Assessing the current issues with electricity network access and charging

CLIENT: Ofgem

DATE: 18/07/2018

Version History

Version	Date	Description	Prepared by	Approved by
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1 Executive Summary

Baringa was commissioned by Ofgem to develop an analytical framework to identify and assess the current inefficiencies within network access and forward looking charging arrangements. This was to inform Ofgem's review of the need for reform. This includes identifying where these inefficiencies are most material, and have the largest impact on existing and future customers. Our analysis is explicitly concerned with the materiality of issues with current arrangements, and does not comment on the addressability of each area or issue, nor which policy options would be most suitable to address these impacts, which Ofgem is separately considering.

The electricity system in GB is experiencing one of the most rapid changes since the markets were liberalised in the 1990s, driven by the need to decarbonise, step changes in technology, and the evolving expectations of customers. As demand and supply become more volatile and unpredictable, the arrangements for access and forward looking charges will need to evolve.

Current arrangements for network access and charging were designed in a world of mainly centralised (and controllable) generation, fairly predictable uni-directional network flows and before the advent of smart metering. Current industry governance is struggling to keep up with the pace of change now being witnessed.

In November 2017, Ofgem issued a working paper titled *Reform of Network Access and Forward-looking Charges*[1] which set out the issues, potential building blocks for options for reform, and the plan to address the key regulatory gaps in this area, working in conjunction with industry. Starting from the issues defined in this paper, we have defined a set of 22 issues with current arrangements and assessed their distributional impacts on a qualitative basis, supported by quantitative metrics where available. These issues were the basis for an assessment of the wider system impact in terms of **deployment barriers**, **efficiency of operations**, **efficiency of investment**, and **allocation of risk**. We considered the impact on the transmission network, the distribution network and the interface between the two.

We conclude that the most material issues with current arrangements fall into the following areas:

- **Ensuring that access and charging arrangements for small users are ready for the uptake of Low Carbon Technologies (LCTs).** Under current arrangements for small users, there is a risk that new loads like Electric Vehicles (EV) and Heat Pumps (HPs) create significant pressures on networks at peak times. This could lead to expensive reinforcement of the network, or potentially could lead to delays to uptake. The current charging arrangements would mean that the costs of required reinforcement would not necessarily be charged to those users who are creating the requirement, and therefore there is insufficient incentive on more flexible usage. For example, we estimate that a domestic customer with a standard domestic 3.5kW EV charging point will double its contribution to peak demand (without managed charging), and yet its DUoS charge would increase by only around 50% under current arrangements.

[1] https://www.ofgem.gov.uk/system/files/docs/2017/11/reform_of_electricity_network_access_and_forward-looking_charges_-_a_working_paper.pdf

- **Ensuring that access for distribution connected generation and storage is properly valued and signalled to users.** As of May 2016, there was 20 GW of accepted offers for connection of generation at distribution level[2]. Of this capacity waiting to connect, a material proportion will likely drop out for reasons unrelated to network access and charging. On the other hand this metric will not include potential applicants who are deterred from requesting connection, due to a publicised lack of capacity in a desired location. Overall, the development of Distributed Generation is expected to continue to grow, with an increase of at least 10 GW of capacity expected by 2030[3]. Other supporting evidence for access issues at distribution includes the number of flexible connections now being offered and accepted, in lieu of firm connections. Overall, there is a lack of locational and temporal signals for the value of capacity to existing and new distribution users, which means that capacity is not allocated on either a short or long term basis to those who value it most. In addition, the current approach of offering firm capacity may lead to lower utilisation of assets. Significant investment could be required to accommodate new generation on a firm basis: estimates for the potential avoidable network reinforcement cost through use of flexible connections by 2040 are up to £1.2bn.
- **Aligning access and charging between transmission and distribution, and across voltage level boundaries.** There are substantially different approaches to capacity allocation connection charging and use of system charges across voltage level boundaries, which creates the risk of distortions to investment decisions, primarily between transmission and distribution connected generation. This issue may also contribute to the size of the distribution connection queue.

Other issues include the socialisation of transmission constraint management costs such that charges are not reflective of the cost a user imposes on the network, and the lack of predictability of certain use of system charges for users.

For other issues or wider system impacts, rated as low materiality, the evidence that there is a defect that needs addressing is less strong, and hence these issues may not be focus for the current network access and charging review. However, if they are not taken forward under the current review then other methods for addressing these (e.g. through standard code governance) may be considered.

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[2] The size of the queue may be an indicator of issues outside of the scope of this report, such as the discrepancy between residual charging for transmission and distribution which favours connection to the distribution network.

[3] National Grid Future Energy Scenarios (FES) 2017, all scenarios project an increase in embedded generation capacity of at least 10 GW by 2030

2 Introduction

Baringa was commissioned by Ofgem to develop an analytical framework to identify and assess the current inefficiencies within electricity network access and forward looking charging arrangements. This includes identifying where these inefficiencies are most material and have the largest impact on existing and future customers. The scope of the work covers both access (connection) and forward looking (use of system) charges at all voltage levels (transmission and distribution), for all user types across both entry and exit capacity. This includes consideration of the critical interlinkages across connections policy, network charges, and possible distortions caused by differences in arrangements at different voltage levels.

Background and context

The electricity system in GB is experiencing one of the most rapid changes since the markets were liberalised in the 1990s, driven by the need to decarbonise, step changes in technology, and the evolving expectations of customers. As demand and supply become more volatile and unpredictable, the strains on the networks, and the challenges for operators of those networks, increase. Significant investment is needed in new capacity, flexibility, systems, data and processes, and operating and business models will need to evolve. It is imperative that this investment is efficient, and delivers consumers safe, reliable and affordable electricity. Ultimately, in the future more electricity needs to be delivered to customers using relatively less network infrastructure.

Current arrangements for network access and charging were designed in a world of mainly centralised (and controllable) generation, fairly predictable uni-directional network flows and before the advent of smart metering. Where changes to the arrangements have occurred, these have generally been to accommodate more renewables on the transmission system, such as the Transmission Access Review programme and Project TransmiT, which led to changes in charging for transmission-connected generators. Current industry governance is struggling to keep up with the pace of change now being witnessed.

In November 2017, Ofgem issued a working paper titled *Reform of Network Access and Forward-looking Charges*[4] which set out the issues, potential building blocks for options for reform, and the plan to address the key regulatory gaps in this area, working in conjunction with industry.

In parallel, Ofgem launched the Charging Futures Forum (CFF) as a programme to coordinate significant charging reform, and consider a wide set of interrelated issues in a coordinated manner. Under the CFF, Ofgem has launched two Task Forces, involving industry participants, whose role is to consider issues and develop options for reform in two interrelated areas: Access; and Forward Looking Charges.

The CFF is also a forum for discussion of ongoing work under the Targeted Charging Review (TCR) Significant Code Review (SCR) which is mainly concerned with reforming arrangements for the

[4] https://www.ofgem.gov.uk/system/files/docs/2017/11/reform_of_electricity_network_access_and_forward-looking_charges_-_a_working_paper.pdf

appropriate recovery of the residual (non-forward looking) element of charges. Residual charges are outside of the scope of this work.

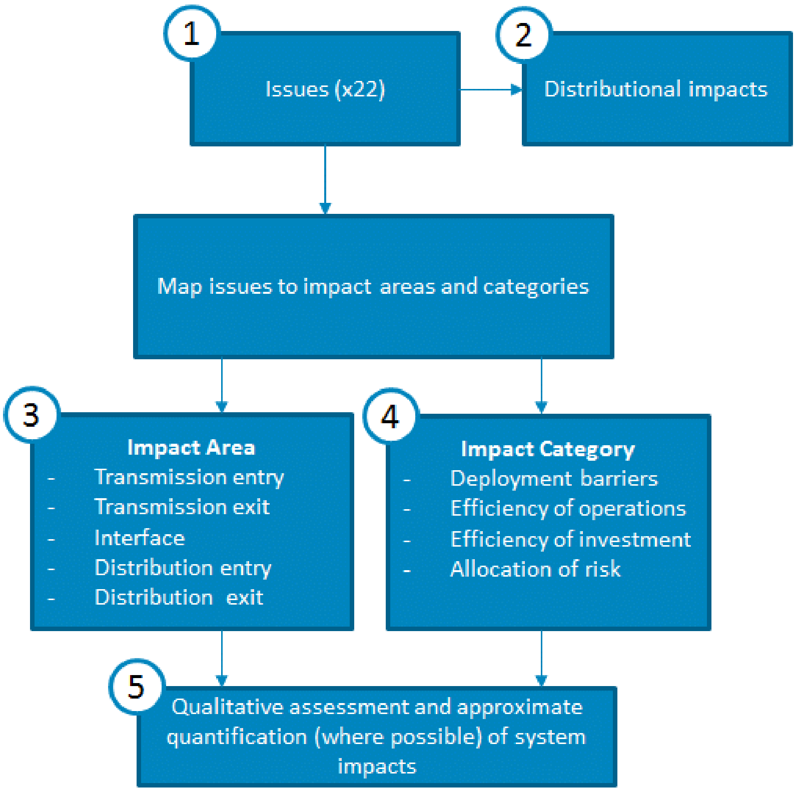
Our approach

In developing our assessments, we have set out a framework and process by which issues with the current arrangements are identified and their relative materiality assessed on a qualitative basis, supported by relevant quantitative metrics, where possible.

Our approach, summarised in Figure 1 was undertaken in the following stages:

1. Identifying a series of issues with the current arrangements (**Section 3**), starting with those identified in the Ofgem November 2017 working paper and supplementing with our views and those of the Task Forces
2. Assessing the distributional impact of these issues, namely how the issues affect different types of network user and therefore whether charges faced by different network users are reflective of the costs (or cost savings) they impose on the system (**Section 4** and **Appendix A**)
3. Mapping the issues to their wider system impacts: (**Section 5**)
    - **Transmission entry:** Impact associated with users of transmission entry (typically transmission connected generation and storage)
    - **Transmission exit:** Impact associated with users of transmission exit (typically demand)
    - **Distribution entry:** Impact associated with users of distribution entry (typically distribution connected generation and storage)
    - **Distribution exit:** Impact associated with users of distribution exit (typically demand)
    - **Interface:** Impact associated with issues between transmission and distribution
4. Assessing the materiality of the wider system impacts under the following categories:
    - **Deployment barriers:** The scale and length of delays to access (e.g. connection queues)
    - **Efficiency of operations:** The extent that the dispatch of existing generation and demand on the system is sub-optimal as a result of inefficient short term network access and charging signals
    - **Efficiency of investment:** The extent that network investment costs are greater than necessary as a result of inefficient long term network access and charging signals
    - **Allocation of risk:** The extent that there is inappropriate allocation of risk between network users and other parties, e.g. network owners, could lead to inefficient outcomes (e.g. stranding)
5. Combining the distributional and wider system wide impacts in order to draw conclusions on the most material issues, and therefore where policy changes might be focused (**Section 6**).

Figure 1 - Overall approach



Our qualitative assessment of the issues draws on a broad set of evidence, as described in the following sections. The quantitative assessments of materiality were developed from a combination of existing sources and evidence where available, supplemented and supported by our own analysis. Given the breadth of the issues under consideration, the quantification has been undertaken at a relatively high level. This is not intended as a full impact assessment at this stage. The quantification informs the qualitative assessment, and where quantitative metrics are less appropriate/reliable or more uncertain, we have relied less on these and more on the qualitative assessment. The methods, assumptions and sources are set out in Appendix B.

Through this process, we have engaged with the industry through the two Task Forces. Specifically:

- We presented our approach, initial thinking and initial issues list at the January Task Force meetings (24th and 25th January 2018), and received feedback from the Task Force members on the initial issues list and potential data sources.
- We presented our qualitative assessment of the wider impacts at the March Task Force meetings (20th and 21st March 2018), and received feedback from the Task Force members on the distributional and wider system impacts.

3 Issues with current arrangements

3.1 Introduction

In this section we set out the issues identified with the current network access and charging arrangements. We recommend that readers not familiar with network access and charging arrangements first review Ofgem's November 2017 working paper[5], in particular Chapter 3 on current arrangements, which was the starting point for the issues we have assessed.

