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# Transmission network charges – discussion note


**Summary**

Within our Access and Forward-Looking Charges significant code review (Access SCR), we are undertaking a focused review of forward-looking transmission charges (also known as transmission network use of system (TNUoS) charges). Specifically, we are reviewing:

- Forward-looking transmission charging design for demand users.
- Forward-looking transmission charging design and access arrangements for distributed generation.
- The "reference node" used in the model used to calculate transmission charges.

This note describes the current approach to transmission charges for demand users and for distributed generation and an assessment of the potential options for addressing a number of key issues with the arrangements.

We are concerned that the existing forward-looking transmission charges for demand users may not be reflecting the key transmission cost drivers. We are considering whether other options to the current "Triad" approach could support better outcomes. This includes changes to provide advance notice of when the peak charging period will be, setting fixed charging time bands at the start of each year, or moving to charges based on a user's agreed capacity, ie the right they have to import from the network.  These options provide different levels of signal for demand response. We will consider whether demand response signals are needed, or whether these signals are more efficiently delivered elsewhere.

The existing arrangements for access to and charging for the transmission network vary for different sizes of generators. We are concerned that this could be distorting competition and leading to higher system costs for consumers. We are considering whether small distributed generators should start paying towards wider transmission charges in areas where they contribute to network costs. One option for this could be to continue to treat them as negative demand and charge them for output during peak charging times. Alternatively, they could be charged based on their agreed capacity. We are also considering options so that distributed generators pay local transmission charges where these are relevant.

We are also considering options for how both demand and small distributed generators could have their access rights to the transmission network defined explicitly. This would be needed to support agreed capacity charges. These could be agreed either directly with the Electricity System Operator (ESO), or via third parties such as suppliers.

We are also considering whether a technical aspect of the transmission charging model (the calculation of the "reference node") may be leading to different incentives for different kinds of users. We intend to undertake further analysis on the extent to which this is an issue.

This paper represents our initial views on the issues and options, as well as the links between them and the possible trade-offs we may have to consider.

1.1. This note is set out as follows:

- Section 1: The current approach to transmission charges
- Section 2: The issues with the current arrangements
- Section 3: An overview of the possible options for change
- Section 4: Our preliminary views and cross-cutting policy considerations
- Section 5: A summary of our preliminary views and next steps.

1.2. Users of the transmission networks in Great Britain (GB) face transmission charges. These cover the building, maintenance and operation of the transmission system.

1.3. We are considering whether the existing approach to transmission demand charging, which dates back over a quarter of a century, is providing the right signals to users and properly reflecting the costs of the networks.

1.4. Generators that are directly connected to the transmission network, or are treated as such, are also charged for their use of the system. Smaller generators connected to distribution networks or on users' sites, face different charges based on the demand charging arrangements, and do not have explicitly defined access rights. As a result, there are a number of areas of difference between the way that larger and smaller generators are charged.

1.5. We have concerns that the separate arrangements may be leading to different incentives across user groups, and that this may not be in consumers' interests. The incentives and signals provided to users are crucial for securing a least-cost energy transition and an effective market for consumers.

1.6. We are also considering whether targeted changes to the charging models is likely to produce a more efficient outcome for consumers. We are reviewing these arrangements as part of the Access SCR.

## Section 1 – The current approach to transmission charges

1.7. Transmission charges exist to carry out two functions. Firstly, forward-looking or cost-reflective elements are designed to allow users to understand the impact of their use of the network and make efficient choices. The second category, residual charges, are designed to ensure the overall allowed revenues of the networks are recovered. For the purposes of this paper, where we discuss transmission charges, we mean the forward-looking charges, rather than residual and cost recovery charges. Both transmission and distribution residual charges have been the focus of our Targeted Charging Review (TCR). Balancing services use of system (BSUoS) cost recovery charges are under review by the Balancing Services Charges Taskforce.

1.8. The Transport model is used to calculate forward-looking transmission charges for demand and generation. This model, and the arrangements for charging demand and small distribution-connected generation[1] (SDG), date back to the early 1990s. There have been a number of reforms to transmission charging in recent years. Charges for transmission-connected generation (TG) and larger distribution connected generators (LDG) received comprehensive updates to the forward-looking charges through Project TransmiT[2] and

[1] SDG are generators with installed capacities of below 100MW that are connected to one of the distribution networks, rather than connecting directly to the transmission network. These users are currently treated as negative demand, rather than generation.
[2] More information can be found on the TransmiT page of our website.
https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit

subsequent modifications, and reform to the residual charging regimes taking place through the TCR and embedded benefit reform.[3]

1.9. The existing charging arrangements covers all demand users, with suppliers charged based on either the half-hourly demand of their larger customers during system peaks, or based on the year-round consumption of their smaller customers. For generators, the arrangements apply differently to the following broad categories of users:

- TG, which face wider locational transmission charges[4] and local transmission generator charges,[5] which cover the parts of the network that link individual user connections to the Main Interconnected Transmission System (MITS), the highly meshed central part of the transmission network.

- LDG (distribution-connected generation with installed capacities above 100MW), which face wider locational transmission generation charges;

- SDG, which face transmission charges (via their supplier) as inverse demand, with their output netting off demand in their region; and

- Behind the meter generation (BTMG), also known as onsite generation (OSG) and demand side response (DSR), who also face transmission charges (via their supplier) as inverse demand, with their output or demand reduction netting off demand on their sites. When exporting from their site, BTMG faces the same signal as SDG.

