cost and is it important to distinguish between these? Can relative cost signals be efficiently preserved for all types of users in different parts of the system?
- What approaches could be used to ensure that the charges faced by users reflect costs imposed across the whole system? What are the strengths and weaknesses of each approach?
- What boundaries within the system should be used to define different charging arrangements now and in the future?

6. Taking this work forward

Our next steps

6.1. We will be developing our thinking on these options, and the underlying evidence for reform, over the coming months.

6.2. This will include consideration of who should be affected by different aspects of reform, and the relative timing of different aspects of reform and other regulatory changes such as those in the Targeted Charging Review and RIIO-2.

6.3. In particular, we will examine the advantages, disadvantages and ease of implementation of the different options we set out in chapters 4 and 5. Our consideration of the options will be based on the building blocks we set out in the following framework:

<table>
<tr><th colspan="2">Network access arrangements</th><th colspan="2">Forward-looking charges</th></tr>
<tr><td rowspan="5">Nature of access rights</td><td rowspan="2">Time aspects</td><td rowspan="4">Structure of charge</td><td>Types of costs</td></tr>
<tr><td>Types of charge</td></tr>
<tr><td>Firmness</td><td>Basis of charge</td></tr>
<tr><td>Geographical nature</td><td>Timing of payment and degree of user commitment</td></tr>
<tr><td>Associated conditions</td><td rowspan="3">Level of granularity</td><td>Locational granularity</td></tr>
<tr><td rowspan="2">Allocation and reallocation</td><td>Initial allocation</td><td>Types of locational signal</td></tr>
<tr><td>Reallocation and trading</td><td>Temporal granularity</td></tr>
</table>

6.4. At this stage we think it is necessary to consider the options holistically given the extent of interlinkages, but we expect any initial proposals to involve some prioritisation of which areas will be taken forward initially. This will be based on the issues where the potential for consumer benefit is highest. We will be undertaking analysis to support the prioritisation of issues over the coming months.

6.5. In addition to undertaking our own analysis, we want to use input from industry to help develop and appraise the options. To this end we are setting up two Task Forces under the Charging Futures Forum, discussed further below.

6.6. We will also continue to engage with stakeholders about the potential options for reform. This will involve hosting workshops with interested parties. This is discussed further in chapter 7.

6.7. We will use feedback from these sessions, the work completed by the Task Forces and our own work to inform our view on whether and what reforms are needed. We anticipate consulting on our initial proposals for reform, if needed, in summer 2018.

6.8. We expect that this consultation will provide further information on how we will take implementation of any reforms forward. For example, it could include a proposal to launch a significant code review, or other possible implementation routes. We would set out the expected implementation timescales as part of consultation.

6.9. We recognise that some of the options being considered may have implications for existing network users, as well as new network users. We will consider the impact on and benefits to existing and future consumers in any initial proposals for reform. We will also consider whether transitional arrangements would be appropriate as part of assessing the different options for reform.

6.10. Following our consultation in summer 2018, we envisage setting out our proposed next steps later that year. This may involve launching a significant code review.

6.11. This project is closely linked to wider Ofgem work (eg RIIO-2, Targeted Charging Review and Smart Systems and Flexibility work). We will ensure that these projects remain coordinated and aligned.

Task Forces

6.12. In order to gain industry expertise to help inform option development we are setting up two Task Forces under the CFF. The work of these Task Forces is closely linked. The two Task Forces will be closely integrated to ensure that we develop a holistic, coordinated approach to reform. To ensure that this happens, the Task Forces will hold joint meetings on a regular basis and have mirror terms of reference. The Task Forces will also have a common Chair and a common Secretariat. We also expect the Task Forces to produce common documents. The two Task Forces are:

1. **Access Task Force** – helping develop a clearer view of what changes to network access arrangements could drive benefits to consumers, and key challenges to be worked through.
2. **Forward looking charges Task Force** – helping to clarify what changes to the forward-looking element of network charges could drive benefits to consumers, including considering what changes would need to be made in light of any changes to access rights.

