UKERC

UK Energy Research Centre

ofgem consultation:

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

UKERC response

Prof Keith Bell (UKERC Co-Director, University of Strathclyde)

September 2018

Introduction to UKERC

The UK Energy Research Centre (UKERC) carries out world-class, interdisciplinary research into sustainable future energy systems.

It is a focal point of UK energy research and a gateway between the UK and the international energy research communities.

Our whole systems research informs UK policy development and research strategy.

UKERC is funded by The Research Councils UK Energy Programme.

For information please visit: www.ukerc.ac.uk

Follow us on Twitter @UKERCHQ

Acknowledgements:

Thanks are expressed to James Dixon at University of Strathclyde, Simon Gill at the Scottish Government and Scott Mathieson at SP Energy Networks for discussions regarding issues addressed in this response.

Consultation chapter 2: Issues with existing arrangements

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

I believe that Ofgem puts the motivation for change very well in the Executive Summary of the consultation document.

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

I agree with the set of desirable features outlined by Ofgem on pages 11 and 12 of the consultation document.

It is well known that the cost of network capacity to accommodate generation located quite remote from demand is higher than for that connected nearby. It is also generally true that developers of generation capacity have at least some degree of choice in where to build their new plant[1]. Since liberalisation of the electricity supply industry in Britain, it has been a point of principle that the charges levied on generators for using the transmission network should be reflective of the cost of accommodating them. If these charges accurately reflect the costs, they can be used by generation developers to make rational decisions on where and what to build in light of the other variables affecting their investment.

According to Ofgem, over a quarter of Britain's generation capacity is now connected to the distribution network rather than the transmission network and has been exposed to weak or even perverse locational signals in respect of network cost. As shown by Simon Gill of the Scottish Government in an event "Electricity System Change: Flexibility and Costs"[2], the annual per kW use of system charge for generation connected to the network in the same

---

[1] See, for example, Keith Bell, Richard Green, et al, "Project TransmiT: Academic Review of Transmission Charging Arrangements", May 2011, https://www.ofgem.gov.uk/electricity/transmission-networks/forums-seminars-and-working-groups/project-transmit-stakeholder-forum?page=2#block-views-publications-and-updates-block

[2] Electricity System Change: Flexibility and Costs" was held at the University of Strathclyde in January 2018. See http://www.ukerc.ac.uk/network/network-news/electricity-system-change-flexibility-and-costs.html

geographical location in the south of Scotland can vary between - £75 (i.e. the generator is paid for being there) and +£10, depending solely on the voltage at which the generator is connected. This takes no account of the cost of any reinforcements required for connection and enabling operation; it is purely a function of the formulae used to calculate Distribution Use of System (DUoS) and Transmission Network Use of System (TNUoS) charges. DUoS charges levied on generation connected to the distribution network neglects the fact that, in advance of full operation of the Western HVDC Link, *any* additional generation in Scotland - regardless of connection voltage and whether a grid supply point is exporting or not - exacerbates the existing surplus. For most of the year generation exceeds demand in Scotland and the transmission network's ability to export this surplus[3].

Network capacity should not be so high that generation is never curtailed and all demand is always met[4]. Additional network capacity should only be built at the point at which the incremental cost of network capacity equals the incremental cost of lack of capacity, as reflected in the opportunity cost of available energy not reaching the market, plus the cost of replacing it, or the cost of energy users not having their demand satisfied. Generators with transmission network use of system rights are compensated for any lack of access due to network restrictions. However, in general, those connected to the distribution network are not. In addition, whatever benefits they might receive from the way their distribution use of system charge is calculated, a generator triggering an actual reinforcement is liable for a large proportion of the cost of that reinforcement regardless of whether anyone else might benefit from it.

One outcome of the relative weakness of locational signals to generators is that there is less incentive for them to connect in locations where there is spare network capacity. Under current regulatory arrangements, network licensees should increase network capacity by the most cost-effective means which might be via operational measures instead of, or alongside reinforcement of the network. However, consideration by DNOs of operational measures as alternatives to network investment has taken time to become established practice. In addition, the granting of transmission access rights is not helped by some seemingly perverse priority given to generators whose intentions to go ahead with a connection are uncertain. This has contributed to a queue for access of up to 20 GW of generation capacity.