1.10. There are other differences between the regime for TG and other generation and demand users. This includes that whilst TG and LDG do have explicit access rights to the transmission network (via their transmission entry capacity, or TEC), SDG and demand users do not have these rights by default. SDG do have the ability to enter into specific agreements with the ESO that provide them with access rights. We consider some of these issues to

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[3] Embedded benefits refer to the differences in treatment of SDG with installed capacities of below 100MW when compared to the arrangements for LDG and TG. They have historically provided an incentive to site generation at the distribution level due to lower charges or increased generation benefits. In recent years, we have addressed several Embedded Benefit related distortions, in particular through the CMP264/5 modification and the TCR.

[4] Wider locational transmission charges reflect the impact of a generator on the MITS the core highly meshed part of the transmission network.

[5] Local transmission generator charges cover the parts of the network that are not part of the MITS and link individual user connections to the MITS. They can be shared, or used only by single users.

require further investigation and possible reform. A brief summary of the current arrangements is included in the below table. For a fuller description of the arrangements, see the annex on Current Arrangements.

*Table 1: summary of existing transmission arrangements*

| Area | Existing transmission arrangements |
|---|---|
| **Forward-looking transmission charging design for demand users** | • Suppliers face charges for their larger demand customers based on Triad charges, a demand charge levied on a £/kW basis on their usage in three periods of high system demand.<br>• Charges vary across GB reflecting whether generation or demand are expected to increase or reduce the need for investment in those areas.<br>• Charging periods are not known in advance, leading customers to manage their demand at times when high demand is expected.<br>• Small demand users with non-half hourly settled meters pay location specific volumetric charges on their volumes between 4pm and 7pm throughout the year.[6] |
| **Forward-looking transmission charging design and access arrangements for distributed generation** | • Access rights vary for different sized generators. For the majority of distribution-connected users, their access rights do not explicitly define their ability to access the transmission network.[7]<br>• Where a generator seeking to connect to the distribution network may have an impact on the transmission network, the Statement of Works process[8] requires an assessment of the likely impact on the transmission system.<br>• In comparison, TG and LDG agree their required TEC directly with the ESO.[9] |

[6] This is based on their estimated consumption during 4-7pm, applying an average consumption profile to their annual consumption figures
[7] Some SDG can agree the ability to export to the transmission system – through a Bilateral Embedded Generator Agreement (BEGA), which provides them with formal TEC, or may have a Bilateral Embedded Licence Exemptible Large power station Agreement (BELLA), as applicable.
[8] When a Distribution Network Operator (DNO) receives a request from a generator intending to connect to the distribution network, which it believes will have a significant impact on the transmission system, it is required to engage with the ESO, in conjunction with the relevant transmission owner (TO). The ESO and TO will perform some analysis to determine whether the new connection would be expected to have an impact on the transmission system that would require investment. This is known as the "Statement of Works" process. More information can be found on each of the DNOs' websites.
[9] LDG requiring TEC can enter into a BEGA with the ESO, though they will also require a corresponding connection agreement with the relevant DNO.

| Area | Existing transmission arrangements |
|---|---|
| | • Exports by SDG face the inverse of this signal, though they have charges that are capped at zero[10] to prevent them having to pay charges to operate at peak, so they don't have an incentive to turn off during this period. This and other issues mean charges for SDG broadly, but not exactly match signals faced by LDG. All distributed generation do not currently pay local charges. |
| **The "reference node" used in the model used to calculate transmission charges** | • The Transport model calculates the incremental cost of transmission from and to different areas, by modelling the 900+ nodes and 1400+ circuits on the transmission network under two different system conditions.<br>• Each node is given a cost by adding an additional MW of power to a node and assessing the overall change in flows on the system, with these outputs grouped and converted to an annuitised infrastructure cost. The additional MW needs to be removed to allow a balanced system. Where this MW is removed, it has an impact of the flows on the system and on the relative proportions of revenue recovered from generation and demand.<br>• At current, the reference node is a "distributed demand node" where a fraction of demand is taken off all other nodes to allow the system to balance. |

# Section 2 – The issues with the current arrangements

1.11. There are three main areas within the transmission arrangements which we are considering through the Access SCR and they are discussed in this section.

**Forward-looking transmission charging design for demand users**

1.12. We are concerned that the existing charges for demand users, which focus the forward-looking charge on users' consumption during the system peak periods, may not accurately reflect how users' actions are impacting future network costs. Peak demand on the system as

[10] We have previously described this mechanism as the "floor at zero". We use the term "capped" and "charging cap" in this document as we think it more simply conveys that generators charges are limited or reduced in areas where they would otherwise be higher.

a whole appears to be a less important driver of transmission costs in many areas, and we consider that charging on this basis may lead to inefficient outcomes.

1.13. The Transport and Tariff models[11] produce charges that provide long-term locational signals to users via different charges in each region. These signals reflect the cost or benefit of additional demand or generation in each location. It also provides operational signals, as users are incentivised to manage their demand or generation output to minimise demand transmission charges or maximise SDG credits at times which they think could be a Triad period. This system provides broad signals in periods of expected high system demand. However, meeting the requirements of the system in periods of high demand is only one function of the network. Increasingly, other system conditions drive transmission costs, such as periods of low demand on the system and periods of very high renewable output. Charges that focus only on periods of high demand may not lead to behavioural responses of most value to the system, and may lead to the development of user behaviours or investment that respond to lower priority network cost drivers and not those that drive the most cost.

1.14. In a future system with more intermittent generation, and smarter, more flexible demand, it is possible that different areas of the network may face different cost drivers. The provision of peak capacity in winter may remain a key driver in urban and industrial areas, for example, and so charges that focus on demand reduction at peak may continue to be desirable in these areas, though the periods in which these peaks fall may differ from region to region. It may also be the case that periods of regional peak system flows, rather than overall peak demand, are better reflections of individual region cost drivers and are more effective at signalling to demand to use the system at times of high generation output.