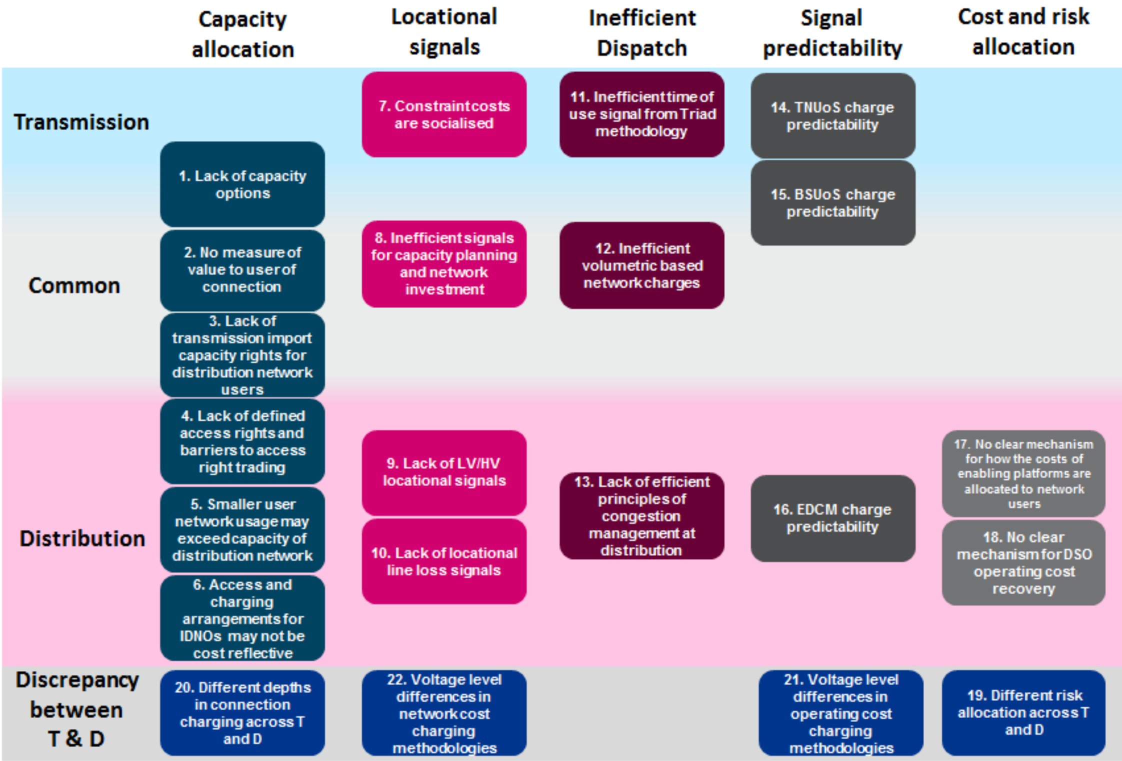
3.2 Issues identified

We have identified 22 potential issues with current arrangements, starting with those identified in the Ofgem November 2017 working paper and supplementing with our views and those of the Task Forces. These issues cover both access (connection) and forward looking (use of system) charges at all voltage levels (transmission and distribution), for all user types across both entry and exit capacity. The issues have been defined based on suggested or observable potential deficiencies in the current arrangements. The identification of an issue does not necessarily indicate a requirement for reform or a potential future solution.

Each issue, many of which are inter-linked, may impact on a number of different desirable features for the access and forward looking charging arrangements as set out by Ofgem in the November 2017 working paper. For convenience we have grouped the issues under different categories, although arguably some issues fall under more than one category (Figure 2).

[5] Reform of electricity network access and forward-looking charges: a working paper, Ofgem, November 2017

Figure 2 - Issues and categorisation



Capacity allocation

The first group of issues may result in the inefficient allocation of network capacity. This can arise due to a lack of an explicit definition of access rights, a lack of options for access rights, or the inability or lack of incentive to release or trade existing access rights.

These issues manifest in wider system impacts (Section 5) as barriers to deployment due to spare existing capacity being unavailable to new developments. These barriers prevent new, potentially more efficient and lower carbon generation from connecting to the network and can therefore result in higher generation costs and greater carbon emissions than necessary. In addition the inefficient allocation of network capacity, or the lack of capacity options, reduces the signal for future requirements for network investment, resulting in a lack of capacity being available for network users when and where they value it.

Table 1 - Capacity allocation issues

Issue	Issue Description
1. Lack of capacity options	A limited range of shorter term (within year) Transmission Entry Capacity (TEC) options are currently available, although these are not widely used. There are no seasonal products or other means to indicate demand for spare capacity outside of peak system usage from network users on both transmission and distribution networks.
2. No measure of value to user of connection	There are currently queues to connect to parts of the transmission and distribution networks (although this varies by location and between demand and generation). This process does not account for how parties in this queue may value use of the network differently relative to others in the area, nor does it account for the possibility that existing 'capacity holders' may have a price at which they would release capacity back to the connections queue.
3. Lack of transmission import capacity rights for distribution network users	There is currently no method for allocating entry capacity to the transmission system for distribution connected users. This creates a difference between transmission access rights for transmission connected generation, which are based on their TEC (with consequent TNUoS charges), and smaller embedded generation (EG) which have an implied access right to the transmission network. The lack of a formal definition of transmission access rights for smaller EG may result in inefficient network reinforcement at transmission as reinforcement decisions do not fully reflect EG transmission access requirements.
4. Lack of defined access rights and barriers to access right trading	The value of capacity access is not signalled on a locational basis. Where users have TEC, that capacity is defined by reference to the transmission system as a whole rather than more locationally[6], making TEC difficult to trade as a product. At present there is limited scope to exchange TEC, and little use has been made of provisions to do so (there is no secondary market). Sharing of TEC is unlikely other than for generators within a single station. There is a lack of capacity trading available on distribution networks, where there is no exchange mechanism.
5. Smaller user network usage may exceed capacity of distribution network	Smaller users currently have no capacity limits on their demand usage, beyond the limit of the typical 100 amp fuse, equivalent to 23kW. The distribution system is planned assuming a high degree of load diversification among domestic and smaller users. This means that the physical capacity a particular small user can use is higher in aggregate than the capacity to which the distribution system is planned. If those assumptions break down, for example, due to clustered electric vehicle (EV) uptake and coincident charging behaviours (including a significant proportion of home charging), then there may be insufficient capacity, requiring network reinforcement. Under the Common Distribution Charging Methodology (CDCM), which sets smaller user network charges, charges do not have a locational element (within an individual DNO area) and therefore there is no ability to identify and charge the costs of reinforcement back to the users contributing to the reinforcement requirement. Neither is there a method to allocate the available capacity to users ahead of reinforcement.
6. Access and charging arrangements for IDNOs may not be cost reflective	Charging arrangements for Independent Distribution Network Operators (IDNOs) are typically based on the DNO equivalent charges. Rights for IDNOs to export onto DNO networks are defined in Bilateral Connection Agreements (BCAs) with defined Maximum Import and Maximum Export Capacity. Issues may arise when the IDNO provides services to the DNO, or additional reinforcement is required on IDNO network.

[6] Users with TEC are charged TNUoS (which has a locational element) based on that TEC. However TEC itself as an access product does not have a locational price.

Locational signals

This group of issues is related to a lack of clear locational signals, either through charges which reflect the cost of a user's impact on the network or signal the value of network access in different parts of the network to the network operator.

These issues typically manifest in wider system impacts as barriers to deployment due to network capacity being unavailable where it is most valued and charges not reflecting the cost of a user locating, and operating, in a specific location. These barriers may prevent new, potentially more efficient, generation (and storage) from connecting to the network in areas where capacity is currently limited but could be expanded, or conversely may result in network operators carrying out inefficient reinforcement when generators could have connected elsewhere, resulting in wider users potentially facing excessive charges.

Table 2 - Locational signal issues

Issue	Issue Description
7. Constraint costs are socialised	The socialisation of constraint costs through Balancing Services Use of System (BSUoS) Charges means that costs are not targeted to those users that are imposing the costs on the system. This issue is more pronounced as a result of the Connect & Manage policy for transmission connections.
8. Inefficient signals for capacity planning and network investment	Connecting customers are strongly reliant on network operators' planning and processes to bring forward new capacity efficiently, given that he alternative approach of network users directly funding new network capacity expansion would lead to very challenging coordination issues and therefore high transaction costs. However, currently network operators may not have visibility of value that groups of users would place on additional capacity, and a lack of appropriate user commitment and/or incentives on network operators to undertake investment ahead of firm commitments from users means that capacity may not be available when customers need it. In addition, there is currently no equivalent to Balancing Mechanism (BM) constraint costs that could be used to inform the needs case for reinforcement at distribution level (equivalent to Network Options Assessments (NOAs) at transmission level). While transmission constraint costs can provide a good instantaneous signal of where reinforcement might be needed, there is no market that signals forward requirements, therefore relying on the System Operator (SO) and DNO's forecasting which may be based on imperfect information on future users' capacity requirements.
9. Lack of LV/HV locational signals	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 in terms of available network capacity, or indicate when a specific area is congested. The costing model which underpins the CDCM is based on a demand only network, which assumes that all units flow from Grid Supply Point (GSP) to demand. This creates an enduring assumption that EG is always of value and only demand drives costs.

Issue	Issue Description
10. Lack of locational line loss signals	A lack of a cost reflective resistive line loss signals (within DNO areas) could distort signals and lead to inefficient investment and operation. Line losses are currently socialised through DUoS amongst wider customers. In practice, line losses vary across the distribution network, dependant on network topology and asset utilisation.

Inefficient dispatch

These issues result in the inefficient operation of the system due to inadequate time of use signals, lack of dynamic capacity signals and distorted short term locational signals. They are a consequence of signals which fail to reflect the impact of the user on the system or fail to provide a dynamic signal of a user's value of system access.

These issues manifest in wider system impacts as operational inefficiencies due to the inefficient dispatch of generation, storage and demand side response.

Table 3 - Inefficient dispatch issues

Issue	Issue Description
11. Inefficient time of use signal from Triad methodology	The use of Triads[7] to determine TNUoS charges for customers with half-hour metering creates an imprecise signal due to the uncertain timing of Triad periods, which are difficult to forecast and hence respond to. This does not directly reflect costs on the system which are related to peak utilisation of assets.
12. Inefficient volumetric based network charges	In general, flat rate volumetric charges (e.g. DUoS for small consumers) do not closely reflect actual drivers of network investment/operation, which largely depend on peak utilisation of assets. Where Time of Use signals exist, the timing is inconsistent across different charges: TNUoS for non-half hourly (NHH), Extra High Voltage Distribution Charging Methodology (EDCM) and CDCM. This can only be justified if the timing of cost drivers is similarly different for each group of customers.
13. Lack of efficient principles of congestion management at distribution	Where flexible connections have been implemented at distribution level, curtailment is not occurring on an economically efficient basis. For example, under Last In First Off (LIFO), it is possible for the user with the highest opportunity cost of curtailment to be curtailed first. Estimates of curtailment are provided before connection, though actual levels will be variable based on network conditions and location. Curtailment which is uncompensated may be overused (compared to investing in network capacity) because it is not being valued. Further, there has been limited standardisation of approaches across different DNO schemes and also between the SO and DNOs, and there is no mechanism or incentive for existing capacity on traditional connection agreements to participate to ensure most economically efficient curtailment.

Signal Predictability

These issues arise due to the lack of predictability in network charges. A lack of predictability in a network charge may result in networks users being unable to change their behaviour in order to

[7] The three half-hour settlement periods with highest system demand between November and February, separated by at least ten clear days.

reduce their exposure to it, or require network users to make provisions (e.g. holding greater risk capital than necessary) in order cover charge volatility.

The inefficient allocation of risk may ultimately result in inefficient investment in the wider energy system.

Table 4 – Signal predictability issues

Issue	Issue Description
14. TNUoS charge predictability	Customers can be faced with increasing locational TNUoS charges which are unpredictable as they are dependent on the actions of other network users (e.g. retiring plant, new generation connections). These charges are also hard to forecast due to complexity of the Tariff and Transport methodology and model (which includes detailed load flow modelling) which is used to set TNUoS tariffs.
15. BSUoS charge predictability	BSUoS charges are difficult to predict in advance due to their volatility and the fact that they are set ex-post, meaning they may not be providing an efficient signal (particularly given the socialisation of costs). Users who cannot act to avoid BSUoS charges will face higher charges, whilst these higher charges do not correlate with the cost impact of the users on the system.
16. EDCM charge predictability	EDCM demand charges include a strong, locational element which is distinct for every substation in the network. EDCM charges therefore require a bespoke assessment for each user depending on actual prevailing network conditions, which is variable. These charges are unpredictable due to their complexity and can be quite volatile, making it difficult for users to respond to.

Cost allocation

These issues arise due to the disproportionate allocation of certain network costs between different network users. As DNOs continue to develop their operational capabilities during their transition to becoming Distribution System Operators (DSOs[8]) these issues will become increasingly important.

Table 5 – Cost and risk allocation issues

Issue	Issue Description
17. No clear mechanism for how the costs of enabling platforms are allocated to network users	Where enabling platforms, such as new control systems required to enable flexible connections, are required it is not clear which sets of network users these should be recovered from, or from all network users.
18. No clear mechanism for DSO operating cost recovery	Currently all DSO operating costs must be recovered through DUoS charging whilst SO costs are recovered through BSUoS (and not TNUoS). This creates different incentives for the DSO relative to the SO in decision making around operational solutions, which may not lead to the most efficient outcomes.

[8] Open Networks Project: DNO to DSO, Energy Networks Association

Issue	Issue Description
19. Different risk allocation across transmission and distribution	**Asset stranding risk** Shallower connection charging on the transmission system means that wider users (rather than connectees) are exposed to any stranding risk for wider transmission assets. Post commissioning, transmission users are exposed to a two year commitment to wider TNUoS. Deeper connections on distribution networks means more upfront cost for connectees (since distribution connection charges are typically paid in advance) and implicitly greater user commitment, although there is no ongoing commitment to DUoS charges. **Curtailment risk** There is a greater exposure to curtailment risk for generators connected to the distribution system. Connections to the transmission system are financially firm whereas flexible connections to the distribution network are uncompensated with no certainty of curtailment levels.

Discrepancy in charging arrangements across transmission and distribution

These issues arise due to the discrepancy in charges that users face between the transmission and distribution systems. The discrepancies occur across network, operating and connection charges.

These issues manifest in wider system impacts through inefficient investment as differences in charges distort the investment case for connection between transmission and distribution. This can subsequently result in excessive system costs, as well as distorting the dispatch of generation across the interface. This distortion in investment decisions also increases connection queues at certain voltage levels, exacerbating barriers to deployment of generation and demand. Distortions in dispatch may occur where there are differences in output-based (volumetric) charges.

Table 6 - Discrepancy in charging arrangements issues

Issue	Issue Description
20. Different depths in connection charging across T and D	Distribution connections are liable for reinforcement costs, up to one voltage level above that required to accommodate the connection, but can locate to avoid these costs, whereas transmission generation connection charges only cover connection assets. Furthermore, GSP reinforcement costs triggered by a distribution connection are not subject to the voltage level rule, and therefore the whole cost falls to the connecting party.