We currently face the possibility that demand for electrical power will begin to grow, potentially significantly, as at least part of the energy demand for heat and transport is electrified. These demands might not be as well diversified as present electrical loads: space heating is required in colder months and on the coldest days, and electric vehicle (EV) charging may happen in the evening when drivers arrive home. The accommodation of peaks

---

[3] In recent years there have been times at which demand in Scotland exceeded the available generation meaning that, for demand in Scotland to be fully satisfied, power had to be imported from England. In future once Hunterston and Torness nuclear power stations have closed, this will become more of issue. The high volume of wind capacity in Scotland and its variability mean that, in the absence of new, schedulable sources of power in Scotland, the transmission system through Scotland and into England must have both the economically correct export capability (striking the optimal balance between network reinforcement costs and the costs of actions to curtail surplus generation in Scotland and replace it with power in England) and a sufficient import capability to provide an acceptable security of supply.

[4] Historically, distribution networks have been designed to be 'fit and forget' with little need for a system operator to pro-actively manage power flows while achieving a certain level of reliability of network access and supply of power. For further discussion, see K. Bell and S. Gill, "Distributed energy resources: technical, regulatory and policy challenges to delivering a highly distributed electricity system", *Energy Policy*, January 2018.

of ‘unrestricted’ EV charging and electric heating is likely to lead to a need for a significant increase in network and generation capacity at a cost that must be recovered from network users.

The cumulative cost of accommodating inflexible demand and distributed generation relative to a fully optimised GB electricity system has been estimated in a much cited piece of modelling conducted at Imperial College to possibly be as high as £10-13 billion by 2050.

Another perspective on cost can be gained by looking at a single substation.

Consider a site with two 10 MVA Transformers that provide a firm (N-1 secure) capacity of 10 MVA. Suppose that peak demand at the substation is currently 10 MVA but is forecast to rise to 13 MVA as a result of more electric heating and adoption of EVs. The Distribution Network Operator (DNO) would consider at least three options[5]:

1. Conventional Reinforcement: replace the two 10 MVA transformers with transformers of the next available standard size. This would incur a £600k one off cost and take two years to deliver. The cost would be recovered from customers over 45 years at an average cost of £40k p.a. (shared between customers in accordance with the charging rules) and would provide an additional 14 MVA of firm capacity available almost every day for the 70 year lifetime of the new transformers.
2. Apply dynamic thermal ratings to the existing transformers. This would incur a one off cost of approximately £100k plus some minor ongoing maintenance costs with an average cost to customers of £7k p.a. This would release between 2 and 2.8 MVA of additional capacity and could be made available within 6 months.
3. Procure a commercial flexible demand service. The market for services needed to reduce demand for long enough in the event of a transformer outage is currently far from being well-developed. Based on typical prices for fast frequency response or short-term operating reserve, the cost of a commercial flexible demand service might be estimated to be ~£40k per annum[6].

The number of years over which the dynamic rating option could be used would depend on the condition of the existing transformers and when they might need to be replaced. The commercial flexible demand service might take the form of a 2-3 year rolling contract. It could be physically provided by genuine demand reduction or demand side management, or by an energy storage device, though whether the price offered would be enough to incentivise the installation of a new device is open to question. Renewals would be subject to market fluctuations and, potentially, competition for the service with the Electricity System Operator (ESO) for wider system reasons[7]. The conventional reinforcement option would make the most capacity available (meaning that further demand growth could be accommodated at no extra cost). However, there is uncertainty associated with the forecast

[5] The scenario and costs are taken from a personal communication to Keith Bell from Scott Mathieson, SP Energy Networks, August 2018, quoted with the permission of the author.

[6] This assumes a need for between 80 and 400 hours of availability to reduce demand by 3 MW. That is, if a transformer were to go out service, it would be possible to reduce demand to within the capacity of the remaining transformer.

[7] The potential for conflict between the ESO and a DNO when trying to make use of the flexibility of resources connected within the distribution networks is one of the main motivations for discussion of what a “DSO” might do.

of demand growth meaning that the investment would be at risk of being stranded. In practice, option 2 or 3 is likely to be used until greater confidence is gained that option 1 is needed (or not needed)[8].

There is, however, another possibility. What if signals to network users were such that demand grew by somewhat less than 3 MVA or perhaps not at all?

