ACCESS AND FORWARD-LOOKING CHARGES SCR

SSE Energy Businesses Response

25th August 2021

SSE

For a better world of energy

EXECUTIVE SUMMARY

Introduction to SSE's Energy Businesses

SSE's strategy is to create value for shareholders and society in a sustainable way by developing, building, operating and investing in the electricity infrastructure and businesses needed in the transition to net zero. In delivering this strategy through its highly complementary business model, SSE is fulfilling its core purpose of providing energy needed today while building a better world of energy for tomorrow

SSE's Energy Businesses comprise of the generation assets developed, owned and operated by SSE Renewables and SSE Thermal; Business Energy, SSE's non-domestic energy supply business; and the distributed energy solutions provided by SSE Enterprise. In this response, the terms "SSE's Energy Businesses", "SSE" and "we" are used interchangeably. For the avoidance of doubt, this response does not represent the views of SSE's Networks Businesses (SSEN Transmission and SSEN Distribution).

Summary of response

SSE's Energy Businesses welcome the opportunity to respond to this consultation. Whilst we recognise that the SCR considers a complex range of issues, it is frustrating that despite delays to the process, the minded-to position fails to address many of the biggest issues under consideration in the SCR. As a consequence, this consultation fails to provide the certainty industry needs to confidently make investment decisions, particularly given the proposed implementation date of April 2023.

Ofgem appears to have prioritised addressing solutions for demand customers regarding low carbon technology contribution to net zero. We agree that these are important, but the roll out of these technologies is at an early stage with the absolute growth of capacity still relatively small; there is some time to get these arrangements right. By contrast, we are disappointed that Ofgem appears to have placed relatively lower priority on addressing the same types of problems for large scale generation investment which is critical for meeting 2030 targets and beyond to net zero. Investment in large scale provision of low carbon generation will be the core of delivering GB's net zero ambitions, so it is essential that Ofgem addresses the similar types of barriers to efficient investment in these large-scale technologies with urgency.

Key issues that have not been resolved, or have become increasingly uncertain because of this minded-to decision include:

i. The implications for demand DUoS charges of the removal of costs from customer connection charges.

ii. Ofgem previously strongly indicated a clear direction of travel towards more granular locational DUoS charges and it appears reasonable to expect that suppliers may have been building a technical capability to implement this in quotations and billing from April

2023. However, the minded to decision appears to show a reversal of this direction of travel by reducing the granularity of locational signalling. It is now very unclear to industry how future locational DUoS charges will evolve.

iii. Ofgem previously indicated a strong direction of travel for the value of DUoS charges to become more extreme and potentially flip between being positive and negative but it is no longer clear what the direction of travel will be.

iv. We would welcome the introduction of a measure of spare capacity in calculating DUoS charges to mitigate the risk to tariffs if they should flip between being positive and negative. However, it is not clear if, or how, this may be implemented.

As a supplier, it is very concerning that Ofgem appears to be still planning to introduce large changes to DUoS charges from April 2023, but industry and customers still have no clarity regarding what these changes will be. It now appears that we will not get clarity until early 2022, only one year before the new charging arrangements are supposed to be implemented. It is standard industry practice for business customers to expect to fix their tariffs one to three years in advance as part of their business planning, so this uncertainty is causing higher risk for customers. It is also imposing higher commercial risks on suppliers who are attempting to offer a risk management service to their customers by fixing DUoS tariffs in advance.

As a developer of distribution connected generation, storage and flexibility solutions it is also concerning that the expectation is that industry will continue to make investment decisions while having very little clarity of how either DUoS generator or demand charges will change over asset lifetime.

This section summarises SSE's Energy Businesses' response to the minded-to decision, with further details and discussion provided in the section which follows, providing answers to specific questions.

CONNECTION BOUNDARY

We broadly support the proposal to remove the contribution to reinforcement from smaller demand customers, such as domestic and smaller businesses. However, the case is less clear for removing this for larger demand customers, or for reducing the contribution for generators.

There are strong interactions between connection charges and use of system charges, so it is not possible to reach a definitive view regarding the role of connection charges without also having a clear understanding of how use of system charges will be applied.

We suggest that where connection charges remain, the approaches of changing payment terms and increasing securitization could be helpful changes. This could provide better commercial incentives and better bring DUoS connection charging more in line with existing transmission arrangements.

ACCESS RIGHTS

We support a move in the direction of giving distribution users the option of being physically non-firm because this makes it possible for them to provide flexibility services. However, it is essential that any degree of physical non-firmness is matched with being financially firm in the same way as transmission access rights to avoid distortions in the market for flexibility.

TNUOS CHARGES FOR SMALL DISTRIBUTED GENERATION

It is our view that small, distributed generation (SDG) contributes to network flows in an equivalent way to large generation of the same type. We therefore consider that there should be no difference in treatment based on whether a user is connected to the distribution network, or transmission network.

However, it is our view that Ofgem is addressing this question of equal treatment from the wrong direction. By contrast, it would be better to change the treatment of transmission connected generation, especially low carbon, to bring transmission generation charges into line with distribution connected generators. In this regard, it would be better to wait until after the completion of a wider review of TNUoS charging. This should identify that charging expensive, variable and highly uncertain locational TNUoS to transmission connected low carbon generation, which tends to have a high sunk cost and inability to respond, is not a useful price signal. Instead, it is counter-productive and will unnecessarily increase the cost to customers of delivering net zero.

If Ofgem concludes that it would not be a useful price signal to expose existing distribution connected generators to the additional cost and risk of paying potentially increasingly expensive generation TNUoS charges, then Ofgem should also consider if parity could best be achieved by removing such charges from existing transmission connected generators as well. The same economic arguments apply in each case; when they made their investment decision, neither distribution nor transmission connected generators could have foreseen the substantially increasing cost of northern TNUoS charges which is possible over the next five or more years absent changes to the methodology.

DRAFT IMPACT ASSESSMENT

There are a number of significant deficiencies in the draft impact assessment (IA) which we would urge Ofgem to consider further.

- Installed capacities per technology type are external to the model – this does not appear to address the fact that lower load factors for generation that relocates to the south means that more total capacity would be needed to meet net zero.
- Modelled customer benefit arises from redistributing value from renewables to non-renewables, feeding through to a lower Capacity Mechanism charges - specifically, higher CfD bid prices for northern renewables will effectively subsidise unabated thermal generators in the south.
- The modelling fails to take account of the way the charging and regulatory framework imposes commercial uncertainty on generators, unnecessarily increasing their cost of capital and risk margins. Better outcomes could be delivered through increased

emphasis on delivering net zero at best value to the system and to customers through reducing investor risks, wherever exposure to such risks serves no useful purpose.