Issue	Issue Description
21. Voltage level differences in network cost charging methodologies	There are a number of differences in the Transmission Network Use of System Charges (TNUoS) charges faced by transmission connected generation and distribution connected generation. First, smaller EG does not pay TNUoS in areas of negative demand TNUoS, but does receive the credit in areas of positive demand TNUoS. This is because the Embedded Export Tariff[9] is floored at 0, meaning smaller EG do not face costs for generating in a generation dominated area. Second, the Embedded Export Tariff (EET) benefit is calculated on a different basis compared to transmission connected TNUoS charges, through Triad periods for smaller EG rather than entry capacity. Larger differences exist in the case of onsite generation, which is treated as negative demand. In addition, there are also differing methodologies behind the calculation of locational charges. For example, charges set through EDCM may give sharper locational signals than TNUoS in areas with little spare capacity. The former is based on an actual bespoke assessment of costs for new capacity, which takes account of likelihood of reinforcement being required. The latter is based on the incremental long run costs[10], which assume incremental expansion of the network and hence do not reflect spare capacity.
22. Voltage level differences in operating cost charging methodologies	Smaller EG do not face BSUoS charges and receive a benefit for avoiding Supplier BSUoS charges, whereas transmission connected generation (TG) and larger EG face BSUoS charges on their full metered output.

[9] The Embedded Export Tariff is a TNUoS credit paid to smaller EG, introduced in April 2018 as a consequence of CMP 264/265. The residual element in the EET is being phased out over three years, after which the EET will contain forward looking benefits only

[10] TNUoS charges are composed of a wider and a local component. TNUoS wider charges are based on incremental expansion costs, whereas local circuit charges (for example for offshore wind local circuits) use actual costs as an input.

4 Distributional impacts of the issues

4.1 Introduction

A distributional impact relates to how different parties are affected by an issue, in this case different types of network user and those in different locations. In general, because allowed revenue is recovered in full from network users, a reduction in charges for one set of users results in an increase for another set of users. Distributional issues occur where charges are not reflective of the costs (or cost savings) that different types of user impose on the network.

For each issue, we have assigned a Red/Amber/Green (RAG) rating for its distributional impact based on our assessment of materiality and the strength of links to other impacts. Below, we describe the most material issues from a distributional impact, and summarise the assessment for all remaining issues.

4.2 High materiality issues

The issues that have been ranked High materiality from a distributional perspective are described in this section.

Issue 5. Smaller user network usage may exceed capacity of distribution network

Smaller users do not face a capacity charge linked to their peak demand. Under HHS tariffs, customers may face a distribution time-of-use (ToU) charge but with a wide red band and no locational element (other than variation between DNO regions). Therefore, a small user with a high peak demand due to LCT (EV or heat pump) uptake will not face a cost reflective Use of System charge. As a consequence, any reinforcement costs triggered by high LCT penetration will then be socialised to wider customers.

Under the current domestic unrestricted tariff rate, we estimate that a customer with a standard domestic 3.5kW EV charging point will double its contribution to peak demand, and yet its DUoS charge would increase by only around 50% under current arrangements. This assumes an increase in after diversity maximum demand (ADMD) for EV users of around 1kW as found in the My Electric Avenue project[11], the charging profile and technical specifications of a standard EV, and the average daily vehicle distance travelled in GB. Impacts could be less significant if a greater proportion of EV charging is at out of home fast charging stations, or with increased transportation-as-a-service business models (relying on shared and/or autonomous vehicles), although issues related to a lack of locational signals will still apply to these charging stations.

[11] My Electric Avenue project, http://myelectricavenue.info/, EA Technology on behalf of Scottish and Southern Energy Networks (SSEN)

Issue 7. Constraint costs are socialised

Some transmission-connected generators cause high constraint costs but pay roughly the same BSUoS charges as other network customers who cause no constraint costs or alleviate constraints. Locational TNUoS charges do not reflect constraint costs directly, since these are based on incremental expansion costs and do not consider spare capacity on the network. Hence a low generation TNUoS charge is possible in a constrained area with excess generation, and vice versa.

Constraint costs are most prevalent in areas where a high capacity of generation has connected under connect and manage (C&M). The annual constraint costs attributable to capacity connected under C&M as of September 2015 equated to around £64 per kW of C&M capacity[12], which far exceeds the BSUoS charges that those generators face which are around £6/kW (assuming a wind farm with a typical load factor). These constraint costs are socialised amongst, and result in higher costs for, wider customers.

Issue 20. Different depths in connection charging across T and D

Distribution network users may face relatively higher connection costs when requesting connection in their preferred location, as they are liable for reinforcement costs that are required to accommodate the connection up to one voltage level above, compared to transmission network connections. However, evidence to date shows that users are infrequently accepting connection offers when wider reinforcement is required, with just 5% of distribution connections triggering network reinforcement between 2010 and 2013[13], and instead connecting in an area with existing spare capacity, or accepting a flexible connection.

While one-off connection costs to a desired location on the transmission network may average around £20/kW[14], if reinforcement is triggered on connection to the distribution network the corresponding connection charge is likely to be greater than £100/kW.

In addition, distribution network users that trigger reinforcement of GSP assets face the associated reinforcement cost regardless of voltage level of connection.

Issue 21. Voltage level differences in network cost charging methodologies

Smaller EG benefits from DUoS charges and TNUoS Embedded Export Tariffs whereas transmission generation and larger EG contributes to TNUoS, resulting in distributional effects between users at different voltages, with TG typically losing out to EG.

Smaller EG does not face TNUoS charges even if located behind an exporting GSP, which is a charge that can vary between £-6/kW to £30/kW (not including the residual element). A more in-depth comparison between voltage level charging differences can be found in Table 18.

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[12] Monitoring the 'Connect and Manage' electricity grid access regime, Sixth report from Ofgem, 14 December 2015. Calculated from the total annual constraint costs attributable to C&M between September 2014 and September 2015 divided by the total capacity of large generation connected under C&M

[13] A guide to electricity distribution connections policy, Ofgem, April 2014

[14] Open Networks Project: Charging Scenarios report, Energy Networks Association, August 2017

4.3 Distributional impacts summary

The assessment for all issues is set out below, with brief comments on the Medium materiality issues. Not all issues have a direct distributional impact (but rather contribute to wider system impacts). Where this is the case, these are not rated (grey). Detailed assessment of all issues is included in Appendix A.

Capacity allocation

Issue 2 (No measure of value to user of connection) is rated Medium materiality because on the distribution network a significant volume of existing capacity could be released to the current queue if it were fully valued. A UKPN study[15] showed that only 45% of EG fully utilise their connection capacity in a given year, where full utilisation is defined as annual peak generation greater than 75% of the rated connection capacity (as per 12.11C National terms of Connection). This implies that there exists a large volume of unutilised existing capacity which could be allocated to new connections, estimated as over 1 GW on UKPN's networks alone.

Issues 3 and 4 do not have a clearly assessable distributional impact, but are drivers of wider system impacts of deployment barriers and efficiency of investment.

Table 7 - Capacity allocation issue distributional impacts

Issue	Assessment
1. Lack of capacity options	**Low**
2. No measure of value to user of connection	**Medium**
3. Lack of transmission import capacity rights for distribution network users	**N/A**
4. Lack of defined access rights and barriers to access right trading	**N/A**
5. Smaller user network usage may exceed capacity of distribution network	**High**
6. Access and charging arrangements for IDNOs may not be cost reflective	**Low**

Locational signals

Issue 9 (The lack of LV/HV locational signals) is Medium materiality because CDCM charges are not cost reflective as location is not accounted for within a DNO area. Hence users who may impose higher costs on the network are charged the same as those in areas with lower costs and therefore receive a relative benefit. These costs may be incurred via future reinforcement to the network, the costs of which will vary significantly with location.

Under the CDCM, generators are automatically credited even in generation dominated areas. These Generator credits can result in an annual net DUoS benefit of around £20/kW (locational and residual elements) and yet they could be adding to costs, leading to other users paying more. Total generation credits under CDCM are £61.6m annually[16].

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[15] Distributed Generation Customer Forum, UKPN, 25th February 2016

[16] Total credits projected to be paid to generation, sourced from DNO CDCM models for 2018/19

Table 8 - Distributional impacts of locational signal issues

Issue	Assessment
7. Constraint costs are socialised	High
8. Inefficient signals for capacity planning and network investment	N/A
9. Lack of LV/HV locational signals	Medium
10. Lack of locational line loss signals	Low

Inefficient dispatch

Inefficient dispatch signals are more significant from Triad than from volumetric based Red/Amber/Green DUoS network charges. Through the incentive for Triad chasing by smaller EG (in order to achieve the EET), TNUoS customers are in effect helping to fund savings in wholesale` and Capacity Market costs by reducing system peak load. Although there is commonality in the user groups there will still be some distortive effects since the charge base differs for TNUoS, wholesale electricity and Capacity Market charges. In addition, transmission generators see a reduced level of demand due to Triad chasing by smaller EG, resulting in potentially foregone revenues.

Volumetric charges do not reflect the network cost impact of most users on a temporal or locational basis, which largely depend on peak utilisation of assets. Small consumers with a high peak to average demand ratio do not currently fully face the costs of their impact on the system through DUoS charges under unrestricted tariffs. Where there are banded volume based charges based on ex-ante peaks these may or may not be cost reflective.

The lack of efficient principles of congestion management at distribution is potentially significant given the future expected growth in flexible connections.

Table 9 - Distributional impacts of inefficient dispatch issues

Issue	Assessment
11. Inefficient time of use signal from Triad methodology	Medium
12. Inefficient volumetric based network charges	Low
13. Lack of efficient principles of congestion management at distribution	Medium

Signal predictability

The distributional impact of the issues regarding charge predictability is between parties who pay the charge and those who do not, as captured below under issues on discrepancy of charging.

Table 10 - Distributional impacts of signal predictability issues

Issue	Assessment
14. TNUoS charge predictability	N/A
15. BSUoS charge predictability	N/A
16. EDCM charge predictability	N/A

Cost and risk allocation

These issues are low materiality from a distributional perspective mainly due to the relatively low scale of the costs involved. The issue of risk allocation across transmission and distribution is captured in Section 5.6.4 on Interface Allocation of Risk, where this is a Medium wider system impact.

Table 11 - Distributional impacts of cost allocation issues

Issue	Assessment
17. No clear mechanism for how the costs of enabling platforms are allocated to network users	**Low**
18. No clear mechanism for DSO operating cost recovery	**Low**
19. Different risk allocation across T and D	**N/A**

Discrepancy in charging arrangements across transmission and distribution

The voltage level difference in operating cost methodologies (targeting of constraint costs) has a smaller impact than differences in network cost charging methodologies (TNUoS, DUoS) due to the scale of the charges involved.

Table 12 - Distributional impacts of interface charge discrepancy issues

Issue	Assessment
20. Different depths in connection charging across T and D	**High**
21. Voltage level differences in network cost charging methodologies	**High**
22. Voltage level differences in operating cost charging methodologies	**Medium**

5 Wider system impacts

5.1 Introduction

In this section, we set out our assessment of the wider system impacts areas, across:

- **Transmission entry:** Impact associated with users of transmission entry (typically generation and storage)
- **Transmission exit:** Impact associated with users of transmission exit (typically demand[17])
- **Distribution entry:** Impact associated with users of distribution entry (typically smaller scale generation and storage)
- **Distribution exit:** Impact associated with users of distribution exit (typically demand[18])
- **Interface:** Impact associated with issues between transmission and distribution, which can affect either systems, or both.

The wider system impacts are qualitatively assessed under the four categories of **Deployment barriers**, **Efficiency of operations**, **Efficiency of investment**, and **Allocation of risk**, supported by quantification, where possible:

- **Deployment barriers:** Barriers to deployment impact on the ability of users to connect the assets they want, where and when they want. This results in queues for both demand and generation connections, and can deter users before connection application stage (i.e. they never join the queue). Of relevant is evidence of existing queues, on distribution and transmission networks, as well as the potential for delays in connection in the future.
- **Efficiency of operations:** Inefficient operation or dispatch of users (in response to inappropriate charging signals) and the resulting inefficient operation of the system raises overall costs. This category has been narrowly defined to inefficient operation of the current system to avoid an overlap with efficiency of investment impacts. Evidence of existing inefficient system operation is used to assess materiality under this category.
- **Efficiency of investment**: Covers inefficient investment in network reinforcement (to maintain security standards) as a result of, for example, user decisions on asset type and location due to inappropriate signals. Estimates of the potential for inefficient investment under current arrangements are produced using the National Grid Future Energy Scenarios (FES) to provide a possible range of deployment scenarios for generation, demand and LCTs.
- **Allocation of risk:** This area covers the impacts of distortions in the allocation of risk including: the risk of stranding of network investment, i.e. which users are liable for underutilisation of network assets; curtailment risk i.e. how is the uncertainty of curtailment passed onto users with flexible connections; and, the lack of predictability of

[17] Including import of electricity for storage facilities
[18] Including import of electricity for storage facilities

charges i.e. the costs imposed on users associated with charge volatility that they cannot manage.

For each area, the impact is assigned a Red/Amber/Green (RAG) rating. In Table 13 we set out the basis for each rating including indicative quantitative metrics.

Table 13 - Qualitative assessment and quantitative metrics

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

In the following sections, we describe the assessment for each wider system impact in turn.

5.2 Transmission entry

In the area of transmission entry, we have considered issues and impacts relating to the access for transmission connected generators and storage and the development of the network to meet their requirements.