6.13. The Task Forces will develop options to address the issues we have identified, using the ideas in this document and also considering the specific questions that we posed. The Task Forces will then identify advantages and disadvantages, and risks and opportunities of these options, and publish their conclusions by April/May 2018.

6.14. We also expect that the Task Forces will help inform and input into our prioritisation of issues (eg providing data where relevant).

6.15. The draft terms of reference for each of these Task Forces is outlined in Annex 1. There are specific outputs that the Task Forces need to meet within specified timescales. Most notably the Task Force will need to work with Ofgem in order to meet the following timescales:

Deliverable	Dates
Produce a document identifying the initial options agreed for further assessment.	December 2017/January 2018
Produce a document assessing each of the initial options, based on the agreed assessment criteria.	February/March 2018
Produce a report outlining the TF's conclusions on what changes should be taken forward for further consideration	April/May 2018

6.16. We will chair the Task Force meetings to ensure that it delivers the outputs within the specified timescales. We will also actively participate as a Member of both Task Forces. We intend to actively feed into the options developed to ensure that the analysis adequately reflects consumers' interests.

7. How to get involved

7.1. We are keen to work with industry to develop our thinking. There are plenty of opportunities for you to find out more about this work and contribute your views.

Task Forces Members

7.2. We are inviting members of the CFF distribution list to become Task Force members. The CFF is an inclusive group that is open to network users, network operators and energy consumers and/or their representatives. The CFF enables stakeholders to provide policy input and technical expertise for policy developments. The CFF keeps stakeholders informed about progress of various work areas, including access rights and forward-looking charges reform. If you want to find out more about the CFF or would like to become a Member then please contact chargingfutures@nationalgrid.com.

7.3. More information on our expectations for Task Force members can be found in the draft Terms of Reference for the Task Force in Annex 1. The first Task Force meeting will be held in late November/early December and will be joint between both the Access Task Force and the Forward Looking Charges Task Force.

7.4. If you would like to find out more information about the Task Forces or would be interested in becoming a Task Force Member then **please email networkaccessreform@ofgem.gov.uk by 10 November 2017.** As part of your expression of interest please outline:

- Which Task Force you are interesting in becoming a Member of,
- Your contact details,
- The organisation that you will be representing,
- Any relevant expertise and experience,
- Whether you will be able to contribute towards the work of the TF outside of the TF meetings, and
- Why you consider that you would make a good TF Member.

Non-Task Force Members

7.5. The Task Forces will be required to keep the industry and non-members up-to-date with its progress (eg via updates to the CFF and the ENA Open Networks). The Task Force will also be required to publish documents on the CFF portal. Non-Task Force members will also be able to contribute opinion and analysis to the Task Force.

7.6. We will engage with stakeholders about issues with the current arrangements and options for reform. We will hold several workshops to allow stakeholders to discuss the proposals in more detail. We will advertise these via the CFF.

7.7. Non-Task Force Members will also be able to respond to our planned consultation on initial proposals for reform of electricity network access, which we expect to publish in summer 2018.

7.8. If you have initial comments or questions on this paper or would like to be kept up-to-date with our work on electricity network access reform, please email us at: networkaccessreform@ofgem.gov.uk.

Annex 1 – Draft Terms of Reference for the Network Access Task Force and Forward-Looking Charges Task Force

*We note that these are **draft Terms of Reference (ToR)** and that they are subject to change. The ToR will be common for both TFs.*

Introduction

The purpose of this Task Force (TF) is to carry out the work assigned to it by the Charging Futures Forum (CFF). Specifically, this TF will help consider what changes should be taken forward to drive benefits to consumers through supporting more efficient use and development of network capacity.

The work of the Network Access TF is closely linked with the work of the Forward-Looking Charges TF. The work of these two TFs must therefore be coordinated.