- The IA omits externality benefits from geographical diversity of renewables portfolio, including: less total renewables capacity needed; less volatile GB system wind generation profile and consequently less capacity of flexibility services needed; and higher capacity contribution, so less other firm capacity needed.
- Modelling fails to take account of risk of early closure of SDG (and TG, LDG) due to cost of TNUoS charges which risk becoming increasingly more expensive.
- Fails to take account of a likely change in generation mix and the resulting impact on more expensive total system costs. By increasing the TNUoS costs to new distribution connected northern generation, this will tend to reduce the amount of new onshore wind built in the north. However, by reducing the cost and risk for distribution connection charging, this will tend to increase build of PV generation in the south because planning arrangements favour PV over wind in England and Wales. This will tend to result in a change in the GB generation mix from northern wind towards southern PV. The GB system impact of this has not been properly considered in the impact assessment. It is important to consider the seasonal profile disadvantage of PV generation; it will tend to not be available to serve demand for new low carbon technologies of EVs and electric heating when needed most in the winter but will instead tend to contribute to an over-supply of energy in the summer months when it is less likely to be needed.
- The IA does not appear to consider that the accelerated growth of distribution connected PV and onshore wind could come at the expense of displacing investment in lower cost transmission connected PV and onshore wind. This substitution is likely given that both types of generation compete for CfD contracts and may result in a more expensive total system cost.
- The modelling only covers the period to 2040, so does not properly consider the total cost impact of meeting the legally binding net zero objective.

FUTURE ROLE OF NETWORK CHARGES

SSE's Energy Businesses welcome and agree with Ofgem's characterisation of the specific issues with the TNUoS charging methodology identified in the minded-to decision and we would therefore be very supportive of a wider review. However, in embarking on such a review, we would ask that Ofgem seeks to provide near-term reassurance on the direction of travel to give developers the confidence necessary to continue to invest in the interim. Such reassurance might come from a defined set of clear principles to guide the policy development. In SSE's view the principles should address the following key areas:

- **Uncertainty:** this extends beyond simply the level of historic volatility in TNUoS charges and must address the real scope for charges to become significantly more volatile and potentially systematically more expensive in future, imposing an unacceptable level of risk on developers and consequently higher costs of capital.

- **Usefulness:** there are real and significant concerns regarding the current charging methodology, which continues to incentivise the development of unabated thermal generation in the south over renewables in the north; it therefore provides a signal that is completely at odds with GB's energy policy and will undermine efforts to deliver net zero.
  Key to an effective charging regime is the principle that price signals should only be provided where they are useful and cease to be provided where they are either not useful or are counterproductive. For types of user where locational options are restricted (such as onshore and offshore wind), generators can't build anywhere else and so a price signal will tend to serve no useful purpose. By contrast, if particular types of users do enjoy freedom of choice regarding where they could locate (such as storage, hydrogen electrolysis and large industrial demand) then a locational price signal may be more useful. Unfortunately, the current charging methodology appears entirely the wrong way around because it is providing price signals to renewables despite it not being useful to do so, but flooring TNUoS demand charges at £zero, which fails to provide price signals to large sources of demand where it could be useful.
  The OTNR workstream points to an important philosophical shift in the way that both offshore and onshore network will be planned in future which is making bottom-up locational price signals much less useful than they used to be, and redundant for some types of user. Network investment will become an increasingly top-down, co-ordinated build of network and generation with a time horizon of ten years or more. The assumptions underpinning the current bottom-up charging methodology will become increasingly inappropriate because network build will not be driven by bottom-up investment decisions made by individual low carbon generators.
- **Cost:** the current regime imposes disproportionately high costs[1] on northern generators, puts upwards pressure on CfD prices through the inclusion of risk premiums and distorts international competition by levying charges on GB generation that are not faced by generators in interconnected jurisdictions – the inexorable rise in locational TNUoS charges in the north of GB will only make this negative impact on effective cross-border competition worse over time.

SSE considers that it will also be critical to continue to allow quick wins and incremental improvements to be delivered through the code modification process whilst the review is progressing. To this end, it will be important to ensure as narrow a focus as possible on the specific issues to be covered by the review. This will also mitigate the risk that the review stretches out over a number of years, so putting at risk the 2030 targets and potentially derailing the pathway to net zero by 2050.

[1] A recent paper by SSEN Transmission made the case that annual variations of over 50% commonly observed in TNUoS tariffs are disproportionate to the actual cost of network investment and the cumulative allowed revenues of the three TOs, which has totalled within 5% of £2.5 billion over the last five years. See: https://www.ssen-transmission.co.uk/media/5261/ssen-transmission-tnuos-paper-february-2021.pdf.

SSE would welcome serious consideration being given to the removal of wider locational TNUoS charge, at least from renewables. This would provide the dual benefit of reducing cost and uncertainty over the long-term and would better facilitate international competition by reducing the regulatory divergence between increasingly inter-connected jurisdictions. It is also notable that TNUoS does not provide a useful signal for investment in renewables (in the way that it may once have done between competing CCGT projects) and so it should be removed. This would be consistent with the principle that generation charges should either be equal to or average zero.

ANSWERS TO CONSULTATION QUESTIONS

Chapter 3: Connection boundary

Question 3a: Do you agree with our proposals to remove the contribution to reinforcement for demand connections and reduce it for generation? Do you think there are any arguments for going further for generation under the current DUoS arrangements? Please explain why.

<u>Summary</u>

We broadly support the proposal to remove the contribution to reinforcement from smaller demand customers, such as domestic and smaller businesses. However, the case is less clear for removing this for larger demand customers, or for reducing the contribution for generators.

There are strong interactions between connection charges and use of system charges, so it is not possible to reach a definitive view regarding the role of connection charges without also having a clear understanding of how use of system charges will be applied.

We suggest where connection charges remain, the approaches of changing payment terms and increasing securitization could be helpful changes. This could provide better commercial incentives and bring DUoS connection charging more in line with existing transmission arrangements.

<u>Connection chargers versus use of system charges</u>

Unfortunately, it is not possible for us to reach a definite view regarding connection charges without also having clear sight of the knock-on implications and Ofgem's plans for DUoS charges. For this reason, it would have been more helpful had the minded-to decision presented Ofgem's views on all parts of the Access and Forward-Looking Charges (AFLC) SCR at the same time.