One of the major features of the transmission access regime is Connect & Manage, under which generation (and storage) can connect to the transmission system once enabling works are complete, ahead of the completion of any wider works. The impact of connecting generation ahead of wider reinforcement is an increase in constraint costs as a result of operationally managing the congestion via the Balancing Mechanism (BM) and forward contracts. By September 2015, Connect & Manage had led to the accelerated connection of 1.9 GW of large project generation capacity. Constraint management costs of £122mn were attributable to this capacity in the year preceding, from September 2014 to September 2015[19]. This constraint cost is socialised across TG, larger EG and demand and recovered via BSUoS.

The impacts are summarised in Table 14, and described in the following sections.

[19] Monitoring the 'Connect and Manage' electricity grid access regime, Sixth report from Ofgem, 14 December 2015

Table 14 - Transmission entry wider system impacts

	Impact description	Rating
Deployment barriers	A lack of network capacity (typically associated with Enabling Works) is preventing or delaying generation projects from connecting to the transmission network. Evidence suggests that the queue under Connection & Manage regime is small (relative to distribution entry).	Medium
Efficiency of operations	Transmission entry users are not fully exposed to their direct impact on constraints on the transmission network. Resolution of constraints via dispatch in the BM is likely to be close to being as efficient from a system perspective as self-curtailment in response to price signals (notwithstanding the distributional impacts from socialising constraint costs via BSUoS).	Low
Efficiency of investment	New generation connecting to the transmission network faces signals which are related to incremental expansion costs but do not reflect the short term cost impact of increased constraint management costs which may occur (particularly if accelerated under the Connect & Manage regime) and which may require reinforcement in the longer term.	Medium
Allocation of risk	Stranding risk: Early disconnection of generators could lead to stranding of investments that were made to accommodate those generators. There is little evidence of asset stranding as a result of generation developments disconnecting early, however, in future there is greater potential due to reductions in transmission system demand or displacement of thermal generation by renewables which may result in generators closing early. Predictability of charges: The volatility of TNUoS and BSUoS charges results in higher risk for users, resulting in a risk premium which may ultimately be passed through to consumers via wholesale power prices or Capacity Market clearing prices.	Medium

5.2.1 Deployment barriers

Despite the implementation of Connect & Manage, delays for connection at transmission remain, mainly due to the need for Enabling Works to be completed before connection.

Data for the connection queue at transmission level has been provided by National Grid. There is currently 1.5 GW of renewable generation capacity and 0.1 GW of non-renewable capacity that is facing an unwanted delay to connection, with an average delay of 13 months [20] (although not all capacity in the queue will necessarily be developed). The main limitation with this metric is that it is a current snapshot rather than a forward looking forecast of the potential queue under current arrangements, and does not include developments that do not apply due to the known queue. Elsewhere, we have used the National Grid Future Energy Scenarios (FES) to provide forward looking views of deployment. However, these scenarios cannot themselves provide forecasts of connection queues, only the amount of capacity expected to connect at transmission.

[20] Timely connections reports, National Grid

5.2.2 Efficiency of operations

The users creating constraint costs are not facing direct signals related to this cost, and hence do not respond in self-dispatch. However, actions in the BM to resolve constraints are likely to lead to an outcome that is efficient in terms of generation dispatch, particularly with the Transmission Constraint Licence Condition in place which obliges BM participants to make cost reflective bids and offers.

Although constraint costs are significant (between £190mn to £410mn per year in the period between 2011 and 2017), this is largely a distributional issue (see Issue 7) as to whether they are targeted at the right parties.

5.2.3 Efficiency of investment

New generation connecting to the transmission network faces signals which are related to average expansion costs but do not reflect the short term cost impact of constraints.

We estimate the cost of network reinforcement required to accommodate increasing Scottish wind capacity by 2040 to be in the range from £980mn to £2,300mn, based on National Grid's FES capacity projections. This figure assumes an incremental expansion cost of £20/kW/year (the average Scottish TNUoS intermittent tariff) and the proportion of new wind capacity located in Scotland in the same ratio as current levels. It is likely that TNUoS more or less reflects these costs over the long term. However, in the short term, the constraint management costs attributable to capacity connected under C&M before wider works are completed are socialised amongst wider customers through BSUoS charges. These constraint management costs attributable to capacity connected under C&M are estimated to average, based on historical constraint costs since 2011 and National Grid cost projections out to 2024, around £64mn per annum. If capacity connecting under C&M continued at broadly the same rate since C&M was introduced then the additional constraint costs would be around £1,000mn on a NPV to 2040 basis. However, the commissioning of approved network reinforcements (including the Western HVDC link and the Caithness-Moray cable) will reduce constraint costs, in effect converting these operational costs into investment costs. With a continuation of C&M, it is likely that constraint costs could begin to rise again, and network reinforcement would take place as a result.

Overall costs could be higher than if users connected where there is spare capacity. However, there may be strong drivers for connecting in locations with limited spare capacity, including, for example, higher load factors for renewables. Although the potential inefficiencies are not clear cut, the potential large magnitude of cost warrants a Medium materiality rating.

5.2.4 Allocation of risk

We consider two areas in which the allocation of risk between parties may be inefficient. First, we look at a form of stranding risk related to underutilisation of transmission network infrastructure. Second, we consider the impact of unpredictability of charges on users.

Stranding risk

Transmission asset stranding can occur when investments are made with the expectation of usage which does not then materialise. This could occur due to planned generation not being developed (pre-commissioning stranding) or generation closures (post-commissioning stranding).

In 2011, CMP192[21] considered user commitment for generation in both the pre- and post-commissioning phases. Whilst the cancellation of a pre-commissioning generator could affect attributable[22] and wider transmission system investment decisions, the closure of a post-commissioning generator will only affect new wider transmission system investment decisions. CMP192 focussed on information to assist transmission companies to efficiently manage ongoing new investments on the transmission system, and hence avoid under-utilisation of assets.

National Grid found no evidence, as of 2011, of actual electricity transmission assets in GB being stranded, i.e. transmission assets that have not been allowed to form part of the regulated asset base (RAB) and for which there is no revenue recovery through the TNUoS charges. The CMP192 workgroup considered the level of risk of stranding to be small, estimated conservatively at £35m/yr for generation users (using assumptions on the amount of wider investment per year).

Regarding post-commissioning, CMP192 introduced a user commitment period of 2 years (i.e. liability for TNUoS for 2 years after giving notice). Therefore, the stranded cost of wider transmission assets developed for generators which then relinquish their TEC would be borne by all TNUoS users (via the residual) after this 2 year period of commitment. Ofgem's decision considered that there was not a clear case to increase post-commissioning user commitment to four years (as in the original proposal). Attributable assets carry no liability, however, and to the extent that existing sites are not reused these costs will be borne by consumers.

Clearly, the GB power system has changed significantly since 2011, with the growth in EG and transmission connected renewables, and a rapid rate of closures of existing coal stations and CCGTs in particular. It may well be the case that certain elements of the wider network are less well utilised than in the past, but there is no part of the wider system which has been specifically stranded as far as we aware (since once commissioned, generators tend not to close early). Many investments have taken place to address boundaries which are non-compliant with the SQSS as a result of generation connecting under C&M, and hence the need for network reinforcement is clearly demonstrable.

The FES show diverging pathways for transmission connected capacity. For example, in Steady State in 2025, 72 GW of capacity is transmission connected vs. 80 GW in the 2 Degrees scenario, which is

[21] https://www.nationalgrid.com/sites/default/files/documents/CMP192%20final%20CUSC%20Modification%20Report%20%201.0.pdf

[22] Attributable works are those works in a construction agreement that directly relate to a generator being connected to the transmission network. This includes the works up to and including those at an existing Main Integrated Transmission System (MITS). They are distinct from Enabling Works as defined under Connect & Manage. In some cases it is likely that the Enabling Works will be the same as the Attributable Works. However, in some circumstances (e.g. long radial parts of the network), Enabling Works may be required to be greater than the works necessary to connect to the MITS. In other circumstances where there is sufficient diversity of operations, it is possible that Enabling Works will be less than the works necessary to connect to the MITS, and therefore less than the Attributable Works.

driven by changes in new build as well as closures. This suggests the risk of stranding is higher than historically, although actual outcomes will depend on the location and type of new build versus closures. With the Capacity Market auction taking place four years ahead of delivery, most generators have a four year view of their commitment and hence are better placed to manage the risks of commitment.

Overall this warrants a Medium materiality rating, given the potential for future stranded asset investment. In Section 5.6.4 we consider the impact of the difference in stranding risk allocation between transmission and distribution.

Predictability of charges

Users are exposed to charges which suffer from a lack of predictability, and hence may place inappropriate levels of risk on users who are not best placed to manage them. For TNUoS, this takes the form of the uncertainty in the annual change in TNUoS. We restrict the discussion to locational TNUoS, since residuals fall in the scope of the TCR.

The quantification of the impact of the unpredictability of TNUoS charges has been assessed based on the theoretical risk capital that users would have to hold to cover the risk of locational TNUoS being higher than expected. Based on the potential change over a 5 year period, we estimate the potential variation in TNUoS to be around £3/kW/yr. If this is held as risk capital (at an assumed 8% WACC) this equates to £0.24/kW/yr. Assuming that all parties bid this into the Capacity Market as an additional risk premium, the impact is of the order of £12mn annually.

If another party (such as the SO) were to hold this risk then it is possible that there would be associated costs, which we have not attempted to quantify.

BSUoS charges vary on a half hourly basis (calculated ex-post), and in recent years have shown an increase in the distribution of the half hourly charge, with little to no diurnal or seasonal, or other predictable, shape. When generators sell electricity, or suppliers set prices for their customers, an assumption of the BSUoS charge has to be made since is this only known ex-post.

Modification CMP250 is considering the potential for fixing BSUoS on an annual basis. The majority of the CMP250 Workgroup[23] considered BSUoS on a half hourly basis to be essentially unforecastable. The Workgroup developed risk premia estimates, for different generation and demand types. For example, if a generator selling peak electricity in 2014/15 wanted to ensure that it avoided the risk of losses in 70% (P70) of the trading period, the Workgroup calculated that it would need to apply a premium of £0.21/MWh to the outturn average BSUoS in the peak trading period.

The overall analysis suggests that if market participants were to reduce their risk appetite by 20 percentage points to P70, the premium above the average BSUoS outturn would need to increase to somewhere between £0.13/MWh and £0.42/MWh. Applying this risk mitigation strategy would result in an over recovery of BSUoS costs from consumers of somewhere between £81mn and £201mn annually (across generators and suppliers). The CMP250 Final Modification Report does not

[23] CMP250: Final CUSC Modification Report, National Grid, February 2018

specify whether this over-recovery would endure in future years, not does it take a view on whether P70 or some other strategy would be appropriate.

Our estimate of BSUoS risk takes an alternative approach. We consider the maximum monthly deviation in historic BSUoS (2014-2017) from the average monthly BSUoS. This is £1.35/MWh, which suggests that risk capital of £0.06/kW/yr would need to be held, equating to £3m/yr for all generation.

We believe that our estimate is more appropriate than the CMP250 Workgroup figure attributable to generation (half of the total: £40mn to £100mn) since we assume that there is no long term over-recovery of BSUoS, but rather only a holding of capital to manage the risk due to half hourly variations, whereas the CMP250 Workgroup assumes that generator and suppliers over-recover on average.

Our estimates suggest that TNUoS charge predictability is a more material issue than BSUoS charge predictability.

5.2.5 Contributing issues

The transmission entry related issues which contribute to each wider system impact are set out in Table 15, including an assessment of the level of contribution (High/Medium/Low).

Table 15 - Transmission entry wider system impacts: contributing issues

Wider system impact	Linked issues	Contribution Level
Deployment barriers	1. Lack of capacity options	Medium
	2. No measure of value to user of connection	High
	4. Lack of defined access rights and barriers to access right trading	Medium
	8. Inefficient signals for capacity planning and network investment	Medium
Efficiency of Operations	7. Constraint costs are socialised	Medium
	8. Inefficient signals for capacity planning and network investment	Medium
Efficiency of Investment	7. Constraint costs are socialised	Medium
	8. Inefficient signals for capacity planning and network investment	Medium
Allocation of Risk	7. Constraint costs are socialised	Medium
	14. TNUoS charge predictability	Medium
	15. BSUoS charge predictability	Low

5.3 Transmission exit

Relative to transmission entry, the issues with regards to transmission exit (summarised in Table 16) are more limited and are all assessed as Low materiality.

Table 16 - Transmission exit wider system impacts

	Impact description	Rating
Deployment barriers	Network constraints may prevent demand from connecting. However, this is not perceived to be a major issue, based on NG connection queue data.	Low
Efficiency of operations	Users are not exposed to the constraint costs that they impose on the transmission network. Demand is not responding to signals of limited locational capacity as it is not typically participating in the BM and hence there is (limited) potential for more efficient dispatch if demand participation was encouraged.	Low
Efficiency of investment	Inefficient investment for transmission exit could occur, although we are not aware of evidence of this being an issue.	Low
Allocation of risk	Predictability of charges: The volatility of TNUoS and BSUoS charges results in higher risk for users, resulting in a risk premium which may ultimately be passed through to consumers.	Low

5.3.1 Deployment barriers

National Grid's connections data shows an average delay for demand of 30 months (skewed by some very long delays e.g. in South Wales) but does not indicate the capacity of demand in the queue. There is evidence from the Task Forces that connection of demand at distribution level may in some cases be limited by the availability of transmission exit capacity (see Section 5.5.1).

5.3.2 Efficiency of operations

Demand does not respond to signals of constrained capacity, since it is not typically participating in the BM (which is often attributed to the challenges of sourcing and aggregating DSR to sufficient scale to participate). The efficiency of the operation of the system could be improved if demand received short term signals of locational capacity constraints. This would be in cases where demand curtailment could provide a cheaper option for resolution of import constraints, which would otherwise be resolved by increasing output from a higher marginal cost generator.