Prices charged to demand side low voltage distribution network customers currently have very little relationship with customer's impact on the need for network capacity. Charges to such customers are currently based on annual electrical energy used. The network should be sized for the peak power usage but there is only a weak correlation between annual energy and peak power. For example, Simon Gill has found from data published through the Thames Valley Vision project that customers using around 3500 kWh per year could have a peak demand as low as 2 kW or as high as 4.8 kW[9]. One customer using 7500 kWh per year had a peak demand of nearly 8 kW. The customer using around 3500 kWh per year currently pays around £80 per year for use of the distribution network while someone using 7400 kWh would pay around £165 (these charges are collected by the Supplier and passed on to the DNO). In a putative charging methodology based on peak power, Simon Gill has estimated that the customer using 3500 kWh with a peak of only 2 kW would pay £54 per year while the customer using a similar amount of energy but with a peak of 4.8 kW would pay around £130. The customer with annual consumption of 7500 kWh and a peak of 8 kW would pay around £200. On the other hand, another customer who also used around 7500 kWh but had a peak usage of only 4.5 kW would pay around £125 per year for their use of the network.

In respect of EV charging, flexibility in respect of time and location should be available as vehicles spend a lot of time parked, but not always in the same places. This suggests that the peaks of demand in key locations and on the system as a whole can be reduced relative to the 'unrestricted' peaks. How can energy users be encouraged to make use of that flexibility? One answer is to expose electricity network users to the costs of being inflexible or to give them a share in the benefits of being flexible. A means of doing that is to let network users decide how much network capacity they want to use: choose a cheap, quite low power service (which means, for example, that a certain amount of energy to charge an EV would take longer to get), or a high power, more expensive service. I also agree with Ofgem that "a core level of access could help ensure these basic needs are met and ensure consumers are protected from inappropriate access arrangements for these basic needs" and that a core level of access should be provided. However, thought clearly needs to be given to what 'basic needs' are. This is discussed further in the answer to question 3.

---

[8] Consideration would also need to be given to whether the transformers were the only capacity bottleneck or whether some sections of overhead line or underground cable might also need to be uprated. In addition, the incremental cost of extra network capacity would be small if the condition of the transformers (or any cables of overhead lines that were limiting factors) was such that they would have had to be replaced anyway.

[9] The peak demand quoted here was averaged across the 10 highest half-hours for each customer. See the presentation on network charging that can be found here: http://www.ukerc.ac.uk/network/network-news/electricity-system-change-flexibility-and-costs.html

Consultation chapter 3: proposals for the scope of review of access arrangements

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

I agree that the review should consider options that can:

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

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

As discussed in the answer to question 1, there are strong arguments in favour of reform of charging arrangements. I do not see how charging arrangements can be reformed without simultaneous consideration of quite what it is that network users are being charged for and gain in return. This means that access rights should be clearly defined across all types and at all scales of network user. However, as Ofgem says in the set of desirable features it set out in the introduction to its current consultation, forward-looking charges should be "sufficiently simple, transparent and predictable to enable users to make decisions based on them." It seems to us that this represents a particular challenge in respect of smaller users of the network who have, to date, not needed to give much thought to what an electricity network is, what it provides or how it is paid for.

If the current 'Supplier hub' for electricity retail continues, a Supplier may be expected to buy access on the user's behalf. A responsible Supplier would provide clear information to their customers and make it easy for them to decide the level of access they require with full knowledge of what they would pay. So-called 'smart meters' would allow Suppliers to provide information to their customers and give clear advice on the level of access they are likely to require. In the absence of any active customer choice, the Supplier would be required to buy a reasonable level of access on the customer's behalf at least equal to the 'core threshold' to satisfy 'basic needs'.

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

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

I agree with the proposal that a 'core threshold' should be defined. As argued above, it should be related to peak power usage, and I propose that this is based on average power over short periods of time. Households are generally connected to one secondary substation with many households supplied from one secondary and many secondaries supplied from one primary substation. There will be diversity in the patterns of electricity use among these households although, as noted in the answer to question 1, demand for electricity for heat will be strongly correlated, as may EV charging at particular locations.

A typical domestic heat pump has a rating of 1-2 kW (though with almost continuous operation on the coldest days, possibly supplemented by additional load through resistive top-up heating) and most EV chargers currently have ratings of 3.5 kW or 7 kW. By comparison, electric showers typically have ratings between 8.5 and 10.5 kW. However, people don't (usually) spend all day in the shower and not everyone in a neighbourhood showers at the same time.