The objectives of the TF are to assess the issue in detail, develop solutions and agree conclusions based on robust analysis. The TF's work will be informed by Ofgem's working paper published in autumn 2017. The work of the TF will input into Ofgem's consultation in summer 2018 on initial proposals for reform.

The Network Access TF and Forward-Looking Charges TF will, in coordination with each other:

a) Carry out the work assigned to it.
b) Liaise closely with the CFF and Energy Networks Association (ENA) Open Networks Project and regularly report back on its progress and findings.
c) Engage with the wider industry (eg Smart Systems Forum) to help inform their thinking. The TF has flexibility about how it engages with the wider industry (eg formal consultation paper or industry workshops).
d) Commission work from subgroups where necessary.
e) Produce a set of conclusions and present these to Ofgem, the CFF and the Charging Delivery Board (CDB).

1. Scope

a) In accordance with the timetable identified in paragraph 8 and in coordination with each other, the Network Access TF and Forward-Looking Charges TF will:

    i. Inform Ofgem's assessment of the issues with the current arrangements. This will build on the list of issues identified in Ofgem's working paper published in November 2017.
    ii. Develop a set of detailed options to address these issues. The detailed options should be informed by the options identified by Ofgem in its working paper.
    iii. Agree a set of criteria for assessing the advantages and disadvantages, as well as the risks and opportunities, of each detailed option. The criteria should be informed by the desirable features for access and forward-looking charging arrangements identified by Ofgem in its working paper.
    iv. Undertake an assessment of each detailed option, based on the agreed assessment criteria. The analysis should include a reasonable

qualitative and, to the extent possible, quantitative assessment of the impact of each option. It should also have regard to the questions about different options set out in Ofgem's working paper.

v. Agree a set of conclusions.

b) not duplicate the work of workgroups under the code modification development process.

2. Chair

The TF will be chaired by Jon Parker or Andrew Burgess from Ofgem. The TF chair may nominate a deputy to chair the meeting in their absence.

The Chair will provide leadership to the TF and will be responsible for ensuring that each meeting is conducted in accordance with the ToR and in an orderly efficient manner. The Chair will ensure that all TF Members are able to contribute their views to the TF. The Chair will coordinate with the Secretariat to ensure that appropriate policies and procedures are in place for the effective management of the TF.

3. Membership

TF members

Membership will be drawn from members of the Charging Futures distribution list (CFF Members are able to nominate an alternative representative from their organisation). The TF should include Members that are representative of a range of industry viewpoints. This will include representation from system and network operators but also from wider industry.

If a TF Member is unable to attend a meeting, the TF will be able to nominate an alternate to attend the meeting on their behalf.

Ofgem may provide at least one member to the TF, in addition to the Chair.

TF Members will:

a) have relevant expertise and experience;
b) be committed to making improvements to delivering benefits to consumers through more efficient use and development of network capacity;
c) be available to attend all meetings (or send an appropriate alternate representative);
d) be able to work collaboratively with other industry participants that may have different views and seek to find consensus, where possible; and
e) actively contribute towards the work of the TF outside of TF meetings. This will include being responsible for completing tasks (eg undertaking analysis) that have been allocated to a Member by the TF and reporting back to TF; and
f) be expected to contribute towards the milestones outlined in paragraph 8. For example, collectively TF Members will be expected to draft the final report outlining the conclusions of the TF.

We would expect each TF Member to contribute to the work of the TF. We are willing to accept a lower level of contribution for representatives from smaller organisations.

Depending on the level of interest, we may limit the number of TF Members from each representative group to facilitate productive meetings and in-depth discussion. In this situation, we will firstly ask the relevant parties to agree a nominated representative. If the parties are unable to agree a nominated representative, then the Chair shall decide the nominated representative.

CFF members

The TF will provide regular reports and updates to the CFF Members on its work and progress. CFF Members will be able to review all published TF documents and be able to contribute opinions and analysis to the TF via the Secretariat. Ofgem will also continue to engage with the industry directly. For example, Ofgem will host several workshops to discuss issues and options for reform.