1.15. Demand is not currently thought to be a significant driver of transmission costs, as set out in the May 2019 Charging Futures Report on Network Cost Drivers, though in future, increased electrification of heat and transport and the wider transition to a net-zero economy is likely to lead to substantial demand increases. We should consider future potential network conditions when assessing whether demand reduction signals are needed. Charges that are based on usage at different times need to be sufficiently accurate in reflecting when peak network conditions occur otherwise they risk distorting operational decisions, and would need

[11] The Tariff model converts the Transport model outputs into charges for users.

to be adaptable so that they can respond to changes in when those peak conditions occur in the future.

1.16. Following our TCR decision this year, residual charges will no longer be recovered using the Triad system and, as a result, the signal to provide demand response will be weaker. We would expect users to respond to Triads in line with their lower, forward looking value, and as such, demand response volumes may be lower.

1.17. Not all types of transmission charging frameworks send demand response signals. For example, agreed capacity charges provide only locational investment signals, informing users' decisions about where and what to invest in, but not when to use the networks. Additional operational signals would be needed, such as those sent via ESO flexibility procurement. This model could be more accurate in being able to signal network peaks and able to change over time as the nature of those peaks change, but would be reliant on more parties – including small demand parties – being able to access those markets effectively.

**Forward-looking transmission network charging design and access arrangements for Distributed Generation.**

1.18. The existing arrangements for access to and charging for the transmission network vary for different sizes of generators.

1.19. TG currently have explicit access to the transmission network and directly pay two forms of forward-looking transmission charges:

- **Wider locational transmission charges** are intended to reflect the incremental costs imposed by the generator on the wider transmission network (called the MITS). This element can be positive or negative. It is negative in locations where a generator effectively reduces costs by reducing the need to flow power over the transmission network.
- **Local transmission charges**, where they apply, cover an estimate of the incremental costs related to the local circuit and substation imposed by the generator.

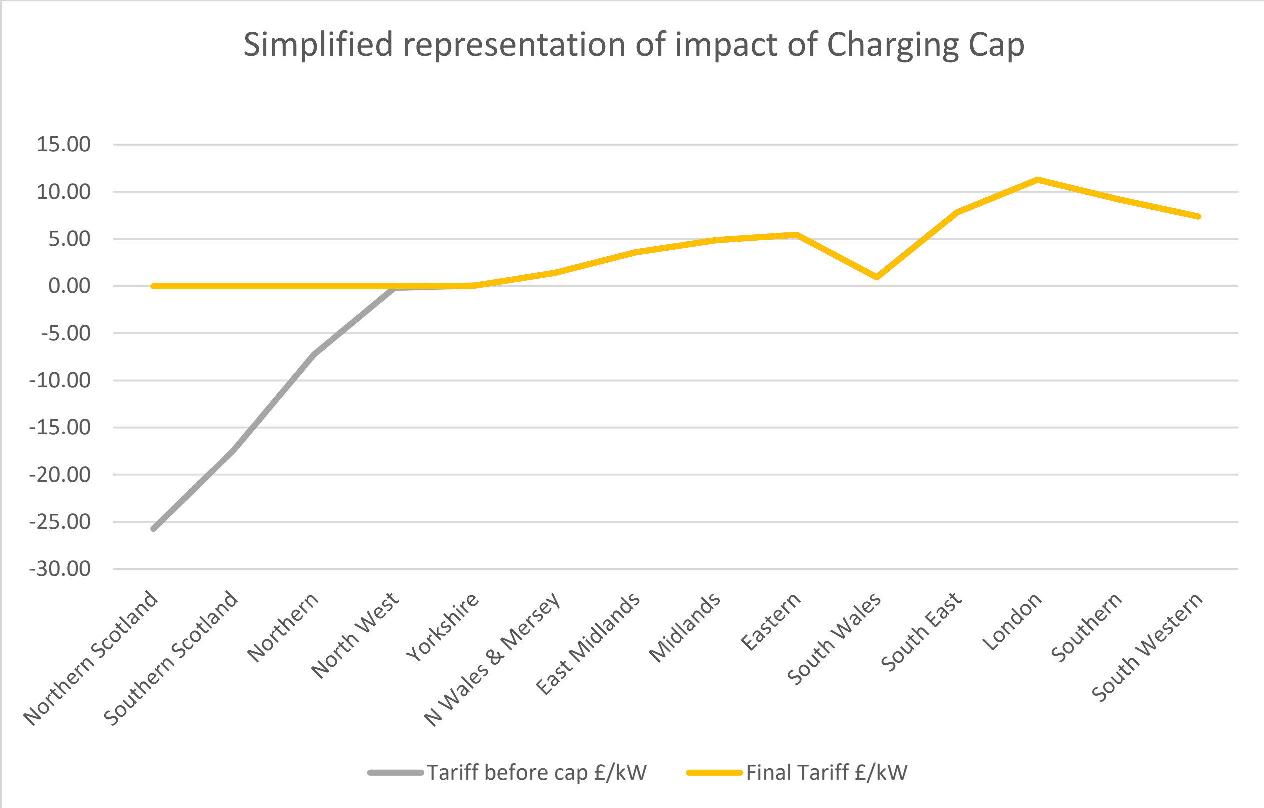
1.20. LDG also have explicit access to the transmission network and pay the same wider locational transmission charges as TG. SDG do not have explicitly defined transmission access, and face the inverse of the wider locational demand charge, which is capped at zero, as discussed above. Neither LDG or SDG face an equivalent local transmission charge.

