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25 August 2021

Dear Patrick,

Electricity North West's response to Ofgem's consultation on its Minded to Positions on the Access and Forward-looking Charges Significant Code Review.

Thank you for the opportunity to respond to this review. As we must base our Final RIIO-ED2 business plan on these proposals, it would assist us if any non-confidential responses could be published as soon as possible after the closing date to enable us to make a further informed assessment of the potential impact.

We have actively supported your work on this Access SCR from the outset and we are concerned at the amount of progress to date. We think that changes to the connection boundary and the access arrangements should be implemented, though we have identified in our detailed response modifications that ought to be made either to aid implementation or to mitigate potential adverse outcomes to customers. We do not support the proposals to levy transmission charges on small distributed generation in the manner suggested and any such change should be delayed until there is a wider review of transmission use of system charges.

We believe you should actively engage now with the ENA to see how these proposals could be implemented and to identify any changes or policy clarifications that need to be included when you publish your final decision to assist the implementation process.

Our detailed responses to your consultation questions are attached.

Yours sincerely

Paul Auckland

Digitally signed by Paul Auckland
Date: 2021.08.25 15:55:23 +01'00'

Paul Auckland
Head of Economic Regulation

ENWL RESPONSES TO CONSULTATION QUESTIONS

3. Connection Boundary Questions

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.

We agree with your proposals to remove the contribution to reinforcement for demand customers, however the justification for reducing it for generation is less clear.

Demand

The current approach has provided effective price signals to new customers and has ensured that the correct balance has been achieved in recovering costs from those customers that are specifically driving those costs and customers more generally. From the data published in Table 1 of the Impact Assessment, on average, under the shallowish connection charging methodology most of the charge relates to the extension assets which remains unchanged under these proposals. The change in respect of the contribution to network reinforcement increases overall connection charges by around 7% for demand, which would appear unlikely to be material in customer decision making. Analysis of the Not Accepted Projects in figure 3 would indicate that, for these projects, the methodology increased the overall connection charges by around 15%. It cannot be ascertained whether the reason why the project did not proceed was high costs of sole use assets (which are not affected by the proposals), the contribution to reinforcement or other factors. Any reduction in connection charges for demand will be primarily borne by demand customers as a whole.

Whilst it is unclear that the current approach will not continue to provide the right price signals in the future, there is justification for a change for demand as outlined in the consultation. As we move to achieving Net Zero, the need to reinforce the networks to support this will become more common, therefore there is justification to remove the reinforcement component from the connection charge as many customers will face such requirements at some point over the coming decades. Many customers will be adopting low carbon technologies not by choice but as a result of legislative change, e.g. the ban on new petrol and diesel vehicles. Current arrangements will disproportionately hit the marginal customer who is unfortunate enough to trigger the requirement. Recovering these costs from DUoS, should in theory allow DNOs to more effectively plan for reinforcement, or use alternatives such as flexibility, to meet the growing need.

The current proposal does not fully address the interaction with the non-firm access proposals. Should non-firm access be a permanent or temporary arrangement whilst reinforcement works are being undertaken? If reinforcement works are extremely expensive but borne by the customers more generally, is the DNO obliged to carry out the work? Under the proposals set out in the Minded-to consultation, the implication is yes but if that is the policy then it should be stated explicitly in the final decision document. An obligation to undertake all reinforcement regardless of costs does not seem fair to customers as a whole. An alternative may be to introduce a form of High-Cost Cap for demand to protect customers generally from excessive reinforcement costs. In many cases the costs in excess of a High-Cost Cap will be borne by developers whereas increased Distribution Use of System (DUoS) charges by end users. Regarding 'non-firm' access, a DNO would only be obliged undertake reinforcement works to reduce curtailment where the costs were below this cap. If the costs were above the cap, the customer would be obliged to fund the excess costs if they wanted the curtailment requirements to be removed.

The proposals may have unintended consequences with customers requesting more capacity than they need, which could be a particular issue in advance of (DUoS) charging reforms that were expected as part of the Access SCR. With these reforms now being delayed or potentially not implemented at all, it may be beneficial to introduce some tactical changes to DUoS from April 2023 to increase capacity charges and reduce unit charges. Customers would not be allowed to reduce their capacity for a period, say five years, following the connection. Such a change should be simple to implement and may help counter some of the possible negative effects and additional costs being passed to demand customers.

<u>Generation</u>

As with demand, the current approach has provided effective price signals to new generation customers. For generation, from the data published in Table 1 of the Impact Assessment, the contribution to network reinforcement increases overall connection charge by around 8% for generation. We do have examples however, where if the shallower boundary were implemented then previous projects which were not economic for the generator would probably go ahead as the excessive costs would be socialised. However, the excessive costs would be borne by demand customers not by generation.