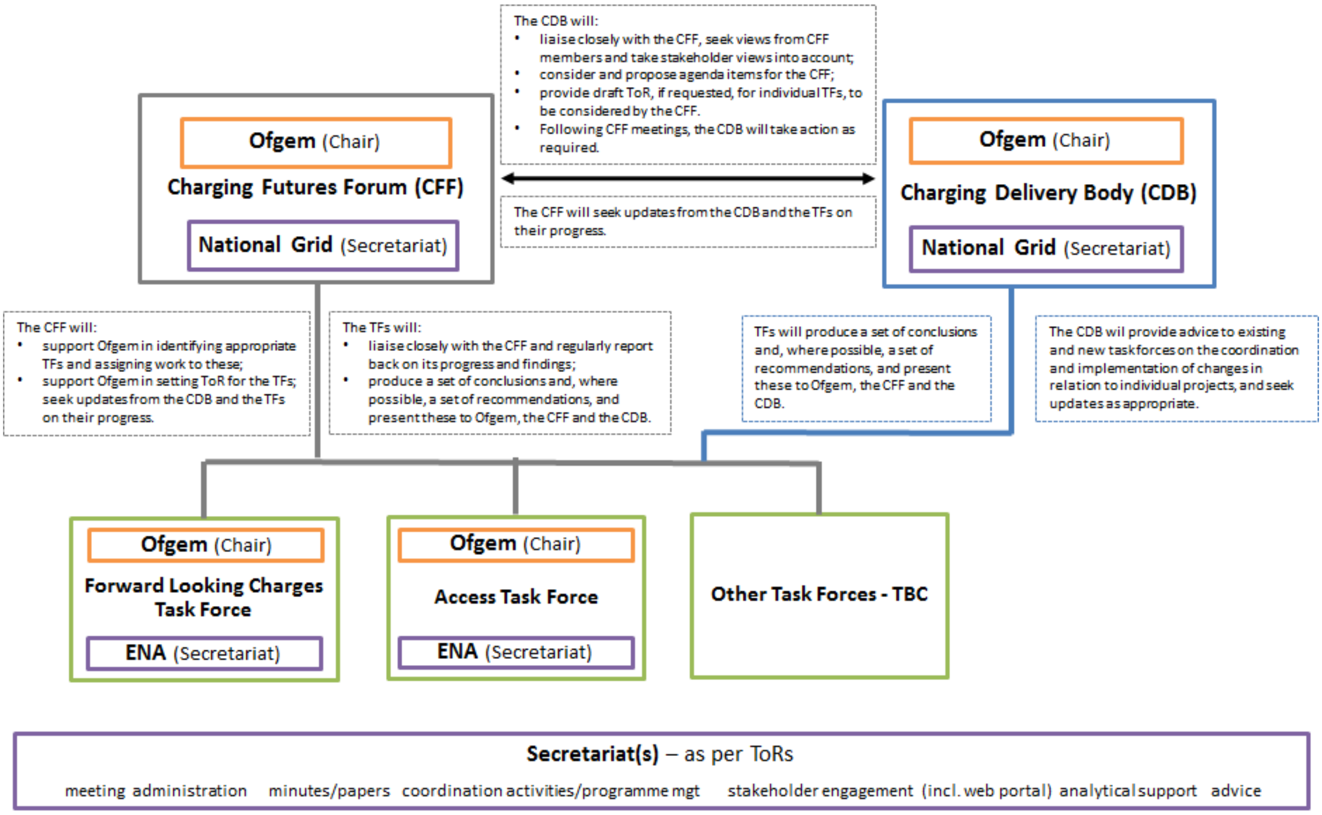
4. Secretariat

The Secretariat role will be undertaken by the ENA.