The distribution network constraints that are likely to trigger most 'load-related' network investment are thermal constraints[10]. That is, for safe operation, the temperatures of equipment cannot be allowed to exceed equipment-specific thresholds. Temperatures rise when the heating associated with the flow of power, solar radiation, etc. exceeds the cooling afforded by ambient conditions. This translates into a power flow limit on each item of equipment: its "thermal rating", expressed in kVA or MVA. However, when power flow rises in a transformer, underground cable or overhead line due to, for example, increased demand or an outage on a parallel circuit, the temperature takes time to rise. A certain level of power flow must be sustained for some period of time before the equipment's temperature limit will be reached. Thus, although peak power flow is the main factor that determines the capacity that a network should have, it is reasonable to consider the average power over short periods of time, e.g. 5-30 minutes, and to define access rights and a 'core threshold' on such a basis.

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

I agree with the need to improve clarity around the 'firmness' of standard connections to the distribution network and what a user can expect of a non-firm connection. At present, generators on non-firm or 'actively managed' connections carry all the risk associated with the connection even though they have access to little information about the risk. The introduction of financially firm access rights in the distribution networks would expose the granter of the rights – assumed to be the DNO – to at least some of the risk (and reduce the risk for the network user). This would be appropriate given that, by virtue of having better access to relevant information, a DNO should be better able to manage the risk than the network user.

[10] The main other constraints that might trigger 'load-related' investment are breaches of voltage limits or excessive current under short-circuit fault conditions.

I agree with the proposal that distributed generation (DG) should more explicitly agree a 'TEC' level and that routes for them to benefit from Connect and Manage should be more clearly established.

The consultation notes that "many solar generators only want access during daytime hours. We consider that the use of time-profiled access rights could lead to better use of existing network capacity". I agree with this but note that care would be needed in defining the relevant time period, e.g. "off-peak". "Off peak" would concern 'net demand' or the net power flow in or around the location of interest rather simply demand (see our answer to question 8 for further discussion of 'net demand').

I would also note that giving different connectees the opportunity to share their rights could bring similar benefits. For example, a thermal generator might be paired with a wind farm in the same zone and use the same network access rights if the thermal generator runs only when it is not windy[11].

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

Transmission access rights for generators at present are 'evergreen' even though generation plant will have a limited lifetime. Ofgem notes that "[network] reinforcement can only be justified where there is demand for longer term access". Existing, 'evergreen' rights might apparently indicate a long-term need for access though there is currently nothing other than the next annual TNUoS bill to prevent an existing generator suddenly giving up its rights. New connection applications might be taken as an indicator of need but, as has been noted by Ofgem and elsewhere in this response, there is a high volume of generation queuing for connection, only a fraction of which may be expected to go ahead and actually connect. The 4-year ahead capacity market and contracts for difference for renewables might be expected to give some certainty around the generation background, but not every generator is in receipt of such contracts and those that are, might withdraw from them. On the other hand, in network areas facing import constraints, there is currently no long-term market mechanism that would allow a network owner to test the cost-effectiveness of contracting with generation to be available in the importing area as an alternative to reinforcing the network.

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

Both are equally important, not least because of the large and growing volume of distributed generation and the continuing need for transmission.

[11] Short-term trading of rights could achieve the same objective. However, in respect of both sharing and trading, I expect it to be very difficult to define appropriate 'exchange rates' to allow access to be shared or traded across different network zones. Equally, zones should be defined appropriately for the network's structure and key limitations. For further discussion, see, for example, Mohamed Shaaban and Keith Bell, "Assessment of Tradable Short-Term Transmission Access Rights to Integrate Renewable Generation", *Proc. 44th Universities' Power Engineering Conference*, Glasgow, September 2009.

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

I broadly agree with the links outlined in table 1. However:

- I note that peak power flows on any given network boundary do not necessarily coincide with times of peak demand and will be dependent not just on demand and solar PV output (which have strong diurnal trends) but also wind output which has some seasonal trend but only a weak diurnal trend, if any[12]. This means that, on many parts of the network, the time of "off-peak" in the way that matters for network capacity will be different every day.
- I find it difficult to see how 'depth' of access could be delineated in a meaningful way. For example, as previously noted, in advance of full operation of the Western HVDC Link, *any* additional generation in Scotland, regardless of the voltage to which it is connected and its size, exacerbates the existing surplus, for most of the year, of available generation over demand in Scotland and exceeds the transmission network's ability to export the surplus.

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

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

I agree that "that better queue management activities can help speed up the connection of developments that are genuinely ready to progress". If memory serves correctly, transmission connection queue priority changed on the introduction of the British Trading and Transmission Arrangements (BETTA) from priority given to those that wanted to connect earlier to those that had applied earlier, regardless of the requested connection date. I wonder if the old system might have been more effective in facilitating developments that are genuinely ready to progress.