*Wider locational transmission charges*

1.21. Although they are connected at distribution-level, SDG still impact flows across the transmission network. In an area where there is more generation than demand, any new generation in that area will lead to increased flows over the transmission network as more electricity needs to be exported to demand in other areas. This remains the same whether the generation is connected at transmission or distribution level. SDG can also reduce transmission network constraints when they locate in areas where demand exceeds generation, and they do currently receive transmission credits in these areas.

1.22. The effect of the cap, which was introduced to prevent SDG from facing a signal to reduce output at peak times, is currently limited to a minority of zones. As shown in the below chart, four charging zones are currently affected, though one of these faces only a very minor adjustment. The Northern DNO region, which covers the Northeast of England, receives a moderate adjustment, with a dampening of charges of around £7/kW against the modelled cost reflective level. Both demand zones in Scotland receive significant adjustments, significantly dampening the locational signal received by generators in these zones, when compared to the modelled cost reflective charge.

***Figure 1: Locational SDG charges before and after application of charging cap (2020/2021 forecast, £/kW)***




*Source: National Grid*

1.23. We intend to consider the case for better alignment of SDG charges with those of large generators (i.e. TG and LDG). This could reduce transmission network costs by improving signals for all generators to locate where they can reduce network costs. This can also reduce distortions to competition between generators connecting at different network locations and support more efficient whole system outcomes.

1.24. As part of this review, we intend to gather further evidence on the extent to which these differences amount to an undue barrier to effective competition that are causing distortions and so leading to higher system costs than necessary. We will also consider whether the charging cap provides any benefit to security of supply.

*Local transmission charges*

1.25. Currently, distributed generators are not required to contribute to local transmission assets that connect their network to the MITS. In future, we expect situations where local assets are used by distributed generators may be commonplace, and it is important that fair non-discriminatory arrangements are in place to protect competition and ensure investment takes place in an efficient way.

1.26. In most situations, distribution networks are connected directly to the MITS, so that, if power from distributed generation is being exported over the transmission network, it will flow over the MITS. As such, the cost of using that network would be reflected through the wider locational transmission charge.

1.27. However, we are aware of some situations in remote areas of GB where distributed generation could be driving reinforcements to the transmission network that would not be part of the MITS, such as the proposed subsea cable to Orkney to support new renewable generation projects. In such cases, distributed generation can be a key driver for the need for substantial extension of the transmission network but would not currently face local transmission charges in the same way that TG would.

1.28. We think this risks distorting competition between generators, meaning that some projects are developed as they do not face equivalent charges to others, rather than because they are more efficient, taking into account network costs as well as other benefits. We consider that competition on a level playing field, with generators facing the full costs (including network and carbon) and benefits (for example, including the benefits of higher load factors for wind farms in remote areas) of their project, is likely to drive lowest system costs for consumers. We intend to assess the case for introducing local transmission charges for distributed generation where relevant further, including consider how it could work in practice.

**The "reference node" used in the model used to calculate transmission charges.**

1.29. The existing Transport model includes a number of assumptions and processes that have an impact on the charges produced. The model calculates the incremental impact of adding an additional MW of generation or demand at each node on the network. To do this it needs to make an assumption about the reference node – the offtake point for additional power added to the modelled system. The location of this point or, where it is a number of points, the approach used to allocate power to various points, leads to differences in the electrical flows that are modelled. As a result, the choices here can change the costs allocated to different users. The existing arrangements were established during Project TransmiT. We intend to review these arrangements to ensure they are promoting competition and appropriately reflecting expected network costs.

1.30. The impact is that overall revenues from the locational demand charges sum to zero, whereas the revenues from locational large generation charges are positive. We think that this could potentially be distorting competition between those providers who face negative demand charges (such as DSR providers and onsite generators) and those who face positive generation charges. We intend to undertake further analysis on the extent to which this is an issue.

# Section 3: An overview of the possible options for change

### Forward-looking transmission network charging design for demand users

1.31. In our summer working paper, we set out our initial views on reform options for forward-looking transmission demand charges. The reform options considered were broadly grouped as:

- Reform to the use of Triad for forward-looking transmission charges for demand[12] (which is a form of critical peak pricing), through potential improvements such as:
  - a move to ex-ante charges where charging periods are known in advance
  - additional periods, to spread charging signals over a greater number of hours.
- Replacement of the Triad model (for forward-looking charges) with an agreed capacity approach
- Replacement of the Triad model (for forward-looking charges) with a system of static time-of-use charges, delivered through capacity or volumetric charges.

1.32. We are continuing to consider these options. Other potential reform areas that could be combined with the above options include:

[12] Triad is also used for the residual element of transmission charges for demand, which is being changed via the TCR.

- Having the critical peak or time-of-use charging periods vary in different locations on the network (such as different Triad periods in one region to reflect the investment drivers in that region)
- Charges that better reflect that different system costs are driven under different conditions (such as charges that reflect peak use and other charges that reflect periods of high renewables output or low demand).

1.33. Below we discuss the principles underlying potential reforms and present some potential policy options. We intend to further elaborate on these and engage stakeholders as the options are better developed.

*Transmission cost drivers and the cost reflectivity of charges*

1.34. The existing transmission charges incentivise users to provide behavioural response at system peak events, and were set up when the system was dominated by centralised, dispatchable generation and the highest winter peak was a key driver of the size of the transmission system.

1.35. However, as discussed in paragraph 1.13, analysis from the ESO and TOs suggests that, as we move to a more decentralised, low carbon and intermittent generation mix, transmission costs are increasingly driven by other factors – such as summer minimum demand periods and periods of high renewables output – which are less likely to coincide with the periods in which peak system demand occurs. It is also likely that the periods of peak flow on the network will increasingly differ across different locations/regions, given different generation mixes.