A key benefit of relatively deeper connection charges is that network users have a relatively high certainty of a larger proportion of their network cost at the point when they make their investment decision. Therefore, there is a risk that it could be detrimental to investor certainty if there were a redistribution of cost from a relatively certain connection charge to a correspondingly more expensive and considerably more uncertain use of system (UoS) charge instead. This issue would be resolved if UoS charges had characteristics closer to those of connection charges, i.e. by being stable and accurately forecastable over the lifetime of a generation, or demand asset. It is unclear at this stage whether this will be the case.

In our view, a greater reliance on more variable and uncertain UoS charging could cause more expensive total system cost and higher costs to customers of achieving net zero for the following reasons:

- The high sunk cost nature of investment decisions means that users are only able to respond to price signals at the point they make their investment decision (especially true for renewable generation). If users are unable to accurately forecast the future UoS charges for the entire lifetime of their project then they cannot respond to those future charges when they make their investment decision.

- The only response existing users could make to changes in charges would be to close (or remove) the assets they are being charged for in order to avoid an unexpectedly higher UoS charge. However, it would be socially and economically detrimental for customers to be incentivized to decommission, or remove EV charging points, heat pumps, or low carbon generation after they have been installed in order to avoid paying increasingly expensive UoS charges. So for these types of high sunk cost, low carbon assets, a closure incentive is not a useful price signal when considered in the context of wider energy policy goals.
- The application of variable and uncertain UoS charges can increase financial risk, so increasing the cost of capital and risk margins for investors – and therefore increasing the total system cost of installing new low carbon technologies needed to deliver net zero.
- Many distribution connected assets, such as small-scale generation, or batteries will tend to have a relatively shorter project life and be relatively more portable compared with larger transmission connected equivalents. This means that for some technologies, it may be possible for users to avoid paying the full cost of reinforcement that was required to connect them. This is different from larger transmission connected generation and storage which tends to earn project returns over a much longer timescale and which are much less able to be relocated. This difference suggests that there may be some justification for continuing to apply relatively deeper connection charges to shorter project life assets connected to the distribution network, while continuing to charge shallow connection charges to longer project life assets connected to the transmission network.
- There are useful lessons to carry over between transmission and distribution connected users. Where a type of investment is required for strategic net zero purposes and there is limited discretion about location (e.g. domestic demand, small scale business demand, EV charging, electric heating, transmission connected onshore and offshore wind), then locational signals will tend to be counter-productive because they cause increased cost and risk without delivering a useful locational price signal. By contrast, for types of assets where there is substantial discretion regarding location and for which the choice of location may serve the specific purpose of supporting the network (e.g. storage, flexible peaking generation, small scale renewables, large scale business demand), then there may be a stronger case for locational price signals for those types of assets.

There is a risk of causing market distortions if there are differences in UoS charges for distribution and transmission. Distortions would arise, for example, if generation TNUoS is based on capacity to give a locational investment signal, but DUoS charges remain time of use (TOU), so give an operational dispatch signal instead. Providing DG with a TOU network signal is not consistent with delivering a smart flexible system because it distorts operational dispatch by incentivising generation out of economic merit even if there is no network constraint reason to do so. Such out-of-merit operation causes distortions to wholesale electricity prices and will tend to cause unnecessarily high carbon emissions from less efficient small-scale unabated thermal generators. The operational signals from network TOU charges are not smart because they are set in advance, so provide a relatively blunt signal that will incentivise the wrong behaviour most of the time.

Further, TOU signals cannot incentivise efficient delivery of flexibility because they distort competition in flexibility markets. For example, if DG decide their operational dispatch based on earning relatively valuable network credits (or avoiding expensive network charges) then this will effectively sterilize their availability to provide any other form of smarter flexible services in flexibility markets because the price they would have to pay to forgo their network credits (or incur network charges) is likely to be too expensive to make them competitive.

The arguments Ofgem gives for removing connection charges relate more to the current design of connection charges and the way DNOs respond to connection requests. By contrast, it may be worth considering if connection charges could be redesigned in a way to remove the shortcomings in the current approach. Where connection charges remain in place, this could include using a form of long-term marginal cost instead of being based on incremental reinforcement cost and ensuring DNOs do take account of expected future connections when planning network build and calculating charges.

Continuing to provide locational signals to network connected generation but removing them from behind the meter generation will tend to increase market distortions between these two. It may be worth considering charging exports from demand meters in the same way as network connected generators to mitigate this issue.

<u>Domestic and small business charges</u>

We broadly agree with removing the contribution to reinforcement for demand, particularly for domestic and smaller businesses. Regarding demand, it is appropriate to consider whether a particular charge provides a useful price signal and whether it is socially equitable. Regarding domestic demand and small businesses integrated within communities, there is a societal objective to decarbonize heat and transport through electrification and if all domestic demand is to be involved, it would be neither useful nor socially equitable to charge different customers differently for their connection.

It is not useful because the social policy is for all customers to make the transition, so it would be counter-productive for expensive charges to incentivise some customers to not make the transition. Also, a locational charge with the purpose of incentivising customers to change their location by moving house to obtain a cheaper DUoS connection charge would not be a useful, or socially beneficial signal.

Removing the contribution to reinforcement for such demand is more socially equitable because the presence of socialised economic externality benefits means that when an individual customer installs an EV, or electric heating, then the whole of society benefits through reduced greenhouse gas emissions and improved air quality. Since the benefits are socialised across the whole of society, it is appropriate that the costs are also socialised.

It would be helpful if Ofgem could provide industry with clarity as soon as possible regarding whether this approach of removing locational signals to customers from the connection charge will be carried over to similarly removing locational signals from their UoS charge as well.

The same reasons for moving to shallow connection charging would also apply to locational DUoS charges for these same types of customers relating to electric vehicles and electric heating. The partial nature of the minded to decision is confusing for industry because it is not clear if the future decisions regarding DUoS charges will be in line with Ofgem indications so far of moving towards greater granularity and sharper locational signals, or whether it will be more aligned with the rationale of this minded to decisions to reduce DUoS locational price signals

<u>Charges relating to discretionary investments and behind the meter generation</u>

The most appropriate solution may be different for investments where discretionary locational choices can be made by network users, so it may be more appropriate to retain some form of locational price signals.

This may include large I&C customers making locational decisions regarding large new assets that require large electricity supplies. For example, it is appropriate to maintain a locational price signal for large businesses to locate large demand sources, such as data centres, or energy intensive manufacturing in more northern areas where there is a surplus of generation volume.