The Secretariat will:

- a. Provide secretariat services to the TF and the Ofgem Chair:
    - i. Organise meetings, including booking venues, in consultation with Ofgem.
    - ii. Send out meeting invitations.
    - iii. Prepare agendas, minutes and collate other papers.
    - iv. Circulate meeting agendas and supporting documents/papers five working days prior to each meeting according to the timeline in the TF ToR.
    - v. Circulate minutes to TF Members after each meeting.
    - vi. Share all agreed meeting documents with the Lead Secretariat who will add them to the TF section of the CFF portal.
    - vii. Maintain membership lists of TF meetings. Handle membership applications and refer applications for joining the TF to Ofgem.
    - viii. Maintain a list of TF actions and send reminders to TF Members to complete their actions.
    - ix. Produce and update a detailed project plan to allow the TF to deliver its outputs in accordance with the timetable outlined in paragraph 8.
- b. Have sufficient understanding of the issues being discussed in order to successful complete its role.
- c. Manage stakeholder engagement for the TF arrangements:
    - i. Act as first point of contact for stakeholders who wish to contact the TF.
    - ii. Create and maintain a distribution list of TF Members.
- d. Provide the necessary information to enable the Lead Secretariat for the Charging Futures Forum to maintain the TF section of the CFF portal. The TF section of the CFF portal will provide stakeholders with information including:
    - i. A calendar of upcoming meetings of the TF.
    - ii. Membership of the TF.
    - iii. Papers and other documents for TF meetings.
    - iv. Contact routes for stakeholders wishing to communicate with the TF.
- e. Collate and publish the final TF report on behalf of the TF.

5. Relationship with related bodies



6. Reporting and output

The TF will provide regular reports and updates to the CFF on its work and progress. The TF will also be required to keep wider industry updated on its work through the regular publication of all agreed TF documentation (ie documents that a party asks not be circulated or documents that are only available in draft form do not need to be published).

The TF will be required to provide a report to CFF, the CDB and Ofgem. The report will provide deliver the outputs identified in paragraph 8, in the timescales outlined.

The report should be a joint report on behalf of both the Access and Forward-Looking Charges TFs. For the avoidance of doubt the TF is an industry forum that is independent of Ofgem. The TF's report represents the conclusions of the TF, not Ofgem. Ofgem will consider the TF's conclusions, but is not bound to act in accordance with them. Opinions expressed in the report will be those of the TF and do not bind individual TF Members from expressing alternative views.

7. Meetings

The first meeting of this TF will be held late November/Early December 2017. We expect each meeting to be at least 180 minutes long. The TF meetings will primarily face-to-face, however the TF can decide to meet via alternative methods (eg teleconference). The Secretariat will arrange alternative arrangements (eg teleconferences) for those that are unable to attend in person.

Meetings of this TF will be held roughly on a monthly basis, in the first instance. Meeting frequency will be reviewed on a regular basis, as decided by the Chair, in consultation with the TF members, as appropriate.

8. Timetable

The joint TF reports to the CFF/Ofgem should be completed in accordance with the following timetable:

Date	Task
December 2017/January 2018	Produce a document identifying the initial options agreed for further assessment. Identify a set of criteria for assessing the advantages and disadvantages, as well as the risks and opportunities, of each detailed option. The TF criteria will take into account the CFF criteria for prioritising changes. This will be informed by Ofgem's working paper published in Autumn 2017.
February/March 2018	Produce a document assessing each of the detailed options, based on the agreed assessment criteria. The analysis should include a reasonable qualitative and, to the extent possible, quantitative assessment of the impact of each option.
End of April 2018	Produce a report outlining the TF's conclusions on what changes should be taken forward. The TF Members should try to find consensus on the drafting of the report. Where consensus is not possible, then the report should highlight any points where TF Members have conflicting views.

Following the production of the TF report by the end of April 2018, the TF will have completed the work outlined in this ToR and it is expected that the TF will close. This may be revisited subject to the outcome of Ofgem's decision on next steps.

*We note that these are **draft Terms of Reference** and that they are subject to change.*