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

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

I agree with what is proposed in paragraph 3.45 but note the potential difficulty of trading access between zones and the need for zones to be well-defined.

---

[12] For further discussion on wind availability trends see D. Hill., D. McMillan., K. Bell and D. Infield, "Application of Auto-regressive Models to UK Wind Speed Data for Power System Impact Studies", *IEEE Trans on Sustainable Energy*, vol. 3, no. 1, January 2012. For an example of how wind generation affects the need for network reinforcement, see W. Bukhsh., K. Bell, A. Vergnol., A. Weynants and J. Sprooten. "Enhanced, risk-based system development process: a case study from the Belgian transmission network", *20th Power System Computation Conference*, Dublin, June 2018.

Consultation chapter 4: proposals for the scope of review of forward-looking network charging

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

I note that some charging methodologies, such as the current version of TNUoS[13] depend on determining how much power would flow on each network branch under given generation and demand conditions. It is often supposed that the absence of decent models of distribution networks at or below 11 kV makes it impossible to implement such methodologies at 11 kV or below. However, the majority of the 11 kV and low voltage (LV) networks in Britain are operated radially, and except where voltages and fault currents need to be determined, do not need detailed models (such as would be used in 'load flow' software) in order to determine whether particular patterns of generation and demand could be accommodated given the thermal limits of the various network branches.

It seems true to us that "without the right signals, the electrification of heat and transport could lead to significant additional costs for consumers" and that "improved forward-looking charges could also reduce distortions from DG receiving credits even where contributing to network constraints, and encourage DG projects that locate in areas where they can provide network benefits and so help reduce consumer bills." However, I do not currently have any quantified evidence available to us on the materiality of these issues.

I agree that "rebalancing towards capacity-based charges could better reflect the costs or benefits created by users' specific access choices" and that, as discussed in our answer to question 1, this will be especially true in a future with more electrified heat and transport. However, I also agree that "this needs to be set against the consumer acceptability of greater locational variability of network charges, and the risk that they could adversely impact those in vulnerable situations". I agree that it would not be appropriate for "use of system charges to mean households' basic, often less flexible needs would differ on a highly granular locational basis".

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

In my view, arrangements for energy trading, system operation and network investment should be based on a common set of principles that apply across all voltage levels and minimise the opportunities for biases or distortions even if detailed implementations differ between them. For an example of the distortions that arise under current arrangements, see the answer to question 1.

Charges to smaller generators that better reflect total costs – and benefits – to the whole system are long over-due. However, they must adequately reflect generators' realistic usage of the network through a year and the extent to which it coincides with other users' impact

---

[13] The current TNUoS methodology uses a linearised load flow and not a 'transport model' as such.

on the network. The review of other aspects of the charging methodologies in respect of the linking of access rights to different conditions, the trading of rights and the sharing of rights has the potential to address this issue.

I agree that the review should also include the basis of TNUoS forward-looking charging of demand and consider options including charging based on an agreed capacity which, in principle, ought to concentrate the minds of Suppliers on how much network access they should buy on behalf of their customers and how to minimise the associated cost while still meeting their customers' needs.

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

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

As previously noted, *any* additional generation connected within an export constrained zone will have an impact on the net export from that zone regardless of the voltage at which it is connected and whether distribution is exporting to transmission or not[14].

In my view, DG should be required to choose the level of access it requires and to have pay – or be paid – for access at a rate that is proportional to the whole electricity system cost of accommodating those rights.

As discussed elsewhere in the consultation, the definition of rights – and, as a consequence, what is paid for them – should take adequate account of how the generator would actually use the network and the costs that would arise as a result. In a world in which the prevalence of low marginal cost, highly variable generation (wind and solar) is increasing, it is no longer sufficient for network planning and system operation to reference demand and generation independently of each other. It is equally unacceptable for key decision makers to have little or no idea of how much DG there is and how it is operating. Flexible and schedulable generation and demand become key in the accommodation of the 'net demand', i.e. the difference between the power available from low marginal cost generation and inflexible demand, both for the system as a whole and in key locations. One motivation for defining 'triads' and basing charges on them is the uncertainty of demand and quite when the peak occurs. However, in my view, 'triads' that treat all DG as negative demand regardless of its characteristics are no longer appropriate.