1.36. We aim to undertake further analysis of the extent to which peak demand remains the most relevant means to charge users, for example by assessing the extent to which national peak demand correlates with local network peak flows, and whether alternatives are feasible or desirable.

1.37. If national and local peaks are well correlated, and peak demand remains a good proxy for the system use that drives transmission network investment, the retention of charges based on system-wide peak demand may be the most appropriate option. Below we consider briefly some pros and cons of each option against our guiding principles.

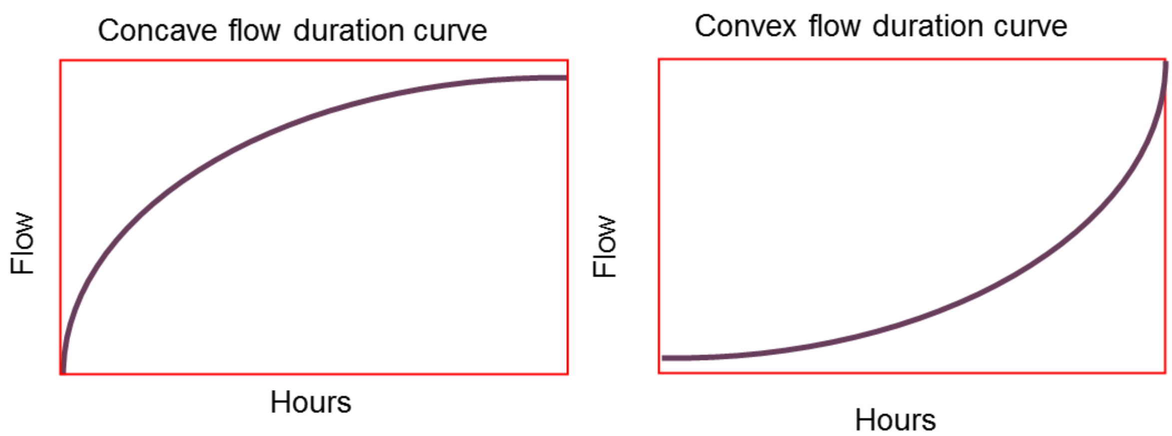
*Table 2: Summary of assessment of peak demand options*

| Available options | Option description | Arrangements support efficient use and development of system capacity (Efficiency) | Arrangements reflect the needs of consumers as appropriate for an essential service (Essential service) | Any changes are practical and proportionate (Practical and proportionate) |
|---|---|---|---|---|
| **National Peak Demand / Flow** | Charges set at peak demand, which on system level is same as peak flow | Efficient where national peak correlates with peak local flows | More predictable | Simple, low change, centralised |
| **Local peak Demand** | Charges relate to local demand peaks | Not likely to be useful, as local peak demand may not align with generation outputs | Less predictable | Depends on granularity. More complexity. |
| **Local Peak Flow** | Charges relate to local flow peaks, which may be generation rather than demand | Efficient if local flows do not correlate with national peaks. Dependent on granularity. | Less predictable, more complicated. | Decentralised forecasts, more change, and more complexity. |

*Merits of different forms of time of use charges*

1.38. The existing Triad arrangements (an ex-post critical peak charge) achieve a broad flattening of system peaks as there is uncertainty around when system peak demand will occur. As the charging periods are determined ex-post, users have an incentive to adjust their behaviour to reduce their potential charges in all periods they might reasonably expect could be high demand periods for which they might receive a charge. If, by user action, the period that would have been the highest demand returns a lower demand, the peak moves to another period.

***Figure 2: flow duration curves***




*Source: Frontier Economics*

1.39. The above flow duration curves represent, respectively, a pattern of network flows where there are a large number of similar peaks (a concave flow duration curve) and a flow patter where there are a smaller number of very distinct peaks.

1.40. The existing Triad method may be more appropriate where there is a broad range of similar peaks, or where the likelihood of a correct forecast of a small number of large peaks is quite low. From a users' perspective, the uncertainty of when a charging period will be increases the number of periods in which they may change their behaviour to minimise their possible charges. At the same time, as the number of chargeable periods does not increase, the signal does not become weaker as it would if more ex-ante periods were designated – users are highly incentivised to react in periods they expect could be Triads, as the cost if they do not reduce their demand during a Triad period is substantial. This can help if the charging period accurately reflects network cost drivers, but could entail significant distortions to user behaviour if not and creates significant financial risk for users.

1.41. This user incentive may be considered more market-based and less centralised, with users taking on the risk of forecasting the peaks. This does have some drawbacks. For example, unengaged users may not know to reduce their demand and may not have an understanding of the sorts of periods that are likely to present highest demand, and also that the uncertainty may add complexity and dispatch distortion over a broad range of periods.

1.42. For an **ex-ante critical peak charge**, the effect is different. If a peak charging period is notified in advance, users have the incentive to change their behaviour to reduce their charges only during the notified periods. If this action reduces the size of the peak enough, the notified periods that were expected to have the highest demand may end up being lower the next highest peaks that are not charging periods. In this instance, unlike the ex-post model, the chargeable peak period will not move.

1.43. This could be less useful in reducing network cost drivers if the highest peak that is not a charging event is still very close to network capacity levels (ie there is a concave load flow duration curve). In such a situation, an ex-ante critical peak charging approach would need to introduce more peak charging periods to have more confidence that behavioural response would be achieved in all periods where the network may be constrained. In contrast, a small number of peak charging periods would be more appropriate if there is a convex load flow duration curve, such that the next highest peak that is not a charging period is going to be less of a concern for network capacity.