It may still be appropriate to maintain a consistent approach to DUoS locational pricing for behind the meter generation, and distribution connected generation, as compared with locational pricing for transmission connected generators. In this way, if locational price signals are to be absent from DUoS charges, then they should also be removed from TNUoS charges.

It would also apply to discretionary decisions regarding behind the meter generation and distribution connected generation. This is because there is not the same societal objective for all users to own their own generation assets compared with switching to electrified heat and transport, and there is no societal externality benefit that would arise from for customers owning their own generation instead of larger industrial scale generation.

Ofgem may wish to consider whether it could be appropriate to differentiate in some way between different types of domestic customers, for example a small one bedroom flat compared with a large five bedroom house.

Question 3b: What evidence do you have on the effectiveness of the current connection charging arrangements in being able to send a signal to users and what do you think will

be the effect of our proposed changes? How does this vary between demand and generation connections?

SSE's Energy Businesses' views on the effectiveness and usefulness of existing signals to users and the impact of proposed changes are discussed in the answer to Qn 3a) above.

Question 3c: What are your views on the effectiveness of the current arrangements in facilitating the efficient development and investment in distribution networks? How might this change under our proposals where network companies are required to fund more of this work?

The current arrangements were designed to support incremental development and investment whereas the transition to smarter, flexible networks to support the transition to net zero is likely to require anticipatory investment. The changes proposed would support this transition. The challenge for network companies will be to identify the right areas to invest to minimize the risk of stranded assets should the anticipated needs not materialise. The challenge for Ofgem is to ensure that Uncertainty Mechanisms are effective in supporting this change without introducing undue delays into the process to extend or reinforce the network.

Question 3d: Do you agree whether the need to provide connection customers with certainty of price reduces the potential for capacity to be provided through other means such as flexibility procurement? How might this change under our proposals?

Providing customers with certainty regarding the charges they have to pay should not reduce the potential for providing capacity by other means.

If generation assets could be used to help the network, then this should be incentivised by providing developers of those assets with a revenue stream that reflects the benefit they deliver to the network. It is important that such a revenue stream must be certain and bankable at the point of the developer's investment decision because that is the only time developers can respond to the signal. Our preference for transmission connected storage projects with a long project lifetime would be for a cap and floor mechanism in an equivalent way and for the same economic reasons as this is used for interconnectors. Different solutions may be appropriate for other situations such as projects connected to the distribution network, or with a shorter project life, which may include UoS credits that are certain over the project life, or some form of flexibility contract.

By contrast, short-term flexibility contracts and variable UoS charges fail to enable developers to effectively compete in terms of long-run marginal cost, or appropriately reflect the value to the network of developer investment decisions in flexible assets. This is because short-term flexibility contracts tend to result in clearing prices falling towards short-run marginal cost, while variable

UoS charges tend to have the characteristic where the act of responding to the price signal can make the value of the price signal disappear.

SSE is considering substantial investments in new flexible assets that could deliver substantial value to helping both distribution networks (e.g. SSE's recent acquisition of a 50MW battery storage asset[2]) and transmission networks (e.g. Coire Glas pumped-storage hydro project[3]). Unfortunately, there is currently a market failure in that developers are not able to bankably access the value or benefit they can deliver to the network. This market failure in existing arrangements risks the under provision of flexibility services causing unnecessarily more expensive costs for customers of achieving net zero; costs which otherwise could have been avoided.

Question 3e: What are your views on whether we should retain the High Cost Cap? Is there a case for reviewing its interaction with the voltage rule if customers no longer contribute to reinforcement at the voltage level above the point of connection?

We would support proposals which reduce commercial risk from uncertain tariffs and this principle should be applied to both connection charges and use of system charges for both distribution and transmission charges. If a principle is applied to protect some distribution connected users from the risk of extreme price signals, then equivalent protection should also be provided to transmission connected users based on the same economic rationale.

In situations where the allocation of an extreme charge may be a spurious artefact of a particular charging model, or set of subjective input assumptions, then it is unlikely to be forecastable at the time a user is developing a new generation or demand asset, in which case the extreme price would not provide a useful signal.

We consider there is a case for reviewing the interaction of High Cost Cap with other factors in order to properly assess the potential impacts of its removal.

Question 3f: What are your views on the recovery of the costs associated with transmission that are triggered by a distribution connection? Does this need to be considered alongside wider charging reforms or could a change be made independently?

We note the significant overlap with the specific question on SDG charges – we expand on our views in relation to generation connections in the answer to that question and do not re-state them here.

[2] SSE acquires its first 50MW battery storage asset to provide flexible power: https://www.sse.com/news-and-views/2021/08/sse-acquires-its-first-50mw-battery-storage-asset-to-provide-flexible-power/
[3] Coire Glas project website: https://www.coireglas.com/

We disagree with the premise of this question. The purpose of the AFLC SCR was to consider the aspect of network charging that relates to providing price signals and does not relate to cost recovery. By contrast, it was the purpose of the Targeted Charging Review (TCR) SCR to consider how cost recovery should best be carried out. Ofgem explicitly divided up the two SCRs in this way to draw a clear line between collecting revenue compared with providing price signals.

It is our view that cost recovery should be wholly from final demand in a way that reduces distortions, is fair and in line with Ofgem's TCR decision. Correspondingly, it is appropriate for generator network charges to be either absolutely £zero, or to average £zero.

We welcome a wider review and wider charging reforms but, while this is ongoing, Ofgem should provide reassurance of the long-term direction of travel and continue to allow quick wins to enable industry to continue to invest with confidence. Otherwise, without that certainty, there is a risk of an investment hiatus and unnecessarily expensive costs to customers in the meantime caused by more expensive cost of capital and risk margins.

Question 3g: What are your views on the likelihood of inefficient investment under our proposals (e.g., an increase in project cancellations after some investment has been made)? Are there good arguments for further considering introducing liabilities and securities to mitigate this risk?

There is a risk of SDG renewables closing prematurely at the end of RO support period from end March 2027. If circumstances arose that wholesale power prices were lower, and wind price capture worsened, then those SDG wind generators may become loss making as their annual revenue may fail to cover their annual fixed costs of TNUoS and fixed annual O&M. This could go beyond being unable to repay debt, which could lead to corporate restructuring, but instead to become loss making. This could cause perfectly functioning wind generators to be closed down, dismantled and parts sold on where possible. This premature closure would be economically detrimental because the lost renewable capacity would need to be replaced by new low carbon capacity that could only out-compete existing generators, because those new generators could price the more expensive TNUoS costs into their CfD strike price bids. This would be economically inefficient, cause more expensive total system cost and cause unnecessarily more expensive costs to customers.