5.3.3 Efficiency of investment

We have not identified any specific transmission exist related issues with respect to the efficiency of investment, although there is a general future potential issue that a reduction in peak (and total) transmission demand as a result of DG, or grid defection, could lead to partial stranding of elements of the transmission system. This could be offset by anticipated growth in LCTs, as National Grid's Consumer Power FES shows a pathway to a 15 GW increase in peak electricity demand by 2040 (although growth of the transmission system peak could be considerably slower as a result of distribution connected generation).

5.3.4 Allocation of risk

The same approach to estimate the impact of unpredictability of TNUoS and BSUoS charges has been used as for transmission entry. The cost of TNUoS risk is £12m/yr and the cost of BSUoS risk £3m/yr. The alternative CMP250 estimate of BSUoS risk assuming consistent over-recovery is £40mn to £100mn, but as set out in Section 5.2.4 we do not believe this is an appropriate measure in this instance.

5.3.5 Contributing issues

The distribution entry related issues which contribute to each wider system impact are set out in Table 17, including an assessment of the level of contribution (High/Medium/Low).

Table 17 - Transmission exit wider system impacts: contributing issues

Wider system impact	Linked issues	Contribution Level
Deployment barriers	No issues identified as relevant	
Efficiency of Operations	7. Constraint costs are socialised	Low
	8. Inefficient signals for capacity planning and network investment	Low
Efficiency of Investment	No issues identified as relevant	
Allocation of Risk	14. TNUoS charge predictability	Medium
	15. BSUoS charge predictability	Low

5.4 Distribution entry

The distribution entry wider system impacts are summarised in Table 18, with the most material impact being the deployment barriers for EG.

Table 18 - Distribution entry wider system impacts

	Impact description	Rating
Deployment barriers	The queue of generation waiting to connect to constrained parts of the distribution network is large, with around 20 GW of accepted connection offers waiting to connect as of May 2016 (see below for limitations on this metric).	High
Efficiency of operations	The current principles of access for flexible connections result in economically inefficient curtailment of distributed generation, relative to potential market- or price-based solutions for curtailment.	Medium
Efficiency of investment	The distribution network is currently managed with the expectation of the need to accommodate the firm entry capacity of generation and storage (with the exception of flexible connections[24]), with inefficient locational signals (including default DG generation credits[25] under CDCM) driving user investment. The utilisation of the network could be increased if signals and solutions for capacity release and more efficient curtailment mechanisms were used.	Medium
Allocation of risk	Curtailment risk: The allocation of curtailment risk on users under flexible connections may be inefficient, if these parties are not best placed to manage the risk. Charge predictability: Under the EHV Distribution Charging Methodology (EDCM), charges vary from year to year with little to no predictability, and hence allocating risks to users that cannot manage them.	Medium

5.4.1 Deployment barriers

Based on information from Ofgem's Unlocking Capacity Report[26], there was an estimated 20 GW of distribution entry projects with accepted connection offers waiting to connect as of May 2016, although there may be a material dropout rate of projects for reasons unconnected to network access and charging. Overall, the development of Embedded Generation is expected to continue to grow, with an increase of at least 10 GW of capacity expected by 2030[27]. The size of the queue may be an indicator of other issues such as the discrepancy between residual charging for EG and TG, which currently favours EG. However, the metric does indicate that requirements for capacity are not being met across the distribution network. In addition, this figure will not capture areas where users may be strongly discouraged from applying, by the size of the existing queue.

[24] Flexible connections allow for connectees' network access to be managed (generation curtailed or import adjusted) without direct payment in return for a cheaper connection.
[25] Embedded generation connected at LV or HV level to the distribution network are eligible to receive payment (credit)
[26] Unlocking the capacity of electricity networks (associated document), Ofgem, February 2017
[27] National Grid Future Energy Scenarios (FES) 2017, all scenarios project an increase in embedded generation capacity of at least 10 GW by 2030

The primary cause of the queue for areas of the network where DNOs are enabling connection offers through flexible solutions was identified to result from distribution network constraints in 75% of cases and transmission network constraints in 25% of cases. The latter is an Interface issue and covered in Section 5.6.1.

5.4.2 Efficiency of operations

Current principles of congestion management for flexible connections on the distribution system are rules based; either Last In First Off (LIFO) or Pro Rata. A market- or price-based approach, where users signal their willingness to be curtailed, and each user's sensitivity to the constraint could be factored in, would potentially be more economically efficient. Estimates of the potential increase in efficiency were developed by Baringa and Smarter Grid Solutions in their report for ELEXON on Active Managed Distributed Generation and the BSC[28], and ranged from a 5% to 45% increase in efficiency. Combined with assumptions on the total volume of flexible connections as of today, we estimate the annual impact to be in the range £0.6mn to £5.4mn per year (of a total £12mn of estimated lost revenue through curtailment under today's rules based approaches). This may increase in future years. For example, WPD intends to roll out flexible connections to all areas by 2021[29].

5.4.3 Efficiency of investment

The current approach of building the distribution network mainly to firm capacity requirements may lead to over-investment in the network and lower overall utilisation of assets since these have been sized to maximum requirements.

The deployment of flexible connection schemes can greatly reduce the requirement for network reinforcement. Estimates for the avoided network reinforcement cost through flexible connections by 2040 range up to £1,200mn, based on the NG FES projections of embedded generation (EG) capacity. This saving can only be achieved if the demand for flexible connections exist, and a flexible connection offer is a sufficiently attractive option. The range in the estimate reflects the variation between capacity projections, from a very modest increase in EG, resulting in minimal reinforcement costs, to a 54 GW increase in EG capacity, resulting in significant network reinforcement. These estimates assume that similar increases in network utilisation as seen in the UKPN Flexible Plug and Play project[30] can be achieved in network wide roll outs of flexible connections.

There is a high level of uncertainty around these figures as they are based on assumptions about the volume of spare capacity available, the voltage level of connections, and the cost of reinforcement.

Whilst flexible connections can unlock capacity, the choice of principles of access for flexible connections is important. For example, under LIFO specifically, the targeting of curtailment at the last user to connect is likely to lead to a lower total volume of connections, and creates no collective incentive for reinforcement, since earlier connectees, who experience lower curtailment, would be less willing to fund a reinforcement which primarily benefits later connectees.

[28] Active Managed Distributed Generation and the BSC, ELEXON, June 2014
[29] https://www.westernpower.co.uk/Connections/Generation/Alternative-Connections/ANM-Further-Info.aspx
[30] Flexible Plug and Play: Close Down Report, UKPN, 2015

For smaller EG, DUoS charges are not cost reflective as location is not accounted for within a DNO area and hence users who may impose higher costs on the network are charged the same as those in areas with lower costs. These costs may be incurred via future reinforcement to the network. Generators receive DUoS generation credits even in generation dominated areas.

5.4.4 Allocation of risk

With respect to allocation of risk there are three impacts to consider: stranding risk, allocation of curtailment risk, and the unpredictability in EDCM charges for generation users.

Stranding risk – connection charging

Connections at distribution follow the one voltage rule whereby the generator carries liability for these assets if reinforcement is required (see Section 3.2, Issue 20) and hence bears most stranding risk. The proportion of connectees paying for wider reinforcement are low: 95% of all distribution connections over the period 2010 to 2013 have not triggered any wider network reinforcement at all[31], often because these costs make the project uneconomical and hence it does not proceed.

Wider users bear some stranding risk. In the 5% of cases where reinforcement was triggered other network users pay, on average, around 41% of these reinforcement costs via DUoS[32]. Evidence from a review of WPD RIIO-ED1 expenditure suggests that deeper reinforcement paid for by the connecting user is small in comparison to shallow connection costs (£37.5m vs. £542.1m, noting that these figures cover both generation and demand).

Curtailment risk

Traditional connections at distribution receive very low compensation for curtailment (around £2.50/MWh). However, the risk of curtailment is very low and hence they are often considered 'firm' for practical purposes. Flexible connections allow distribution connected generation under these arrangements to be curtailed to manage congestion, in return for cheaper (and faster) connections. The level of curtailment may be significant, and is uncapped, although the DNO will provide the generator an expectation (but not a guarantee) of likely curtailment levels. This may amount to significant proportion of user revenue (5% curtailment might be considered typical, which translates into lost revenue). Users connecting under flexible connection agreements hold the risk of curtailment, with an estimated annual value currently of £12m as set out in Section 5.4.2.

The allocation of curtailment risk to users may have a subsequent impact on the efficiency of investment. If the future value of curtailed energy for a group of users exceeds the cost of the relevant network reinforcement, then there is a case for the investment to be made. However, the DNO currently has no exposure to curtailment costs, and users may not be aware of the potential value. Without clear mechanisms to signal or trigger network reinforcement and thus alleviate constraints, when economically efficient to do so, there will be an underinvestment in the network. This is in contrast to transmission, where the SO has a direct responsibility for assessing the trade-off between constraint and reinforcement costs, under the NOA process.

[31] Ofgem Guide to Electricity Distribution Policy, 2014

[32] Ofgem Guide to Electricity Distribution Policy, 2014

The situation described above is most likely to occur in situations where curtailment has turned out to be higher than estimated, perhaps due to reductions in demand or the growth of microgeneration in the area.

Charge predictability

EDCM charges vary from year to year, with little to no predictability of the variation. Since EDCM users are not in a position to forecast and therefore respond to these changes in charges, there is a case to say that allocating this risk to users is not driving efficiency.

The variability was assessed in Annex F of the EDCM Review[33], which found an average of 5% annual variability in export tariffs. The total EDCM annual charges of £150m and the assumed proportion paid by exporting users (25%) leads to a value at risk of £2m, and applying our 8% cost of capital assumption (as used in other charge predictability calculations) the risk capital required on an annual basis is significantly less than £1m. The variability in CDCM charges is much lower than for EDCM, and hence we have not quantified this impact.

5.4.5 Contributing issues

The distribution entry related issues which contribute to each wider system impact are set out in Table 19, including an assessment of the level of contribution (High/Medium/Low).

Table 19 – Distribution entry wider system impacts: contributing issues

Wider Impact	Linked issues	Contribution Level
Deployment Barriers	1. Lack of capacity options	Medium
	2. No measure of value to user of connection	High
	4. Lack of defined access rights and barriers to access right trading	Medium
	8. Inefficient signals for capacity planning and network investment	Medium
	13. Lack of efficient principles of congestion management at distribution	Low
Efficiency of Operation	13. Lack of efficient principles of congestion management at distribution	High
Efficiency of Investment	1. Lack of capacity options	Medium
	4. Lack of defined access rights and barriers to access right trading	Medium
	8. Inefficient signals for capacity planning and network investment	Medium
	9. Lack of LV/HV locational signals	Medium
	13. Lack of efficient principles of congestion management at distribution	Low

33 EDCM Review Group Report for the Methodologies Issues Group (MIG) of the Distribution Charging Methodologies Forum (DCMF), December 2015

Allocation of Risk	13. Lack of efficient principles of congestion management at distribution	Medium
	16. EDCM charge predictability	Low

5.5 Distribution exit

The distribution exit wider system impacts are summarised in Table 20. There are two High materiality impacts, deployment barriers and efficiency of investment, mainly linked to potential large scale future uptake of LCTs such as EVs and Heat Pumps (HPs) by small users. In comparison to other impact areas where the issue is current, this issue is highly uncertain based on future assumptions of deployment rates. The 2017 FES set out a range of between 2 to 9 million EVs by 2030, and 1 to 4 million HPs.

Table 20 - Distribution exit wider system impacts

	Impact description	Rating
Deployment barriers	There is the potential for constraints on EV or HP deployment in future due to delays to LV network upgrades (given the potential high volume of reinforcement required). This is not a current issue, but it has the potential to be highly significant by 2025-2030. For larger users, deployment barriers exist in some locations, in part due to issues on the transmission system.	**High**
Efficiency of operations	Inefficient user behaviour (through lack of signals) increases peak demand on LV/HV network and hence increases losses, though reduction in losses achievable is likely to be small. There is a lack of incentives for demand to participate in network constraint management. Time of use signals via Red/Amber/Green in DUoS may insufficient to incentivise efficient behaviour.	**Low**
Efficiency of investment	Possible clustering of LCTs may increase the peak load on LV feeders. LV feeder reinforcement will be required to accommodate projected capacities. Part of this reinforcement cost could be avoided through peak shifting of LCT loads.	**High**
Allocation of risk	There is a risk of stranding of investment due to broader policy environment surrounding LCTs, and the risk currently sits with DUoS paying customers. Under the EHV Distribution Charging Methodology (EDCM), charges vary from year to year with little to no predictability, and hence allocating risks to users that cannot manage them.	**Medium**