Until DUoS is reformed, smaller generators will still receive credits regardless of whether they are increasing or reducing network costs and any increased costs of funding these credits will also be borne by demand customers. There may be some justification in reducing the contribution to network reinforcement as it could facilitate more strategic approaches to network development and relying less on piecemeal approaches driven by connection applications, but these may be swamped by demand customer funding major reinforcement for the benefit of generation.

Whilst we have reservations about the changes for generation and the impact this could have on charges for demand users, we are concerned about the time it is taking to implement reform. It is assumed that the proposed hybrid approach is designed to provide some mitigation to these potentially adverse effects on charges for demand customers. However, it is not clear whether this will be effective as the bulk of the excess costs are likely to be incurred at higher voltage levels.

There are conflicting points of principle in the minded to decision that we think could be sub optimal and achieve neither intention.

- If Ofgem wants to maintain a locational signal in the connection charge as evidenced by the proposal to retain the High-Cost Cap and retain a same voltage rule for contribution to reinforcement, then it would be better to maintain the current arrangements rather than moving to a shallower connection boundary as proposed.
- If Ofgem wants to reduce connection charges and recover costs more widely from new and existing customers through DUoS charges, then retaining a charge for reinforcement at the same voltage level seems to have limited benefit when the majority of the costs are going to be socialised.

The proposed approach for distributed generation does little to address the potential issues of distortion and/or competition between distribution and transmission charging. This is most acute at 132kV where there is no change and therefore a customer connecting to that voltage level would still pay towards any distribution reinforcement as well as any transmission costs.

The hybrid approach is unlikely to be effective without some form of DUoS reform which include a locational element. Whilst it is accepted that the wider DUoS reforms envisaged as part of the Access SCR are delayed with no clear timescale for implementation, some tactical changes could be introduced from April 2023 to help mitigate some of the harmful effects of the proposals.

An alternative to the shallower approach for generation would be to apply a shallow boundary for generation too with a High-Cost Cap applied to costs up to one voltage level above. This would provide symmetry between generation and demand. The adverse impacts may be mitigated to a large extent by wholesale DUoS reform as expected from the Access SCR, however with this being delayed it is proposed that from April 2023, generator credits are removed in 'generation-dominated' areas or where the level of connected generation exceeds a certain threshold. This change should be relatively simple to implement and reduce the impact on demand customers.

If the hybrid approach is retained, the proposals for storage need to be considered further. The proposed position states that the import and export are to be treated individually for the purpose of connections. It is not clear whether this is valid when there are different connection charge boundaries for demand and generation, and it will be necessary to define which assessment is undertaken first. Also, as storage demand is not final demand and hence does not incur residual charges it is probably better if the whole connection were assessed as generation and not with the import and export considered separately. This needs further consideration in advance of the final decision.

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?

It is not clear what is meant by 'effectiveness' in this question. The shallowish approach gives a good indication of the overall costs of connection for both demand and generation. These costs will need to be considered along with many costs in a decision as to whether a customer will accept the quotation or not. It would be reasonable to assume that connections costs would be more important than other costs for generation compared to demand customers.

As outlined above, the current methodology of including a contribution to network reinforcement has on average, a limited impact on the level of connection charges. This does not mean it doesn't have a very big impact on some connection requests or that they could have more of an impact going forward as the move to Net Zero results in a greater need for network reinforcement. Generation projects in particular tend to be sensitive to cost and location. On reviewing existing applications, in one particular case, demand customers would have to fund a circa £8million investment required to support an approximately 10MW generation connection than is unlikely to progress under the current regime where the charges for reinforcement are something over £6m. It is impossible to forecast exactly what the impact of the proposed changes will be. Hopefully the approach will result in the even more efficient meeting of customer requirements by DNOs. What is essential is a recognition that the impacts of these proposals add to the uncertainty of load forecasts in RIIO-ED2 in general and as a result, the RIIO-ED2 proposals need to be able to respond quickly to changing needs, both in the overall level of funding needed and the ability to adjust prices to customers far quicker than the current 15-month notice period allows.

Another potential issue is a significant rise in the number of applications and in such circumstances, there may be a case for DNOs to have some relief from the obligation to issue all quotations within 65 days of receipt. In order to ease implementation, the decision document needs to be clear on transition issues, e.g. does it apply to all connection applications after 1st April 2023. In flight applications/ projects would continue under the existing methodology unless terminated and a new application submitted.

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?

This is where the proposals ought to have the most benefit. DNOs currently can take a view of what is beneficial for the network as a whole when considering a connection request and the current methodology allows for DNOs to propose an enhanced scheme as opposed to the minimum scheme when producing a quotation in order to achieve this.