This issue arises from the requirement to pay uncertain and potentially increasingly expensive TNUoS charges and applies equally to SDG as it does to LDG and transmission connected renewables. The most appropriate solution would be to treat SDG in the same way as LDG and TG and deliver a solution to TNUoS that applies to *all* low carbon generators, irrespective of the voltage they are connected at.

Question 3h: What are your views on whether the interactions between our connection reforms and the ECCRs must be resolved before we are able to implement our proposed reforms? How do you factor in the effects of the ECCRs (if at all) into decision making, given the levels of uncertainty around subsequent connectee(s)? What suggestions do you have to make our policy and the ECCRs work together most efficiently?

SSE's Energy Businesses do not agree with Ofgem's proposal that eligible persons should "*not expect a reimbursement payment due to the uncertainty as to whether someone would make a subsequent connection*" (para 3.44). This outcome would be unfair, especially where the eligible person had a reasonable expectation that a "second comer" would ultimately share the asset.

If the proposed connection reforms to move to a shallower (or shallow) connection charge are implemented, it would be reasonable to consider amendments to the ECCRs such that subsequent users are not required to make an additional payment (since modified UoS costs would also, presumably, apply). However, further consideration needs to be given to ensure equitable treatment of the eligible person that funded the original reinforcement who would otherwise suffer a detriment as a direct result of the policy decision on charging.

It is important to note that where the eligible person had assessed the risk to be very low that no second comer would ultimately connect within ten years then their investment decision was necessarily risk-based. Where subsequent events and future connections prove their original assessment was valid, it would be discriminatory to now remove any scope for reimbursement of some of the costs incurred. It would not be reasonable to argue that because a particular outcome was uncertain the eligible person should have assumed that outcome had a 0% chance of occurring. An alternative means to provide an equivalent reimbursement payment to the eligible person should be considered.

Chapter 4: Access Rights

Question 4a: Do you agree with our proposal to introduce better defined non-firm access choices at distribution? Do you have comments on their proposed design?

We note the inconsistencies of usage regarding "firmness" between distribution and transmission contexts and suggest it would be helpful if Ofgem were clearer in use of terminology regarding the difference between being physically firm, compared with being *financially* firm.

We support a move in the direction of giving distribution users the option of being physically non-firm because this makes it possible for them to provide flexibility services. However, it is essential that any degree of physical non-firmness is matched with being financially firm in the same way as transmission access rights. This is because financial firmness is necessary to enable smart flexibility markets by enabling price discovery where a user is compensated for giving up their use of their access right at a particular time. Without financially firm access, there is no compensation, so no price discovery, so no effective competition in flexibility markets. If flexibility markets operate with a mixture of participants where some have to be compensated, while others do not, then this will distort the market outcome resulting in worse economic efficiency and higher cost to customers.

If the option of choosing between firm, or non-firm connections without compensation in exchange for cheaper network charges is offered to distribution connected users, then the same choice should be offered regarding transmission access and TNUoS charges for transmission users.

Question 4b: Do you agree with our proposal to introduce new time-profiled access choices at distribution? Do you have any comments on their proposed design?

Formalising choices for time-profiled access where it suits the needs of the user is a positive change, allowing DNOs to better manage utilisation of existing infrastructure. As noted in the answer to Question 3a) above, we consider that UoS charges should, however, be based on capacity rather than TOU to avoid creating market distortions between users connected at distribution and transmission levels.

Question 4c: Can you identify any benefits to shared access rights, which would indicate we have underestimated the likely take-up?

No. In our view, shared access makes no sense, as the most efficient sharing is with the whole market. By contrast, it would be economically inefficient and distortive to deliver sharing solutions that only operate on a local, bilateral basis. Charges already reflect implicit sharing, so it would be double counting to reflect both implicit and explicit sharing.

Question 4d: Do you have any comment on our proposed choice about how to reflect access rights in charges (i.e. connection and/or distribution use of system charges)?

Without having a clear view of Ofgem's intent with regards to UoS charges, it is difficult to assess how a choice of access rights should be reflected in UoS charges. It may be appropriate to reflect access right choices in either connection charges or UoS charges, or both.

If users are to be offered a choice of different access rights such as of being financially firm, versus financially non-firm, then it would be appropriate to reflect these differences in the network charges that they pay. This assumes that if a user requests a financially non-firm connection without compensation, then the DNO does not have to build additional network for them, so does not incur additional network cost on their behalf.

It is important to consider how this could impact competition in flexibility markets. For example, a user could choose financially non-firm access, so have to pay a much cheaper network charge, but in return they would not be compensated for constraints and should expect to be constrained off before users with a financially firm connection. By contrast, users who pay for the additional cost for a financially firm connection should expect to pay a more expensive network charge, but correspondingly be compensated when they are constrained and expect to be constrained relatively less often. This type of situation with a mixture of users being financially firm, and financially non-firm would tend to distort the economic dispatch of users to manage constraints and could lead to a less economically efficient outcome at higher cost to customers.

It is important to ensure that such changes limit opportunities for gaming and include some form of user commitment if a user has caused additional network reinforcement by requesting a financially firm access.

Question 4e: Do you agree with our proposal to not prioritise the introduction of new transmission access choices as part of this Significant Code Review?

If new access choices are offered to distribution connected users, then the same choices should also be offered to transmission connected users.

However, it is our view that it would be better to provide compulsory financially firm access for all users for both distribution and transmission to better facilitate effective competition in flexibility markets.

Question 4f: Do you have views on how access rights should be standardised across DNOs?

Access rights should be standardized across DNOs for the following benefits:

i. Reduce competitive distortions from regulatory arbitrage for generation and demand to locate in one DNO area versus another
ii. Reduce competitive distortions in flexibility markets when DER compete to provide transmission system operation services to the ESO and distribution system operation services to multiple DNOs. This is because, on occasions, congestion, or other system issues in one DNO area may be most efficiently managed using services from DER in a different DNO area and actions may be taken out of economic merit if the access rights are different.
iii. Reduced barrier of administrative cost for generators and demand customers who may have sites in more than one DNO area and would otherwise have to deal with a variety of unnecessary differences between locations. This could relate to differences in connections, responsibilities, charging and commercial implications of bidding in flexibility markets.
iv. Reduce cost for DNOs who would otherwise have to develop their own technical and administrative approaches

Question 4g: Do you have any views on our proposed timescale of 1 April 2023 implementation?