5.5.1 Deployment barriers

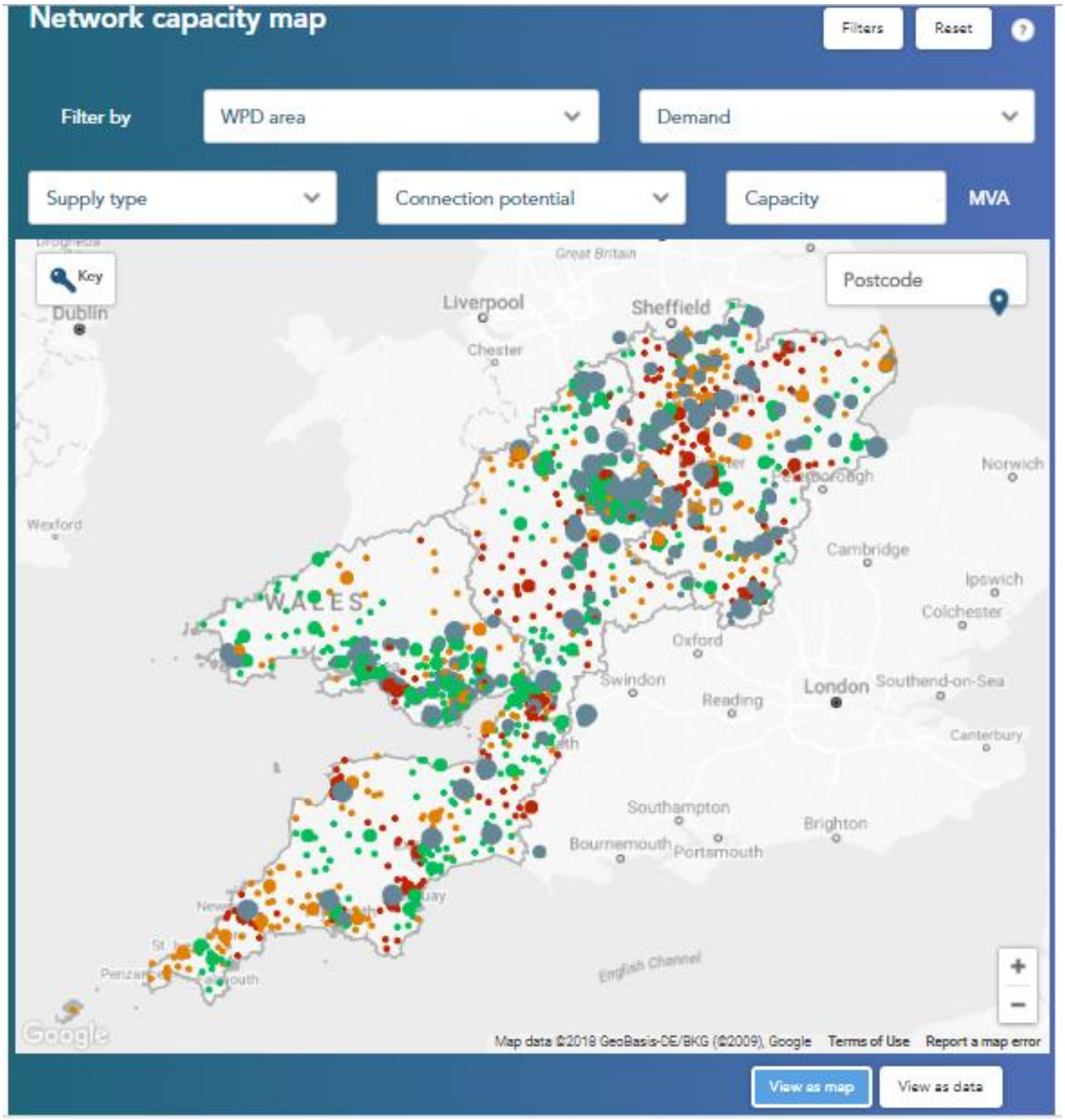
Deployment barriers are potentially highly significant, since clustering on LV feeders could create the need for a large number of reinforcements creating connection delays.

There is no current queue at LV, but we have considered the potential for constraints to occur in the future. This view is based on conclusions from My Electric Avenue[34], combined with EV and HP uptake forecasts from FES 2017. Clustering of EVs is expected, but there is little historic evidence to base assumptions on. On the simple assumption of concentration of EVs on 50%[35] of feeders, spare capacity could be used up on average as early as 2025 under National Grid's Two Degrees scenario (the scenario with highest EV deployment). If reinforcement did not occur in a timely fashion, this could lead to queues equivalent to several GWs. Clearly constraints could occur a lot earlier in certain locations.

[34] My Electric Avenue project, http://myelectricavenue.info/, EA Technology on behalf of Scottish and Southern Energy Networks (SSEN)
[35] Baringa assumption

Separately, large demand connections are facing delays and queues in some regions such as the East Midlands, in some cases as a result of a need for reinforcement to the transmission system. See for example WPD's demand heat maps shown in Figure 3, which illustrate the issues in many areas[36]. The total size of the demand queue is not readily available.

Figure 3 - WPD network capacity map (April 2018)



[36] http://www.westernpower.co.uk/connections/generation/network-capacity-map.aspx

5.5.2 Efficiency of operations

With regards to losses, inefficient user behaviour (through lack of accurate signals of the impact of users on losses) increases peak demand on LV/HV network, and consequently losses. The reduction in losses achievable is likely to be small, estimated to be around £7mn per annum based on 2017 wholesale prices. This estimate covers the proportion of losses due to variable losses on LV, and the potential for improvement (~4%, estimated from a study by WPD[37]).

A lack of incentives and dispatch signals for demand to participate in network constraint management at the distribution level is another source of inefficient operation. For example, under current flexible connection schemes for EG, no signal is provided to demand users (or storage) to incentivise changes in their demand profiles to reduce curtailment of generation. The correct signals could have the potential to reduce the overall curtailment of generation and therefore increase the utilisation of the network. Due to the relatively small capacity of EG connected under flexible connections this is currently a low materiality issue, although future increases in flexible connections would increase the importance of this issue.

Time of use signals via Red/Amber/Green in DUoS may be insufficient to incentivise efficient behaviour. Due to the inflexible structure of the charge, the time periods where network congestion is most prevalent may not necessarily align with red bands and are unlikely to occur during all red bands. Quantification of this issue would require a study of how DUoS customers currently respond to Red/Amber/Green price signals, and how this affects the wider system. Domestic customers are generally not currently on Red/Amber/Green DUoS tariffs, though this will change as customers move to HHS and face banded ToU DUoS tariffs.

5.5.3 Efficiency of investment

There is the potential for significant reinforcement to be needed to accommodate the uptake of LCTs by small users, the cost of which would be socialised rather than signalled to users under the current arrangements. Currently, uptake of LCTs by existing domestic users would not be subject to a connection charge[38], and smaller user network usage may exceed capacity of distribution network, as set out in Section 3.2, Issue 5. In addition, the lack of locational signals at HV and LV levels under the current CDCM model means that DUoS does not provide a clear signal of the impact of LCT uptake by small users. A related but separate issue is the potential need to accommodate larger EV charging installations, such as consumer fast charging points or commercial fleet charging. The issues are potentially more limited since these installations would these would trigger a connection application/charge as per any other larger demand user.

Estimates of the potential reinforcement required (for households) have been based on the reinforcement cost for LV and the potential increase in load due to EVs and HPs. Part of this reinforcement cost could be avoided through peak shifting of LCT loads. Using assumptions from My Electric Avenue on the potential reduction in After Diversity Maximum Demand (ADMD) from managed charging of EVs, we have estimated the potential savings in reinforcement cost if users are exposed to the costs of their impacts on the system, and adjust behaviours accordingly. This is of the

[37] Comparison of price incentive models for locally matched electricity networks, WPD, 2017

[38] With the exception of new build connections which would be liable for reinforcement costs

order of up to £430mn (NPV to 2040), with the large range as a result of the highly varying levels of deployment in EVs across the FES.

5.5.4 Allocation of risk

There are two effects under allocation of risk: the risk of stranding of reinforcement to accommodate LCTs as a result of a change in the broader policy environment, and the specific risk in EDCM tariffs for importing users.

Stranding risk

The uptake profile and the usage profile of LCTs are likely to be heavily influenced by technology developments and broader policies. For example, an uptake in domestic EV charging points may trigger reinforcement of the LV network but if EV users were subsequently to shift to fast charging points outside of the home then this could lead to the LV network investments being stranded. Currently, this risk of stranding of investment would sit with DUoS customers as a whole as the network reinforcement costs would be socialised via DUoS charges. This is currently a low materiality issue due to the relatively low uptake of EVs, although in future this could become a more material issue with greater EV deployment. The risk would be decreased by the success of measures to manage demand to avoid the need for reinforcement in the first place (in other words, this is a lower impact if Efficiency of Investment is improved).

Charge predictability

Under the EDCM, charges vary from year to year with little to no predictability, and hence allocating risks to users that cannot manage them. The estimated cost of unpredictability in EDCM for demand users is calculated in the same way as for generation users but is higher due to a higher annual variability (20%) and a greater proportion of costs recovered from demand.

Given the total EDCM annual charges of £150m and the assumed proportion paid by importing users (75%) leads to a value at risk of £23m, and applying our 8% cost of capital assumption (as used in other charge predictability calculations) the total risk capital required on an annual basis is £2m.

5.5.5 Contributing issues

The demand exit related issues which contribute to each wider system impact are set out in Table 21, including an assessment of the level of contribution (High/Medium/Low).

Table 21 – Distribution exit wider system impacts: contributing issues

Qualitative assessment	Linked issues	Contribution Level
Deployment Barriers	5. Smaller user network usage may exceed capacity of distribution network	High
	9. Lack of LV/HV locational signals	Medium
	10. Lack of locational line loss signals	Low
	12. Inefficient volumetric based network charges	Medium
	16. EDCM charge predictability	Low
Efficiency of Operation	9. Lack of LV/HV locational signals	Medium
	10. Lack of locational line loss signals	Low
	12. Inefficient volumetric based network charges	Medium
Efficiency of Investment	5. Smaller user network usage may exceed capacity of distribution network	High
	9. Lack of LV/HV locational signals	Medium
	10. Lack of locational line loss signals	Low
	12. Inefficient volumetric based network charges	Medium
	16. EDCM charge predictability	Low
Allocation of Risk	5. Smaller user network usage may exceed capacity of distribution network	High
	16. EDCM charge predictability	Low

5.6 Interface

Users seeking a connection to the transmission and distribution networks can expect to face a significant variation in connection costs and on-going network charges. These variations in costs are driven by differences in policy and charging methodology between voltage levels. These differences define the 'Interface' category as they can distort the investment decisions made between the transmission and distribution networks.

Table 22 provides an illustrative example of the differences in connection costs and on-going network charges between an intermittent generator connecting to the transmission network in Scotland and an intermittent generator connecting to the distribution network in Southern England. These charges will vary significantly with location.

Table 22 - A comparison in costs faced by intermittent generation connecting at transmission level in Scotland and distribution level in Southern England

	Connecting to the transmission network	Connecting to the distribution network
What you buy:	• Transmission Entry Capacity (TEC) • Access is 'financially firm'. If your output is curtailed (or increased) the SO must make you financially whole. • The concept of a non-firm/flexible connection at transmission does not currently exist[39].	• No clear access product comparable to TEC at transmission • Access not 'financially firm'. Connection can be interrupted with little compensation, though in practice the risk of interruption under a standard connection agreement is minimal and is therefore considered 'firm'. • Generation can be offered 'flexible' connections, accepting curtailment of generation when the network is constrained in return for a reduced connection cost.
Costs for sole use assets:	• User liable for costs relating to sole use assets, through two charges. – Connection charge: **~£20/kW** – Local circuit and local substation charge s are recovered through local TNUoS **: £0-4/kW/yr**, not all generators face a local charge	• User liable for costs relating to sole use assets. • Charge: **~£20/kW** • Recovered through connection charge
Costs reflecting wider reinforcement needs:	• Connection charges are 'shallow': no user liability for wider reinforcement needs • Costs of wider reinforcement are recovered through wider TNUoS charges (see below)	• Connection charges are 'Shallow-ish': liable for reinforcement costs up to one voltage level above that are required to accommodate the connection. "Second comer" rules mean that if further connection occurs and makes use of these assets, original party receives some value back • Reinforcement above one voltage level recovered from wider DUoS customers (see below). • If GSP reinforcement is required, this is treated as a connection asset and user would pay for this

[39] Some users have local assets with no redundancy, and hence pay lower charges but are not compensated if the specific asset is unavailable. This is the case for offshore generators with single circuit radial connections

	Connecting to the transmission network	Connecting to the distribution network
What happens when the network is congested where you want to connect:	• Following Connect & Manage, essentially users are able to access the network before SQSS network standard met. • The impact of connections must therefore be managed by the SO in order to maintain network security standards. The costs of doing so are socialised amongst wider users. The annual constraint management costs attributable to C&M capacity as of September 2015 equated to an average cost of **~£64/kW of C&M capacity**.	• If reinforcement within one voltage level is required to accommodate the connection these costs will be reflected in the connection charge: **>£100/kW** • In certain circumstances, flexible connections can be offered whereby reinforcement is avoided but subsequent curtailment results in lost revenues: **~£25/kW/yr** • Reinforcement requirements above one voltage level or at transmission level can prevent or delay connection.
What annual network charges you face:	• Network charges (TNUoS) on each MW of TEC. – The forward looking part of TNUoS charges sends a broadly cost reflective signal so that it is more expensive to connect in some TNUoS zones than others. – Average Intermittent Generator locational charge in Scotland: **~£20/kW/yr** • BSUoS charge: **~£6.50/kW/yr**	• Distribution UoS Export charges: – Non-intermittent generation receives locational credits at all distribution voltage levels – Intermittent generation receives locational credits when connected at the HV distribution level. Resulting in total export charge of – **~£-20/kW/yr at HV,** – At EHV level, charges are determined for each connection: **~£1/kW/yr** • Avoided Supplier BSUoS charge benefit: **~£6.50/kW/yr** • EG reduces GSP demand and thus benefits through the Embedded Export Tariff: **~£1/kW/yr**
What happens if you no longer use your connection:	• The generator has a liability for two years' worth of TNUoS charges if they disconnect without providing notice.	• No commitment to DUoS charges • User has paid upfront for connection assets

The differences in these charges are the basis for the majority of the Interface wider system impacts summarised in Table 23.