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

The network is sized according to the power that it transfers, not the total energy across a period of time such as a month or a year. Any use of measures of energy in existing charging methodologies is only because, as in the case of non-half-hourly metered energy users, measurements of power at different times are not available or, as in the case of generators in

---

14 Any generator connected within an import constrained zone would also have an impact and has the potential to reduce the need for network reinforcement to accommodate imports. However, the confidence that a system operator could have in the operation of that generator would also need to be taken into account.

the TNUoS methodology, it is a proxy for the network capacity that would be driven by economic considerations relative to the cost of constraints. Ideally, network charges should be based on capacity, i.e. power. However, the time variation of power export or import, and diversity among network users at each location or in each zone should also be taken into account. As previously noted, arrangements for trading or sharing of access rights have the potential to account for negative correlations in network usage by different parties and allow the total rights applied for and provided to be more efficient than arrangements that treat network usage by different parties entirely independently of each other.

Obliging the demand side to acquire rights ought to incentivise demand side actors (or agents acting on their behalf) to plan in advance the ways in which they can minimise impact on the network. Nonetheless, the natural variability of renewables and of demand that is, to all intents and purposes, inflexible means that rights can be applied for and the network built only on the basis of probabilistic assessment of power flows. This, in turn, means that, at different times over the course of a year or more of operation, the network will appear to have been over-sized or under-sized.

Any connectee to the network should be obliged to acquire rights to export a certain amount of power onto the network and/or import a certain amount from it. Owners of storage or on-site generation with a capacity that can exceed their demand would need to acquire both types of rights: import and export. However, as has been noted before, it is important to take account of the time at which they want to use their rights. (Clearly, an owner of storage will not import and export at the same time). It is up to the rights holder to manage their own activities to stay within the rights limit and make best use of the rights they have acquired. It is up to the administrator of the rights to ensure that the charges levied reflect, as accurately and fairly as possible, the costs of enabling those rights and do not charge network users twice for the same network capacity.

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

The relatively recent implementation of changes to TNUoS through Project TransmiT were, in spite of long deliberations over the details, actually quite modest. Right from the very beginning, the scope of Project TransmiT gave emphasis to pragmatic, easily implementable reform rather than any fundamental review. The recent completion of Project TransmiT should therefore not be used as a reason not to address any of the deeper issues associated with the TNUoS methodology, e.g. the linking of rights with time of use of those rights or the flagging of locations on the network that currently have spare capacity.

Consultation chapter 5: Taking forward this review

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

The network licensees' licence conditions suggest that they have an obligation to address any issues that would better facilitate competition in the generation and supply of electricity and permit "the development, maintenance, and operation of an efficient, co-ordinated, and economical system" for the distribution or transmission of electricity. As a consequence, it might seem obvious that the network licensees should lead the reviews outlined by Ofgem. I also note the following observations made by Ofgem's Chief Engineer in a published letter dated August 13 2018: "It is important that code administrators have the necessary capabilities to efficiently support industry in progressing change proposals. We would expect the ESO to ensure this activity is appropriately resourced." And "We note stakeholder feedback that issues related to GC109 were raised informally with the ESO some time ago. ... We think the ESO should consider whether it could be proactively taking steps to better understand and address these points."

The point about the necessary capabilities is extremely well-made. The reference to being proactive is something that I interpret as criticism of the ESO for being rather less than proactive.

I am concerned that the network licensees might not have the necessary capability or will to lead the reviews of network access and charging that Ofgem is proposing. The DNOs have a poor record in addressing changes to principles, codes or standards (see, for example, the very long time taken to make progress in respect of reforms to DUoS and ER P2 and what I regard as the slow progress of Open Networks[15]). In addition, I am worried by recent reports of yet another major redundancy programme at National Grid.

It seems to me that, although it might be seen as letting the network licensees somewhat off the hook in respect of their licence obligations, there is little alternative to Ofgem leading the proposed reviews. However, it should be noted that Ofgem would not be the sole participants in the review. The industry would be expected to engage and to help bring the benefit of their experience in respect of, for example, the characteristics of their networks and their customers.

I would be in favour of a moderate or comprehensive scope for an SCR. In a narrower scope, there is too great a risk of foot-dragging or inconsistency in the outcomes of industry-led reviews of definition of access rights for large users, processes for their allocation relative to charging arrangements and definition of access rights for smaller users. I do not see how charging arrangements can be reformed without simultaneous consideration of quite what it is that network users are being charged for and gain in return.

[15] In contrast to what Ofgem says in the current consultation document, I am not convinced that Open Networks represents a good example of effective collaboration. If it were really effective, why would companies such as UKPN and WPD feel the need to put considerable time and money into developing and promoting their own future DNO or DSO visions?