We have some concerns regarding whether 1st April 2023 is still realistic. The AFLC SCR has been delayed and industry still may not receive a final decision from Ofgem until close to the beginning of financial year starting April 2022. It does not appear realistic for industry due process to confirm the detail of proposals, for Ofgem to reach a decision on relevant code changes, and give industry participants sufficient notice to take it into account in their contractual arrangements and commercial decisions.

We support timely implementation, but suggest it is important to ensure that changes are done properly and smoothly rather than being rushed.

Chapter 5: TNUoS charges for SDG

Question 5a: Do you have any evidence that SDG does not contribute to flows in the same way as large generation and, therefore, should not be charged on a consistent basis?

It is our view that SDG does contribute to network flows in an equivalent way to large generation of the same type and we therefore agree that they should be charged on a consistent basis with large generation.

If it is appropriate to treat generators connected to the distribution network and the transmission network in the same way as each other, and it is considered that it would *not* be a useful price signal to expose existing distribution connected generators to the additional cost and risk of paying potentially increasingly expensive generation TNUoS charges, then it should be considered if parity could best be achieved by removing, or capping such charges from existing transmission connected generators as well.

The same economic arguments apply that when they made their investment decision, neither distribution nor transmission connected generators could have foreseen the substantially increasing cost of northern TNUoS charges which is possible over the next five or more years.

Where there are opportunities to provide useful price signals, there should be no difference in treatment due to simply whether a user is connected to the distribution network, or transmission network.

Question 5b: Do you agree with our threshold for applying TNUoS generation charges of 1MW? If not, what would be a better threshold and why?

Ideally, all generation should be treated on an equivalent basis and there should be no threshold for different treatment. Creation of an artificial boundary increases the risk of distortions from regulatory arbitrage of developers choosing to connect to the distribution network compared with the transmission network, or to sizing projects below 1MW compared with above 1MW. This is a particular risk in northern areas where the TNUoS charge is very large.

The 1MW threshold will mean that generators behind a customer meter will be exposed to the inverse of demand TNUoS charges and generators over 1MW will be exposed to generator TNUoS, which leaves network connected generators under 1MW as being the sole group not exposed to TNUoS price signals.

Ofgem should carefully consider how the materiality of this distortion could increase over time, compared with the administrative burden of treating generators <1MW the same as all other generators.

Question 5c: Do you have any evidence that distribution connected generation at a grid supply point has a different impact than directly connected generation?

The Avoided GSP Infrastructure Cost (AGIC) element of the Embedded Export Tariff (EET) is roughly equivalent to the local substation charge paid by transmission connected generators. Ofgem should consider the most appropriate way of dealing with the AGIC charge if distribution connected generators are no longer exposed to the EET

Smaller distribution connected generators, as with large distribution connected generators, should be exposed to the TNUoS Adjustment value that exists to ensure compliance with the Limiting Regulation relating to European regulation EU 838/2010. It is appropriate to treat all generation on an equivalent basis irrespective of their size, or voltage of connection, so it would be appropriate to treat all generation the same as each other in this regard. The economic rational is the same for all types of generation, namely that GB Wider TNUoS charges are much more expensive than other markets, so the Adjustment is required to better facilitate effective competition between generators both within GB and compared with generators in other markets.

Question 5d: Do you have a preference for one of our options for addressing the local charging distortion? If so, please indicate which option and provide your reasons. Are there any options we have missed?

In principle, there should be consistency of treatment regarding local circuit charges for smaller distribution connected generators, large distribution connected generators and transmission connected generators. If a distribution connected generator is using a network asset that is being charged as part of a local circuit tariff, then the distribution connected generator should also pay that local circuit tariff in an equivalent way.

However, there is a clear case for only applying this approach for new distribution connected generators. Given the high sunk cost nature of generation and renewable generation in particular, it would not be a useful price signal to expose existing generators to a new local circuit charge that they could not have anticipated when they made their investment decision. By contrast, a regulatory environment where it is considered appropriate to apply new higher tariffs to generators, even if such charges serve no useful purpose, is very concerning for new generators. Today's new generators are tomorrow's existing generators, meaning that a higher risk regulatory environment would affect new generator investment decisions through causing more expensive cost of capital and more expensive risk margins which would, unfortunately, tend to result in higher costs to customers.

Question 5e: Do you support our position that we should consider transitional arrangements? If so, do you have a preferred option and evidence to support the benefits or risks associated with each option?

We would support grandfathering of existing distribution connected generators from having to begin to pay TNUoS charges. The same economic principles would also indicate it would be a beneficial policy to protect existing transmission connected generators from the risk of exposure to substantially more expensive future TNUoS charges for which they have no ability to forecast, or respond to.

We would also agree with Ofgem that without transitional arrangements there may be a risk of double charging where users have already contributed to the assets which are driving costs.

However, without a clear understanding of the direction of travel on changes to DUoS and with uncertainty on the detailed nature of TNUoS charges (pending the wider review of charging) it is not possible to provide a clear view on benefits and risks of different options, as this will to some extent depend on the scale of the expected impact of the cumulative changes to charging.

Question 5f: Have we identified all the options for administering TNUoS generation charges for SDG? If not, what options have we missed, and why would they be preferable to those we have identified? Can you provide any evidence regarding the implications of the different administrative options for your business?

It would be preferable to assess the administrative options for collection of charges via a more detailed IA process, but the complexity of the DNO led approach is clear and the potential risks of an option that would imposes additional liabilities on suppliers would need to be carefully considered to avoid unintended consequences (e.g. increased risk of supplier failure).

Exposing SDG to TNUoS charges would only make sense if this was done on a capacity basis equivalent to existing TG and LDG, rather than on a Triad TOU basis.

We consider that charging through suppliers using Triad periods by removing the floor at £zero on the EET for generators <1MW would not be practicable or effective. Firstly, because Ofgem is proposing to floor demand charges at £zero, this would only work if the EET were calculated in a different way from TNUoS demand charges. Even if the EET were permitted to be a charge for generators at Triad, this would be detrimental to the operation of the system because generators would simply self-curtail at anticipated Triad times to avoid exposure to the EET charge. In this way, it would not deliver the intended result because generators would still not pay the charges. This would also have the perverse consequence of depriving the system of efficient renewable generation at the times when demand is highest.

Question 5g: Are there any specific issues you think we need to consider, as part of our work on the future role of network charges? Why are these important to consider?