Table 23 - Interface wider system impacts

	Impact description	Rating
Deployment barriers	The significant potential difference between avoided BSUoS cost and DUoS benefit received by small distribution connected Generation (DG) and the locational TNUoS tariff paid by transmission connected Generation (TG), along with assumed transmission rights for DG, can make the financial case for a new DG development more attractive over a large EG or TG. This results in a greater deployment of EG which may contribute to the distribution connection queue. Transmission entry issues are a contributing factor to the distribution entry queue in some locations.	Medium
Efficiency of operations	Locational signals in Triad may lead to inefficient dispatch for demand users (including demand with onsite generation) and users in receipt of the Embedded Export Tariff, leading to displacement of more efficient transmission connected generation. The relative size of locational Embedded Export Tariffs limits the materiality of this impact.	Low
Efficiency of investment	There may be distortions in the deployment of EG and TG due to discrepancy in voltage level access and charging. This could result in excessive system costs. Additionally gaps in charging signals for DG in areas of exporting GSPs could drive higher transmission network costs.	Medium
Allocation of risk	Stranding risk: There is a potential asset stranding risk for customers as a result of shallow connection charges at transmission, compared to deeper charges for distribution users. Curtailment risk: Distribution connected generation on flexible connections has different curtailment risk to transmission connected generation, which is financially firm under Connect & Manage.	Low

5.6.1 Deployment barriers

There are significant differences between avoided BSUoS cost and DUoS benefit received by small distribution connected Generation (DG) compared to the locational TNUoS tariff paid by transmission connected Generation (TG). Along with assumed transmission rights for DG, this can make the financial case for a new DG development more attractive over Large EG or TG. Residual charges have historically been the main contribution to this discrepancy, but within locational charges a discrepancy exists and typically favours EG. This will be a contributing factor to the size of the distribution queue (section 5.4.1).

Further related issues are:

- Different depths in connection charging across transmission and distribution, with transmission connection being shallow and distribution somewhat deeper
- The C&M regime allows generators to connect ahead of wider transmission system reinforcements (a factor in the smaller queue at transmission). The applicability of C&M to distribution connections has not been clearly defined or applied. Where a distribution

connection would create a need for wider works at transmission level, C&M arrangements could allow the connection to proceed without waiting for these works to be complete and could allow the EG to receive compensation for any relevant curtailment.

- Lack of explicit transmission entry capacity rights for smaller EG, which essentially get assumed rights to transmission entry (to sell wholesale power or provide ancillary services to the SO, for example) without any specific charge since the EET cannot fall below zero. If reinforcement of the GSP is required, smaller EG will pay for this since GSP reinforcement is treated as a connection charge.

The distribution generation connection queue is in part due to transmission network constraints in some regions. One example is in South Wales, where National Grid has published a letter[40] under the Statement of Works process indicating that the transmission system in the region is unable to accommodate additional distribution generation capacity. In addition, users may be strongly discouraged from applying to join the queue. On the other hand, not all projects in the queue would necessarily proceed if connection capacity were available.

5.6.2 Efficiency of operations

The impact on efficiency of operations is related to the inefficient time of use signal from demand TNUoS charging. Under the Triad methodology, demand users (including those with onsite generation) and those receiving the EET have charges calculated based on consumption in three Triad periods. These periods are not known ex-ante and therefore users are incentivised to engage in "Triad chasing" to reduce consumption/increase generation in periods which are likely to be defined as a Triad. Due to the increasing volume of capacity engaged in this behaviour, forecasting Triad periods is becoming more difficult.

We have estimated the impact of this issue on market dispatch efficiency. The analysis performed for the CMP 264 / CMP 265 impact assessment[41], suggests that in 2022 users would need to operate for 78 hours in order to ensure operation over the Triad period, and assumes 2 GW of gas engine capacity would engage in this activity. Combined with our own estimates of the Short Run Marginal Cost (SRMC) difference between a 40% efficient gas engine and a 50% efficient transmission connected CCGT (around £20/MWh), we estimate an impact in the order of £3m per annum (based on locational TNUoS only, i.e. excluding the effect of the residual). There is significant uncertainty on this estimate but this is sufficient to qualify this as a low materiality issue.

5.6.3 Efficiency of investment

As with deployment barriers (5.6.1), the differences between the access and charging regimes across transmission and distribution are likely to lead to inefficient investment at both transmission and distribution to accommodate more EG. The lack of defined transmission entry rights and

[40] https://www.westernpower.co.uk/docs/connections/Generation/Statement-of-Works/WPD-South-Wales-Letter-19-May.aspx
[41] Embedded Benefits: Consultation on CMP264 and CMP265 minded to decision and draft Impact Assessment, Ofgem, March 2017

transmission charges for EG that increase constraints contributes to inefficient investment in the transmission network.

The barriers to deployment at distribution entry limit the deployment of EG and therefore the potential impact on efficiency of investment (i.e. high distribution reinforcement costs that limit deployment may be limiting the increase in transmission reinforcement)

In addition, the use (and cost) of distribution level curtailment is unlikely to be taken into account in transmission investment decisions.

5.6.4 Allocation of risk

Two areas in which risk allocation is significantly different between transmission and distribution are stranding risk and curtailment risk. We have assessed the materiality of these issues separately in the relevant sections.

Stranding risk

Given the structure of transmission access and charges, with shallow connections and limited post-commissioning user commitment, there is a potential asset stranding risk for wider customers (Section 5.2.4). In particular, TG carries no liability for attributable assets once commissioned, but does face user commitment of two years for wider assets (via TNUoS charges).

This is in contrast to connections at distribution which are deeper (shallow-ish) and hence the generator carries liability for these assets if reinforcement is required (as set out in Section 5.4.4). However, for EG that triggers transmission reinforcement, there is no user commitment to the transmission assets that are built.

Curtailment risk

Curtailment risk differs between voltage levels, with TG being financially firm (compensated for curtailment) under Connect & Manage, whereas on distribution there is no compensation, as set out in Section 5.4.4.

Flexible connections allow distribution connected generation under these arrangements to be curtailed to manage congestion, in return for cheaper (and faster) connections.

5.6.5 Contributing issues

The interface related issues which contribute to each wider system impact are set out in Table 24, including an assessment of the level of contribution (High/Medium/Low).

Table 24 – Interface wider system impacts: contributing issues

Qualitative assessment	Contributing issues	Contribution Level
Deployment Barriers	3. Lack of transmission import capacity rights for distribution network	Medium
	11. Inefficient time of use signal from Triad methodology	Low
	20. Different depths in connection charging across T and D	Medium
	21. Voltage level differences in operating cost charging methodologies	Medium
	22. Voltage level differences in network cost charging methodologies	Low
Efficiency of Operation	11. Inefficient time of use signal from Triad methodology	11. Low
Efficiency of Investment	3. Lack of transmission import capacity rights for distribution network	Medium
	20. Different depths in connection charging across T and D	Low
	21. Voltage level differences in operating cost charging methodologies	Low
	22. Voltage level differences in network cost charging methodologies	Medium
Allocation of Risk	7. Constraint costs are socialised	High
	19. Different risk allocation across transmission and distribution	Medium
	21. Voltage level differences in operating cost charging methodologies	Low

5.7 Summary of impacts

The wider system impacts are summarised in Table 25. The most material impacts are in the areas of distribution entry and exit. Our assessment of priority areas below considers these areas as well as the contributing Interface issues.

Table 25 - Summary of impacts

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

6 Conclusions

Based on our assessment of the issues and wider system impacts related to network access and forward looking charges, we conclude that there are three priority areas for further consideration. These are set out below.

Ensuring that access and charging arrangements for small users are ready for the uptake of LCTs

Under current arrangements for small users, there is a risk that new loads like EVs create significant pressures on networks at peak times. This could result in deployment barriers or expensive reinforcement that could be avoided with more flexible usage.

Whilst deployment rates are uncertain, there is the potential for spare capacity to be used up by 2025, and where clustering occurs, earlier in certain locations.

The current charging arrangements would mean that the costs of required reinforcement would not necessarily be charged to those users who are creating the requirement. For example, we estimate that a customer with a standard domestic 3.5kW EV charging point will double its contribution to peak demand, and yet its DUoS charge would increase by only around 50% under current arrangements.

There may also be inefficient investment in new LV distribution network infrastructure to accommodate these technologies. Whilst this is not an immediate issue, deployment profiles from FES suggest that uptake could rapidly increase. We have estimated the potential saving in reinforcement cost if users are exposed to the costs of their impacts on the system and adjust their behaviours accordingly to be of the order of up to £430mn (NPV to 2040).

Progress in this area would require addressing Issue 5 - Smaller user network usage may exceed capacity of distribution network. Other contributing issues include:

- 9. Lack of LV/HV locational signals
- 10. Lack of locational line loss signals
- 12. Inefficient volumetric based network charges

Ensuring that access for distribution entry is properly valued and signalled to users

There was an estimated 20 GW of distribution entry projects with accepted connection offers waiting to connect as of May 2016. Whilst we have highlighted the limitations of this metric, overall the development of Embedded Generation is expected to continue to grow, with an increase of at least 10 GW of capacity expected by 2030[42]. There are a range of factors that may impact queue length beside connection delays (including existing discrepancies in residual charging which favour EG over TG), but this figure provides some indication of the extent to which requirements for capacity are being met across the distribution network, and potentially means that investment in new

[42] National Grid Future Energy Scenarios (FES) 2017, all scenarios project an increase in embedded generation capacity of at least 10 GW by 2030

technologies is being held back. This outcome is the result of a series of interrelated issues, including the lack of locational and temporal signals for the value of capacity to existing and new users, which means that capacity is not allocated on either a short or long term basis to those who value it most.

A significant portion of the queue is a result of the lack in available capacity at transmission to accommodate the EG. The treatment of the costs of reinforcement is a further barrier (e.g. GSPs are treated as connection assets).

DNOs do not receive clear signals for investment, particularly where this would currently require coordination between a number of separate applicants.

The current approach of building the distribution network mainly to firm capacity requirements may lead to over-investment and lower utilisation of assets.

The lack of efficient principles of congestion management at distribution will also be a contributing factor in the future as the number and volume of flexible connections increase, with inefficient curtailment increasing overall curtailment volumes and reducing network utilisation.

Whilst issues related to signalling of value also exist at transmission, these are less material (as evidenced by the smaller connection queue of 1.6 GW) due to the Connect & Manage arrangements and the greater implicit sharing of capacity as enabled by active constraint management by the SO.

Progress in this area would require addressing some or all of the following issues in the area of distribution entry:

- 1. Lack of capacity options
- 2. No measure of value to user of connection
- 4. Lack of defined access rights and barriers to access right trading
- 8. Inefficient signals for capacity planning and network investment
- 9. Lack of LV/HV locational signals
- 13. Lack of efficient principles of congestion management at distribution

Of these issues, addressing the lack of signals for the value of connections (Issue 2) is the highest priority, since this, in combination with Issue 4, is the underlying driver of capacity not being allocated efficiently. Interface issues related to discrepancies in charging also contribute to the size of the distribution entry queue and addressing these as set out below should complement changes to distribution access.

Resolving interface issues between transmission and distribution

Whilst the TCR aims to remove some of the most significant distortions between TG and EG (related to the charging of residuals), differences in access and forward looking charges remain significant, and the potential for distorting investment decisions remains.

Generation connected in a generation dominated network area can face very different network charges, depending on the voltage level it is connected to, with small EG receiving a net benefit and large EG and transmission generation facing a cost.

This is estimated to be an average cost through TNUoS charges to large EG and transmission generation of around £20/kW/yr in generation dominated areas. At HV level on the distribution network a small EG can expect to receive generation credits worth around £20/kW/yr, with indicative DUoS charges at EHV around £1/kW/yr. Smaller EG may also receive a locational TNUoS benefit via the EET which ranges from zero in generation dominated areas to up to £12/kW/yr in demand dominated areas. With regards to connection charging and assumed access rights, distribution connections are deeper but also come with assumed access to transmission (to sell wholesale energy or ancillary services), without facing a corresponding charge (i.e. EG do not face TNUoS charges behind exporting GSPs, as a result of the charging methodology that does not allow the EET to become negative).

Progress in this area would require addressing some or all of the following issues on the Interface between transmission and distribution:

- 3. Lack of transmission import capacity rights for distribution network
- 11. Inefficient time of use signal from Triad methodology
- 20. Different depths in connection charging across T and D
- 21. Voltage level differences in operating cost charging methodologies
- 22. Voltage level differences in network cost charging methodologies

Of these issues, addressing differences in network charging and connection charging should be highest priority.

Other issues

Transmission constraint management costs are socialised through BSUoS charges and therefore the charge is not reflective of the cost a user imposes on the network. Wider customers therefore face a higher charge when generation chooses to locate in a constrained area. This is particularly the case for users that have connected under Connect & Manage arrangements, where the annual constraint costs attributable to capacity connected under C&M as of September 2015 equated to around £64 per kW, which is significantly higher than the BSUoS charges these parties face. This is likely to decrease owing to the large network reinforcements that are due to be commissioned in 2018 (Western HVDC Link, Caithness-Moray cable).

This may also be leading to higher overall costs since these constraint costs must be managed in the interim period before wider reinforcement is completed. Since these costs are not signalled to users, it is not possible to say that these parties are connecting in efficient locations.

Wider issues with transmission access are related to a lack of capacity options and signals which could be addressed alongside the socialisation of constraints to better value access to transmission:

- 1. Lack of capacity options
- 2. No measure of value to user of connection
- 4. Lack of defined access rights and barriers to access right trading

The issues of charge predictability in TNUoS, BSUoS and EDCM (Issues 14, 15 and 16) are also significant. Use of system charges can be volatile and difficult for users to predict and manage, especially in the case of BSUoS and EDCM. The impact across generation and demand has been estimated as £24m/yr for TNUoS, £6/yr for BSUoS, and £2m/yr for EDCM.

Where issues or wider system impacts are rated as low materiality this should not be taken to imply that there is no issue, and if these are not taken forward under the current review then other methods for addressing these (e.g. through standard code governance) should be considered.