1.44. For this reason, it seems that an ex-ante critical peak charging approach is more likely to be more appropriate for managing a small number of very high peaks, and where the possibility of an accurate forecast is high. We consider that as the number of peaks increases, it becomes more akin to a seasonal static time-of-use approach. This would have the benefit of being a simpler approach, and is discussed further below.

1.45. In an ex-ante critical peak charging model, the body designating the peaks is taking on the risk of forecasting, rather than users. Centralised bodies may be better equipped to forecast local peaks, as users may not have access to this information and local demand or generation forecasts may be less reliable than nationwide demand forecasts. This approach would reduce risk to users that they mis-forecast when a peak charging period will occur, and also can reduce the extent to which users change their behaviour when it is not needed to help manage the network.

1.46. As noted above, **static time-of-use charges** could have more merit where network peaks are flatter and more consistent and could be simpler and more accessible for users. We consider a seasonal time-of-use charge is more likely to be able to reflect different network cost drivers. For example, peak charges could only be high during a particular season (eg winter). Alternatively, there could be different rates and times of peak charge events across seasons – such as demand could pay charges during evening peaks in winter but receive credits during day-time minimums in summer (eg where additional demand in certain areas –

such as electric vehicles (EVs) charging then – could help reduce peak flows on the network caused by exporting solar farms).

1.47. The increased number of peak charging periods under a static time-of-use approach would mean the per unit charge for usage in each period would reduce, lowering the incentive for users to respond in any given period. However, it would provide a clear signal to users about the value in investing in equipment that will allow them to reduce their demand consistently during the peak charging periods.

1.48. If the benefits of a critical peak model (such as providing an incentive to reduce demand at specific times) are considered small or overly distortive, a model with many more charging periods, such as static time-of-use or agreed capacity may be more suitable. Time-of-use options could provide broader signals for demand response, and agreed capacity no signal at all (other than discounts that could be available to users if they chose more flexible access rights, such as non-firm/curtailable access). These options present users with less complexity and greater predictability and, due to weaker incentives, may provide a lower level of distortion in a greater number of periods.

*Charging model - Time of use vs Agreed capacity approaches*

1.49. An agreed capacity charge is different from the time-of-use charges in that it does not send an operational signal to users about when the network is likely to be constrained. This can have advantages if there are concerns that the time-of- use signals bring significant risk of incentivising behavioural change at times when the network is not actually constrained, which could increase users' and wider system costs without the corresponding benefit of reduced network costs.

1.50. Agreed capacity charges do have drawbacks, not least that demand and SDG do not currently have agreed rights to use the transmission network, which means that this option would need these rights to be defined. We discuss the issues with this further below in respect to SDG's access to the transmission network (see paragraph 1.60). There is also a need to consider how agreed capacity charges would capture the differing impacts of different types of users on the network, as was reflected in the changes to large intermittent generators' charges that we made through Project TransmiT.[13]

1.51. We are considering the extent to which we think transmission charges should be a means by which we send operational signals to encourage users to flex their network usage, using the criteria set out in our discussion note on the procurement of flexibility in our first working paper.[14] Historically, the need for flexibility has been signalled via the ESO procuring balancing actions from larger generators. Increasingly, these services are provided by smaller generators and demand users as the ESO opens balancing markets. However, it may be harder for these players to engage with these markets, whereas flexibility signals through network charges are readily accessible for most users.

**Options to reform forward-looking transmission charges and access arrangements for distributed generation**

*Wider locational transmission charges*

1.52. As set out previously in this paper, despite recent changes, SDG currently face significantly different arrangements to large generators. Aligning SDG's charging arrangements with those of large generators would ensure that all generators receive the same forward-looking transmission charges, meaning that they would receive credits in zones where they are expected to reduce long-term transmission costs, and pay charges in zones where they are expected to increase long-term costs. We have initially considered three options for this:

1. Retaining the cap on SDG wider locational charges at zero
2. Removing the cap while retaining the use of inverse demand charges for SDG
3. Removing the cap and moving to agreed capacity charges for SDG

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[13] Project TransmiT brought about reforms to transmission generation charging that better reflect the different costs brought to the system at times of peak demand (the Peak Security element of Wider transmission charges) and at times of year-round renewable generation flows (the Year Round element of Wider transmission charges). It also better took account of the contribution of technology type and load-factor to costs.

[14] https://www.ofgem.gov.uk/system/files/docs/2019/09/summer_2019_-_working_paper_-_links_with_procurement_of_flex_note_final_nd.pdf

We intend to further elaborate on these and engage stakeholders as the options are better developed.

Retaining the cap at zero for SDG vs removal of the cap

1.53. For the reasons outlined above, our initial view is that the cap has the potential to present a significant distortion, particularly in the two Scottish demand zones. We intend to assess the potential efficiency savings against potential impacts, including low-carbon generation impacts, and would only take action if we were confident it would support helping achieve decarbonisation at least cost.

Retaining the use of inverse demand charges vs moving to agreed capacity charges

1.54. A benefit of continuing to use inverse demand charges is that it would retain the current approach, with suppliers billed on behalf of their SDG customers based on data that is already available. However, as was recognised when the cap at zero was introduced, a risk with charging SDG based on inverse demand charges is that they would have the incentive to turn down during Triad periods to reduce their charges. As currently Triad periods are the periods of highest winter demand, it is unlikely to be desirable from a security of supply perspective to be encouraging generation not to output at these times. Some of the other options being considered for transmission demand time-of-use charges could mitigate the extent of this risk.

1.55. Under an agreed capacity approach, SDG would not face any operational signals. This could mitigate security of supply concerns, but could also mean that flexible SDG are not able to receive the value they can provide in managing network peaks, unless the ESO's flexibility markets are sufficiently accessible (as discussed above).