<u>Summary of the problem</u>

The two key problems with the TNUoS locational tariff methodology are that the charges faced by GB generators, particularly those in northern areas, are firstly too expensive and secondly too uncertain over the life of a generation project. These failings lead to the conclusion that it is in the best interest of customers and wider GB society to implement urgent short-term emergency mitigation combined with fundamental long-term reforms to GB network charging to avoid TNUoS increasing the cost to customers of delivering net zero.

SSE therefore welcomes and agrees with the issues identified by Ofgem in the minded-to decision and we would be very supportive of a wider review. However, in embarking on such a review, we would ask that Ofgem seeks to provide near-term reassurance on the direction of travel to give developers the confidence necessary to continue to invest. Such reassurance might come from a defined set of clear principles to guide the policy development. In SSE's view the principles should address the following key areas:

- **Uncertainty:** this extends beyond simply the level of historic volatility in TNUoS charges and must address the real scope for charges to become significantly more volatile in future, imposing an unacceptable level of risk on developers;

- **Usefulness:** there are real and significant concerns regarding the current charging methodology, which continues to incentivise the development of unabated thermal generation in the south over renewables in the north; it therefore provides a signal that is completely at odds with GB's energy policy and will undermine efforts to deliver net zero.

  Key to an effective charging regime is the principle that price signals should only be provided where they are useful and cease to be provided where they are either not useful or are counterproductive. For types of user where locational options are restricted (such as onshore and offshore wind), generators can't build anywhere else and so a price signal will tend to serve no useful purpose. By contrast, if particular types of users do enjoy freedom of choice regarding where they could locate (such as storage, hydrogen electrolysis and large industrial demand) then a locational price signal may be more useful. Unfortunately, the current charging methodology appears entirely the wrong way around because it is providing price signals to renewables despite it not being useful to do so, but flooring TNUoS demand charges at £zero, which fails to provide price signals to large sources of demand where it could be useful.

  The OTNR workstream points to an important philosophical shift in the way that both offshore and onshore network will be planned in future which is making bottom-up locational price signals much less useful than they used to be, and redundant for some types of user. Network investment will become an increasingly top-down, co-ordinated build of network and generation with a time horizon of ten years or more. The assumptions underpinning the current bottom-up charging methodology will become increasingly inappropriate because network build will not be driven by bottom-up investment decisions made by individual low carbon generators.

- **Cost:** as well as the upwards pressure on CfD prices through the inclusion of risk premiums to mitigate developers' exposure to future charging increases, the current regime distorts international competition by levying charges on GB generation that are not faced by generators in interconnected jurisdictions.

SSE considers that it will also be critical to continue to allow quick wins and incremental improvements to be delivered through the code modification process in parallel with the review itself. To this end, it will be important to ensure as narrow a focus as possible on the specific issues to be covered by the review. This will also mitigate the risk that the review stretches out over a number of years, so putting at risk the 2030 targets and potentially derailing the pathway to net zero by 2050.

We agree with the arguments presented in a recent paper by a member company of RenewableUK[4] which noted:

> "[…] *the [European Commission] expects rational regulators to avoid disadvantaging their own generation fleet by aligning network charging with neighbouring countries. By not doing that, regulators risk undermining the competitiveness of domestic power plants compared to imported power that can offer lower prices because it is not exposed to the same regulation.*

This paper then cites analysis undertaken by Cambridge Economic Policy Associates on behalf of the Agency for Cooperation of Energy Regulatory (ACER)[5]:

> *"the application of a capacity-based generation tariff in one country, but not in the other, all things being equal, will encourage investment (especially in peak generators) in the latter country whilst discouraging investment in the former. […] transmission tariffs, levied as a fixed (per MW basis) cost, can also be viewed as a tax on generator prices, which the generators may not be able to fully pass on to final customers."*

It is clear that renewable generators across GB but particularly those in Scotland, are unable to recover unexpected increases in TNUoS via the fixed-price CfD mechanism.

Effective outcomes for a wider review

SSE would welcome serious consideration being given to the removal of wider locational TNUoS charge, at least from renewables. This would provide the dual benefit of reducing cost and uncertainty over the long-term and would better facilitate international competition by reducing the regulatory divergence between increasingly inter-connected jurisdictions. It is also notable that TNUoS does not provide a useful signal for investment in renewables (in the way that it may

[4] Renewable Infrastructure Development Group, *Charging the Wrong Way;* https://cdn.ymaws.com/www.renewableuk.com/resource/resmgr/210524_tnuos_paper_final_for.pdf
[5] Cambridge Economic Policy Associates Ltd, *SCOPING TOWARDS POTENTIAL HARMONISATION OF ELECTRICITY TRANSMISSION TARIFF STRUCTURES*, Aug 2015

once have done between competing CCGT projects) and so it should be removed. This would be consistent with the principle that generation charges should either be equal to or average zero.

Measures that do not go as far but which, in tandem, would deliver significant improvement versus the status quo would be to flatten the TNUoS tariff gradient and provide certainty on future charges at the point of a developer's decision to invest. This would reduce the relative cost of northern TNUoS charges in a long-term bankable way whilst allowing developers to price TNUoS charges into their CfD bid prices, reducing risk premiums and cost of capital.

A shorter-term measure that would not resolve the issues identified but which would provide a clearer focus on the impact on developers would be to improve awareness of cost and risk in the industry. This could be achieved through a requirement for NGESO to publish longer term TNUoS forecasts covering at least 10 years and preferably 25 years.

<u>Specific issues relevant to the future role of network charges</u>

The issues identified by Ofgem in the minded-to position and others of concern to SSE are discussed briefly below.

Delivery of net zero: the same reason that Ofgem provides for moving to weaken locational signals for EVs and heat pumps and distribution connected generation through shallower connection charges in order to deliver "potential benefits in facilitating efforts to achieve net zero" (p9) also applies to weakening locational charges to transmission connected generators as part of the wider TNUoS review. Ofgem recognizes the trade-off with some loss in efficiency being more than offset by faster growth of solar PV and onshore wind at distribution level. The same benefits could also be delivered at the transmission level. This effect is seen most clearly in the recent development regarding the Offshore Transmission Network Review, where the direction of travel appears to be towards taking a top-down longer-term strategic and coordinated approach to planning network and generation instead of the old style, bottom-up piecemeal and incremental approach that the current TNUoS charging methodology is predicated on.