Input to Ofgem's assessment of impacts

Our analysis is explicitly concerned with the materiality of issues with current arrangements, and does not comment on the addressability of each area or issue, nor which policy options would be most suitable to address these impacts, both of which will be considered separately by Ofgem.

Appendix A Distributional assessments

In this section we describe the distributional impacts of the identified issues, the quantitative metrics developed to evaluate the impacts, and the overall assessment of each issue.

Capacity allocation

Table 26 - Capacity allocation issue distributional impacts

Issue	Assessment
1. Lack of capacity options	On the transmission network the capacity entitlement (TEC) allocated to users does not necessarily reflect the users' overall capacity requirement through the year. Generators with an underutilised TEC are effectively overpaying through TNUoS locational charges (although this is offset to some extent through the sharing factors introduced under CMP213[43], which reduces charges for lower load factor generators). Short-term TEC is only made available where there is spare capacity but TNUoS payment does not reflect this, as it is pro-rated to annual TNUoS payment, so there is a distributional effect between short-term TEC holders and other users. This issue is not limited to transmission. Distribution connected generation or demand which may have a complimentary generation/load profile to existing connections in a constrained area may be prevented from connecting due to the lack of profiled capacity options, though flexible connections could provide access for generation in some circumstances.
2. No measure of value to user of connection	On the distribution network a significant volume of existing capacity could be released to the current queue. A UKPN study[44] showed that only 45% of EG fully utilise their connection capacity in a given year, where full utilisation is defined as annual peak generation greater than 75% of the rated connection capacity (as per 12.11C National terms of Connection). This implies that there exists a large volume of unutilised existing capacity which could be allocated to new connections, estimated as over 1 GW on UKPN's networks alone. The issue is likely to be less material on the transmission network due to generation capacity being able to connect before wider network reinforcement occurs under Connect & Manage (C&M) and TNUoS charges being capacity based, thereby providing some incentive to release unused TEC. Connection queues are further exacerbated as existing 'capacity holders' may have a price at which they would release capacity back to the connections queue but there is no current mechanism to allow for this.
3. Lack of transmission import capacity rights for	As the lack of a formal definition of transmission access rights for EG may result in inefficient network reinforcement at transmission as reinforcement decisions do not fully reflect EG transmission access requirements, there may be a lack of transmission

[43] CMP213: Project TransmiT TNUoS Developments modified the CUSC so that the TNUoS charging methodology recognises that the impact on incremental transmission network cost varies for generators with different characteristics as well as location

[44] Distributed Generation Customer Forum, UKPN, 25th February 2016

distribution network users	access capacity available to EG when desired. The issue therefore manifests in the wider system impacts of deployment barriers and efficiency of investment (Section 5).
4. Lack of defined access rights and barriers to access right trading	The inability, or difficulty, of current network users to trade network access rights reduces the ability or likelihood of excess network access rights being released to other users, or those that value access more. The issue therefore manifests in the wider system impacts of deployment barriers and efficiency of investment (Section 5).
5. Smaller user network usage may exceed capacity of distribution network	Smaller users do not face a capacity charge linked to their peak demand. Under HHS tariffs, customers may face a time-of-use (ToU) charge but with a wide red band and no locational element (other than variation between DNO regions). A domestic customer with a high peak demand due to LCT (EV or heat pump) uptake therefore does not face a cost reflective charge. The reinforcement costs triggered by high LCT penetration will then be socialised to wider customers. Under the current domestic unrestricted tariff rate, we estimate that the average annual DUoS charge for a customer with a standard domestic 3.5kW EV charging point will increase by around 50%, although their contribution to peak demand (after diversity) will double. This assumes an increase in after diversity maximum demand (ADMD) for EV users of around 1kW as found in the My Electric Avenue project, the charging profile and technical specifications of a standard EV, and the average daily vehicle distance travelled in GB.
6. Access and charging arrangements for IDNOs may not be cost reflective	There is currently a lack of data to evaluate the distributional impact of this issue as the relevant information is not collated by Ofgem. However, it is likely that the distributional impact of this issue is not significant relative to other identified issues, given the relatively low proportion of users served by an IDNO network.

Locational signals

Table 27 - Distributional impacts of locational signal issues

Issue	Assessment
7. Constraint costs are socialised	Some transmission-connected generators cause high constraint costs but pay roughly the same BSUoS charges as other network customers who cause no constraint costs or alleviate constraints. Locational TNUoS does not reflect constraint costs directly and a low generation TNUoS charge is possible in a constrained area with excess generation and vice versa. Constraint costs are most prevalent in areas where a high capacity of generation has connected under connect and manage (C&M). The annual constraint costs attributable to capacity connected under C&M as of September 2015 equated to around £64 per kW of C&M capacity, which far exceeds the BSUoS charges that those generators face. These constraint costs are socialised amongst, and result in higher costs for, wider customers.
8. Inefficient signals for capacity planning and network investment	The issue has a limited distributional impact since it does not have a direct impact on access or charges and hence manifests in the wider system impacts of deployment barriers and efficiency of investment (Section 5).

9. Lack of LV/HV locational signals	CDCM charges are not cost reflective as location is not accounted for within a DNO area. Customer charges in constrained areas are lower than their network impact would suggest, and customers in unconstrained areas are arguably overpaying. Generators are automatically credited even in generation dominated areas. These Generator credits can result in an annual net DUoS benefit of around £20/kW (locational and residual elements) and yet they could be adding to costs, leading to other users paying more.
10. Lack of locational line loss signals	The line loss charges made to HV and LV customers are not cost reflective. Line losses are currently socialised through DUoS amongst wider customers. In practice, line losses vary across the distribution network, dependant on network topology and asset utilisation. Therefore, users that contribute to greater line losses do not face the full associated costs. However, the distributional impact of variation in line losses is likely to be small relative to the impact of CDCM charges in Issue 9.

Inefficient dispatch

Table 28 - Distributional impacts of inefficient dispatch issues

Issue	Assessment
11. Inefficient time of use signal from Triad methodology	Through the incentive for Triad chasing by EG, TNUoS customers are in effect helping to fund savings in wholesale and Capacity Market costs by reducing system peak load. Although there is commonality in the user groups there will still be some distortive effects since the charge base differs for TNUoS, wholesale electricity and Capacity Market charges. In addition, transmission generators see a reduced level of demand due to Triad chasing of EG, resulting in potentially foregone revenues.
12. Inefficient volumetric based network charges	Volumetric charges do not reflect the network cost impact of most users on a temporal or locational basis, which largely depend on short term peak utilisation of assets. Small consumers with a high peak to average demand ratio do not currently fully face the costs of their impact on the system through DUoS charges under unrestricted tariffs. Banded volume based charges based on ex-ante peaks may or may not be cost reflective.
13. Lack of efficient principles of congestion management at distribution	Generators with flexible connections on the distribution network are not curtailed in a technical or economically efficient order. The current principles of access do not take a generator's value of network access or technical sensitivity to a constraint into consideration. Curtailment volumes and lost revenues of generators with flexible connections are therefore increased. It is estimated that economically inefficient curtailment results in up to £6/kW/year in excess lost revenues for EG with flexible connections, based on the figures from the ELEXON report on Actively Managed Distributed Generation and the BSC[45].

Signal predictability

Table 29 - Distributional impacts of signal predictability issues

Issue	Assessment
14. TNUoS charge predictability	The distributional impact of this issue is between parties who pay TNUoS (TG and demand), and those who receive the Embedded Export Tariff (EG). This is captured

[45] Actively Managed Distributed Generation and the BSC, ELEXON, June 2014

	under the voltage level differences in network cost charging (issue 21). The main impact of this specific issue is on the wider system.
15. BSUoS charge predictability	The distributional impact of this issue is between parties who pay BSUoS (TG and demand), and those who do not (EG). This is captured under the voltage level differences in operating cost charging (Issue 22). The main impact of this specific issue is on the wider system.
16. EDCM charge predictability	Only certain types of users are exposed to EDCM charges, e.g. large distributed demand and generation users, and therefore this subset are exposed to higher charge variability.

Cost allocation

Table 30 - Distributional impacts of cost allocation issues

Issue	Assessment
17. No clear mechanism for how the costs of enabling platforms are allocated to network users	Some enabling technology costs are charged directly to the connecting customers who benefit while others are socialised among all network users. Due to the small scale deployment of enabling technology this issue does not currently have a significant distributional impact. Based on costs from the UKPN Flexible Plug and Play scheme trial, the capital cost of enabling technology and installation for a flexible connection is around £40/kW[46].
18. No clear mechanism for DSO operating cost recovery	Users in constrained areas of the distribution network and users in unconstrained areas make the same contribution towards operating costs. Due to the small scale role of DSO operation, this issue does not currently have a significant distributional impact, although this is likely to increase significantly in the future as DNOs increase their procurement of operational solutions. An early example is UKPN's flexibility tender[47].
19. Different risk allocation across T and D	The main impact of this specific issue is on the wider system (allocation of risk), where this is assessed as Medium materiality.

Discrepancy in Interface Charges

Table 31 - Distributional impacts of interface charge discrepancy issues

Issue	Assessment
20. Different depths in connection charging across T and D	Distribution network users may face relatively higher connection costs when requesting connection in their preferred location, as they are liable for reinforcement costs that are required to accommodate the connection up to one voltage level above, compared to transmission network connections. However, evidence to date shows that users are infrequently accepting connection offers when wider reinforcement is required, with just 5% of distribution connections triggering network reinforcement between 2010 and 2013[48].

[46] Flexible Plug and Play: Close Down Report, UK Power Networks, 2015
[47] https://www.ukpowernetworks.co.uk/internet/en/have-your-say/listening-to-our-connections-customers/flexibility-services
[48] A guide to electricity distribution connections policy, Ofgem, April 2014

	While one-off connection costs to a desired location on the transmission network may average around £20/kW[49], if reinforcement is triggered on connection to the distribution network the corresponding connection charge is likely to be greater than £100/kW, although this can be avoided by connecting in an area with existing spare capacity, or by accepting a flexible connection. In addition, distribution network users that trigger reinforcement of GSP assets face the associated reinforcement cost regardless of voltage level of connection
21. Voltage level differences in network cost charging methodologies	Smaller EG benefits from DUoS charges and Embedded Export Tariffs whereas transmission generation and larger EG contributes to TNUoS, resulting in distributional effects between users at different voltages. Smaller EG does not face TNUoS charges even if located behind an exporting GSP, a charge that varies between £-6/kW to £30/kW (not including the residual element). A more in-depth comparison between voltage level charging differences can be found in Table 18.
22. Voltage level differences in operating cost charging methodologies	Smaller EG do not face BSUoS charges and in addition receive an avoided supplier BSUoS charge benefit, resulting in higher costs for other users. We estimate that if smaller EG faced BSUoS charges in 2016 the average annual BSUoS charge would have been around £2/MWh, down from £2.31/MWh. This would equate to an annual cost to small EG of around £3/kW, and a cost saving to transmission generation of around £1.3/kW. If solely considering the portion of BSUoS charges due to constraint management costs (around 30% of total BSUoS charges recovered) then the annual cost to small EG equates to around £0.9/kW, and a cost saving to transmission generation of around £0.4/kW.

[49] Open Networks Project: Charging Scenarios report, Energy Networks Association, August 2017

Appendix B Quantitative approaches

Our approach to developing supporting quantitative metrics in each area is set out below.

B.1 Deployment metrics

Relevant evidence used for our deployment metrics includes evidence of existing queues, at distribution and transmission networks, as well as the potential for future delays. At transmission, we have used data from National Grid's Timely Connections Reports[50] to quantify the size of the queue. The queue is defined as connections which receive a connection date offer later than their requested date. At distribution for generation, Ofgem collated the size of the queue under the Unlocking the capacity of the electricity networks[51]. The queue is defined as the volume of capacity which has accepted a connection offer but is yet to connect to the network. For distribution at demand, there have been isolated instances of demand being prevented from connecting due to lack of GSP capacity but the potential for rapid uptake of LCTs could present a much larger issue in the near future. National Grid Future Energy Scenarios (FES) are used provide a possible range of deployment scenarios for LCTs which, based on levels of deployment which require network intervention seen in innovation trials, can indicate when delays to uptake would become likely.

B.2 Efficiency of operations metrics

Efficiency of operations metrics have been narrowly defined to the current inefficient operation of the system, due to signals (or the lack of) creating distortions in dispatch decisions, to avoid an overlap with efficiency of investment impacts. Existing evidence used to quantify these metrics includes constraint management costs at transmission, out of merit dispatch of EG due to current value of Embedded Export Tariffs, inefficient curtailment of flexible distribution connected generation, and excess restive line losses at distribution.

B.3 Efficiency of investment metrics

Our efficiency of investment metrics follow a common approach of using National Grid FES to provide a possible range of deployment scenarios for generation and demand and inferring the subsequent network investment costs required to accommodate them. Where possible we have sourced or calculated incremental network expansion costs, using National Grid's Transport and Tariff model for transmission costs and UKPN's CV101 and CV102 tables for distribution. This allows us to project network costs out to 2040 and using existing evidence for achievable improvements in investment efficiency, e.g. due to peak shifting of LCT demand through managed charging, estimate the capturable avoided network investment costs on a NPV basis.

[50] https://www.nationalgrid.com/uk/electricity/industrial-connections/registers-reports-and-guidance
[51] Unlocking the capacity of electricity networks (associated document), Ofgem, February 2017

B.4 Allocation of risk metrics

We have quantified the allocation of risk metrics for the lack of predictability of charges. The approach taken to this, including EDCM DUoS, TNUoS and BSUoS charges, is to firstly measure the risk due to the unpredictability of historical charges and secondly assume that parties must hold capital to cover variations in charges which, by defining a cost of capital (assumed to be 8%), results in an additional cost to the party facing the charge.