1.56. Following the current approach to agreed capacity charges for large generators, where adjustments for load factor and technology type are made, may be preferable for SDG relative to inverse demand charges, as they could reduce the charges payable. This would help fully align SDG and large generators' wider locational charges. However, there would be a need to consider how to apply these rules, given the current application for large generators uses individual generator load factors, which may have practicality and proportionality challenges if applied for SDG.

*Distributed generation charging for local transmission charges*

1.57. Our initial view is that ensuring that all generation users contribute toward local charges, in the limited circumstances where distributed generation make use of local circuits, would remove potential embedded benefits that might arise and improve competition, reducing whole system costs.

1.58. However, we recognise this might involve SDG – including renewable projects such as onshore wind farms – paying more. We will consider whether the impact of these changes is justified by more efficient location decisions. While the areas concerned are likely to be limited to the Scottish islands initially, it is possible it could apply to other remote areas in time.

1.59. We recognise a significant number of interactions with other policy areas, including reviews of the generation and demand zones, and of the MITS rules, and discussions around the EU €2.5 charging cap,[15] the reference node, the SDG cap at zero for wider locational charges and the connection boundary. We invite stakeholders to bring any additional links to our attention, particularly where they relate to sustainability and system transition.

*Access arrangements*

1.60. There would also be a need to consider how SDG's transmission access capacity could be agreed, and who would be responsible for charging them, given they currently have no direct relationship with the ESO. One option would be for them to agree new rights individually with the ESO or agree them via a third party, such as a DNO or a supplier.

1.61. Individually held rights may require users to enter into agreements such as BEGAs or BELLAs,[16] and/or become signatories to agreements such as the Connection and Use of System Code or the Balancing and Settlement Code, but may also be achieved in other ways.

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[15] Commission Regulation (EU) 838/2010 laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32010R0838

[16] Such as a Bilateral Embedded Licence-exemptible Large power station Agreement (BELLA) or a Bilateral Embedded Generation Agreement (BEGA). Users with BEGAs are currently the only SDGs with defined access arrangements to the transmission system, as this agreement provides specific use of system rights and Transmission Entry Capacity (TEC).

For rights held via a DNO or a supplier, one option could be for them to be based on the users' agreed capacity levels for the purposes of distribution charging.

1.62. If the ESO were to agree the rights and charge them directly, it could mean a substantial increase in administration costs, as they currently have no contractual relationships with SDG and it would substantially increase the number of parties it would need to charge. We intend to consider the practicality and proportionality of these options further.

1.63. We also intend to consider whether the existing differences in access rights between types of users amount to a barrier to competition or harmful distortion from a consumer perspective. As noted above, we will also be considering these issues for transmission demand users.

**The "reference node" used in the model used to calculate transmission charges.**

1.64. More investigation is needed into the potential benefits and impacts of change to the reference node. We have set out some indicative high-level options in the table below. We intend to consider the practicality of the different options within the Transport model, particularly whether there could be some form of hybrid option, and whether any of the options would be more likely to bring efficiency benefits through reducing distortions, or whether effects would be distributional in nature only. We will also consider the potential merits of some of the options for change having regard to the risk that in future average transmission generation charges could exceed the maximum allowed €2.50/MWh.[17]

***Table 3: options for reforming the reference node***

| Option | Option description |
|---|---|
| **No change** | Retain the existing distributed demand node, where system costs are calculated according to generation's cost to deliver power to the computed centre of demand, recovering more revenue from generation |

[17] In assessing this, we will take into account the potential impact of the proposed CMP317 modification, our TCR decision to remove the Transmission Generation Residual payment and the potential impact of options to remove the cap at zero for wider locational SDG charges. CMP317 is the modification looking at the definition of connection assets to be used when considering whether generation charges fall within the range allowed by EU regulations. More information can be found here https://www.nationalgrideso.com/document/144516/download

| Option | Option description |
|---|---|
| **Recover more from demand** | Reform the model to incorporate a "distributed generation reference node", where system costs are calculated according to the cost to transmit power away from a computed centre of generation, recovering more revenue from demand. |
| **Hybrid** | An option that seeks to find a middle ground between these two options. |

# Section 4. Our preliminary views and cross-cutting policy considerations

### Forward-looking transmission network charging design for demand users

1.65. Below we present initial views on some of the potential options for reform.

*Table 4: summary of assessment of options for demand users*

| Option | Option Description | Efficiency | Essential service | Practical and proportionate |
|---|---|---|---|---|
| **Ex-post (Improved Triad)** | Retain ex-post approach, more granular charges, possibly targeting flow | Improved if aligned with peak flow periods of network cost. May be better with regional variation in peaks | Less predictable, similar to status quo | Low change, more if regional peaks introduced |
| **Ex-ante critical peak** | Move to ex-ante periods, with peaks designated by ESO or other body rather than forecasted by users | Improved if forecasts accurate. May be better with regional variation in peaks | More certainty for users. Predictable, user friendly | More change as need for ESO to take on forecasting and notification role |
| **Static Time of Use models** | Time-of-use volumetric or time-of-use utilised capacity charges following a "Red- | Less efficient if targeted demand reduction needed, more if broad signals sufficient. May be improved if | Simple and predictable for users | Would require system changes. Simple, can be set out in charging statement or unit rates |

| Option | Option Description | Efficiency | Essential service | Practical and proportionate |
|---|---|---|---|---|
| | Amber-Green" framework | regional variation in peak, though may be less needed given broader spread of peak periods. May be lower dispatch distortion than critical peak charging options | | |
| **Agreed Capacity** | Charges with no operational signals, only locational ones | Less efficient if demand reduction needed, more if signals provided efficiently elsewhere and/or are concerned about dispatch distortion from other options. | Very simple for users. No day-to-day user engagement needed though capacity level must be determined. | Would require system changes and means of identifying access requirements for demand users without relationship with ESO |