Regulatory risk: SSE is concerned that recent policy decisions are overly focused on delivering benefits to customers based on short-term redistribution of value from renewable generators, and have insufficient focus on providing a healthy market for renewable generation where developers can invest with confidence. Policy decisions that do not adequately consider the long-term costs would be detrimental for the GB energy system and would increase the cost to customers of achieving net zero.

Sending the right signals to demand and storage: even if locational charges were to be removed from EV and heating demand and renewable generators, it would still be a useful price signal to provide demand TNUoS credits for storage in areas where its natural dispatch characteristics would serve to reduce the cost of managing the network. For example, a recent assessment provided by Imperial College London[6] demonstrated that storage in Scotland can

[6] See Pudjiano, Badesa and Strbac, Imperial College London, *Whole-System Value of Long-Duration Energy Storage in a Net-Zero Emission Energy System for Great Britain,* https://imperialcollegelondon.app.box.com/s/24b4ynyq49irqxhqf8n8ygpcso0sl1ft.

mitigate congestion and provide valuable ancillary services to significantly reduce system costs but currently storage is left paying a large net TNUoS charge that does not reflect this benefit and is not calculated based on the actual commercial dispatch profile of a large storage asset. It would be more appropriate for storage to receive a demand credit, which should be based on 100% of a storage asset's full capacity, where it is dispatchable and able to import power at full capacity to help manage constraints. Such a storage demand credit, if introduced, would appropriately result in a net TNUoS credit for storage assets in Scotland which would better reflect the net benefit that such assets can deliver for the transmission system. It may be appropriate to consider larger demand credits for long-duration storage than shorter duration storage that is less able to mitigate constraints and displace the need for network reinforcement. If TNUoS does not provide a locational credit, then it is essential for Ofgem to recognize this missing incentive and consider an alternative means to provide an appropriate replacement incentive.

Implications of the offshore grid: the growth of the offshore grid has large implications for increasing generator risks caused by TNUoS tariff uncertainty across their whole project life. This applies to both existing onshore and offshore generators, as well as those new generators who may be connecting to the new offshore grid. It is important that any wider review considers the impact of the new offshore grid on both of these groups of generators. Existing generators should not be penalized for the recent regulatory and policy decision to substantially extend the size of the offshore grid. It is important that any review removes this risk and, if anything, reduces the cost of wider locational tariffs by attributing credits to generators for notionally avoiding incremental offshore grid investment.

It is notable that with a coordinated strategic network planning approach, the TNUoS locational price signal becomes redundant. For renewables, it is questionable whether locational TNUoS has ever provided a useful signal because locational investment decisions have been dictated by energy resource, planning consent, availability of support scheme and grid connection dates. This redundancy will be even more the case with the new offshore grid coordinating the design of locations for generating stations and network reinforcement ten or more years in advance. If locational decisions have already been made by a top-down strategic planner, then there would be no useful purpose in providing separate bottom-up locational economic price signals to generators because individual generator decisions would not be what is driving the locational design of the transmission system.

For offshore generators, the proposed new coordinated approach to the offshore grid will substantially worsen the commercial risks associated with TNUoS charge uncertainty, compared with today's approach. Where the network design will be co-optimised to deliver best value for the system as a whole it may not necessarily be the best value for a specific generator connecting to it, who will be exposed to the TNUoS Local Tariff. Without mitigation, this is likely to cause a number of detrimental consequences, including:

1. Higher costs to customers because of generators pricing this higher cost of capital and higher TNUoS risk into more expensive CfD bid prices;

2. Delays to net zero from cancelled generation projects after seabed leasing, or CfD auctions once developers find out their TNUoS tariff is likely to be substantially more expensive than they expected and they can no longer afford to build;
3. Stranded network assets become more likely because the tariff for connecting to a particular part of the existing network may be prohibitively expensive for generators because the act of building new network assets may make the TNUoS tariff for using a part of that new network too expensive;
4. Cause premature decommissioning of low carbon generation because once their 15 year CfD contract expires, an existing generator's wholesale market revenue may no longer be sufficient to cover their annual TNUoS and fixed operating costs. This can result in fully operational wind generators prematurely closing down to be replaced by otherwise identical new wind generators who can only afford the TNUoS because they have priced the more expensive TNUoS cost into their new CfD contracts at a higher cost to customers. This premature closure would be economically inefficient and cause a higher cost to customers of achieving net zero.

Tariff volatility: SSE considers that the relevant issue is not just volatility but also the risk of systematically increasing the cost of TNUoS charges over time due to changing market fundamentals, model input assumptions, Ofgem regulatory decisions, government policy and the structure of the charging model. SSE would urge Ofgem to take full account of the impact of increasing the cost of capital and increasing the risk margins that Generators are likely to face in the absence of material changes to the TNUoS charging model.

The scale of investment (estimated at £4.3 billion per year[7]) in new low carbon generation capacity between now and 2050 means that a very substantial reduction in cost to customers over the long term would result from tackling the issues identified with the volatility and level of TNUoS charges to avoid a detrimental impact on cost of capital.

Spare capacity, Backgrounds and other potential changes to the Transport model: in SSE's view, there are a great many defects in the ICRP charging model which lead to tariffs which provide perverse incentives, are too extreme, too volatile, too uncertain and unforecastable over the life of a generation asset. In this regard, we would welcome improvements in the TNUoS tariff model, but are concerned there is a high risk that even if tariff structures were made substantially more complicated, they may still fail to provide a useful economic price signal.

- **Signalling spare capacity** – this would be an improvement, but it would not by itself be enough to provide generators with the lower cost and higher certainty they need to make investment decisions without excessive cost of capital and risk margins. It would go some way to mitigating the risk of highly volatile tariffs in the event of dominant flows switching

[7] PWC estimate a further £1.7 billion per year investment will also be need in new flexible generation. See *Unlocking capital for Net Zero infrastructure*: https://www.pwc.co.uk/assets/document/Unlocking-capital-for-net-zero-PwC-Nov-2020.pdf

direction, which could otherwise result in dramatic swings from large positive charges to large positive credits and back again, which would be impossible to accurately forecast. Even with this improvement, network users would still face the risk of unforecastable TNUoS tariffs because it is not possible to forecast how the balance between demand and generation may evolve over the full lifetime of a generation asset.

- **Backgrounds** – if the ICRP approach were to remain, then the current background approach is reasonable. There may be a benefit in considering an additional background but care needs to be taken to ensure that any increased complexity of tariffs is justified by making any resulting price signal more useful. SSE would not regard backgrounds as the most important issue to be addressed.