**Options to reform forward-looking transmission charges and access arrangements for Distributed Generation**

1.66. Below we present initial views on some of the potential options for reform.

*Table 5: summary of assessment of options for distributed generation*

| Option | Option Description | Efficiency | Essential service | Practical and proportionate |
|---|---|---|---|---|
| **Remove cap and maintain inverse demand charges for SDG** | Remove cap at zero for SDG wider locational charges, with SDG paying charges in northern zones according to their output during triad periods | Broadly cost reflective, efficiency improvements. Potential decarbonisation and security of supply impacts. | No major impacts | Potential for increased costs for some generators, practical issues surrounding charging these users. |
| **Remove cap and move to agreed capacity charges for SDG** | Remove cap at zero for SDG wider locational charges, with SDG paying charges in northern zones according to their agreed access to the transmission network | Most cost reflective, efficiency improvements. Potential decarbonisation impacts. | No major impacts | Potential for increased costs for some generators. Could involve significant new administrative costs, though some options could mitigate this. |
| **Distributed generation contribution to local assets** | Distributed generation make contributions to local charges where relevant | More cost reflective, efficiency improvements. Potential decarbonisation impacts. | No major impacts | Potential for increased costs for some generators. Could involve additional administrative costs as SDG do not currently have relationship with SDG |

1.67. Moving to an agreed capacity charging approach for demand users and/or SDG would require them to have defined access rights to the transmission network. The table below presents initial views on some of the potential options to do this. This table is not exhaustive and we will consider further possible options if identified.

*Table 6: summary of assessment of options for access arrangements*

| Option | Option description | Efficiency | Essential service | Practical and proportionate |
|---|---|---|---|---|
| **No change** | No changes to access rights definitions. | Less likely to lead to efficient outcomes. Limits charging options available (ie no agreed capacity) positive charges challenging | Status quo, no change | Status quo. May prevent some charging options |
| **Explicit rights via agreement** | Users to agree explicit access | More likely to lead to efficient outcomes as cost-reflectivity improved. May improve visibility of SDG | Clarity around rights. Increased complexity, de Minimis level may be needed for smaller users | Requires users to enter into agreements with new industry parties. Implementation challenges, greatly expanded ESO admin/client base |
| **Explicit rights via third party** | DNOs or suppliers (etc.) nominate access requirement on behalf of customers | More likely to lead to efficient outcomes as cost-reflectivity improved. May improve visibility of SDG | Clarity around rights. Low change for users, De Minimis level may be needed for small users | Requires users to engage with suppliers or others to obtain access, unless just based on their agreed access level for distribution charges. Potentially supplier/DNO role expanded, forecasting required |

1.68. There are significant cross-cutting considerations. In coming to a view on transmission charging reforms, we will consider our direction on distribution charging arrangements. We consider that greater alignment between transmission and distribution arrangements would have benefits in being simpler and more consistent. However, there could be factors – such as differing cost drivers or availability of network monitoring – that mean that some options are more feasible. We will therefore consider the extent to which greater consistency is appropriate, including to ensure they provide coherent signals that do not distort one another or wider wholesale signals.

1.69. We will also have regard to the consistency of charging between generation and demand to minimise distortions between large generation, SDG and BTMG. This might include aligning charges, or avoiding having the same charges where conflicting signals would be sent. Any arrangements should ideally use existing data and communications frameworks and have suitable regard to smaller users, particularly those vulnerable users for whom energy supply has significant welfare implications.

1.70. Some options available to us may increase the role or client base of the ESO, which may have price control implications. Other options may require users to sign industry agreements, which may have licence exemption implications. Other options could require third parties to acquire transmission export rights on behalf of the user, which may require regulatory oversight or consumer protection rules. There are options about who this could be. If a supplier or DNO, existing measures may be sufficient. If this role is taken by a new organisation, a Third Party Intermediary or aggregator-type body, monitoring may be required. The interactions of these arrangements with existing contracts may also need to be considered (eg applicability of Connect and Manage arrangements, access to the Balancing Mechanism, and route for export curtailment).

1.71. We recognise the importance of considering the impact on decarbonisation of those options that increase the costs of using the networks for some distributed generation, and particularly renewable generation. We will consider whether any potential carbon impacts of these changes is justified by more efficient location decisions and whether transitional arrangements could be warranted where existing generators are affected. We would only take forward changes where we are confident they would support achieving decarbonisation at least cost.

## Section 5. A summary of our preliminary views

1.72. At this point, we do not have leading options, but would note that options exist to provide a range of improvements, from discrete, low change options to more ambitious, potentially more cost-reflective harmonisation. Our initial principles-based assessment suggests some charges may be more appropriate for certain circumstances than others, depending on our view of the forecasting ability of industry parties and the expected correlation between local and national peak demand. We should also consider the ability of the charges to reflect changes in system conditions. We also do not see any strong in principle reasons why charges for SDG should be less than for large generators where they contribute equivalently to network costs, though we will consider carefully the potential impact on decarbonisation of any changes. All areas of interest have significant stakeholder and practicality implications and a large number of interdependent elements and dependencies that we will be assessing further.

1.73. We intend to follow this working paper with further work on demand and distributed generation charging, followed by quantitative analysis identification, and an initial high-level impact assessment of options to support an initial shortlisting of options to be considered further. We intend to engage with industry throughout this process, and particularly with the DNOs, TOs and ESO on cost drivers and the feasibility of different approaches.