With DNOs funding the reinforcement, they should be able to take a more strategic approach to investment rather than waiting for individual connection applications. The success of this approach though relies on investments being justified on the information available at the time and is not subject to hindsight regulation as to whether it turned out to be needed or not. This is particularly true for RIIO-ED2 which is at the start of the journey to Net Zero with greater network investments including in flex services and energy efficiency likely over the coming decades as decarbonisation progresses and hence any proposal to measure the effectiveness of an investment on the utilisation at the end of the RIIO-ED2 period is not appropriate.

Removal of the requirement to fund network reinforcement could encourage customers who currently have higher capacity than they need, to relinquish their unused capacity. However, as stated in the response above, this probably requires minor DUoS reforms to increase charging based on capacity and reducing usage-based charges. A tactical change to this effect should be consider as part of the implementation from April 2023.

The approach to Minimum Cost Scheme should be explicitly stated in the decision document. We consider that to provide protection to existing customers, the existing approach to the Minimum Cost Scheme should be retained. It is not appropriate to focus on minimising the Extension Assets paid for by the connecting customer and maximising the reinforcement element, which is socialised, though High-Cost Caps would mitigate the effects of this.

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?

In responding to this question, we have assumed that this means providing a firm connection utilising a flexible service provider rather than a customer opting for a non-firm flexible connection.

There are not currently stable flexibility markets and sufficient providers to enable flexibility costs to be included in a connection quotation. In addition, the costs of flexibility would need to be converted to an equivalent one-off cost for the lifetime of the asset to be on the same basis as other costs included in the connection charge. For flexibility to be deemed to be efficient this ought to be on the basis that the costs are no greater than the cost of a traditional solution. Therefore, for the purpose of connection charging it would be appropriate to calculate charges based on traditional solutions.

Flexibility would only be required for reinforcement and not network extension. Under the new proposals for demand, as reinforcement costs are not charged to customers, it is solely for DNOs to determine the most appropriate solution. For generation, reinforcement at the point of connection could theoretically be delivered through flexibility though from a practical perspective the connection charge should be levied based on a traditional asset solution. It is doubtful whether in this situation flexibility could be acceptable to the generator, and the generator could request a non-firm connection whilst the reinforcement works are being undertaken.

In summary, it does seem likely that removing the need to determine the need for reinforcement when a request for connection is made, may allow other alternative approaches to be considered by DNOs. This could include flexibility procurement or energy efficiency, should it provide a more beneficial outcome for customers.

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 believe a High-Cost Cap should be retained for generation and a cap introduced for demand and should cover reinforcements up to one voltage level above the point of connection. Such an approach would complement the proposed reforms to non-firm access and provide limits on the costs that need to be incurred by DNOs, and subsequently passed through to customers, to remove curtailment provisions. If Ofgem's policy is that there should be no cost constraints on the removal of curtailment, then there is no need for any High-Cost Cap.

The current High-Cost Cap is calculated on the basis of the cost of the additional generation capacity as it was derived as part of the old DG incentive which allowed for generation driven reinforcement to be recovered from generation. The current mechanism can, in certain circumstances, encourage generators to increase the size of generator to reduce the £/kVA and their contribution to reinforcement costs. Under the current charging methodology, these costs will effectively be picked up by demand customers, and it is these customers who should be protected from excessive reinforcement costs. The cost of per kVA of the reinforcement should be the cost divided by the demand capacity added. Costs in excess of the threshold should be recovered from the generator or demand customer driving the reinforcement.

Consideration needs to be given to how fault level reinforcement should be treated, as it tends not to provide any additional demand capacity.

Question3f: 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?

Continuing to recover transmission costs as part of a distribution connection is clearly illogical considering the other reforms that are being proposed. In effect customers could be charged for costs at two or more voltage levels above the point of connection, whereas the other proposals are looking to limit this to the same voltage for generation and no contribution at all for demand. If the implementation date is April 2023, it is within Ofgem's gift to resolve any perceived issues as part of its final Access SCR Decision and the RIIO-ED2 Final proposals.

The first issue raised in the Minded-To consultation is the application of the New Transmission Capacity incentive included in RIIO-ED1. This clearly must be resolved but Ofgem can remove this in the RIIO-ED2 implementation. This is required in any case in a whole system approach to network development as effectively the New Transmission Capacity (NTC) Incentive can incentivise DNOs to adopt a Distribution solution when a Transmission approach may be in the best interests of all customers.

It is not clear why these transmission costs would need to be included within a DNO's Regulated Asset Value. Contributions from customers are paid to NGESO which then reduces its Exit Charges to the DNO. Exit Charges, except for New Transmission Capacity, are pass-through and are recovered through both the EDCM and CDCM.

The final point is whether such a change should be made in advance of wider DUoS reforms. The key question is when the reforms are likely to be introduced and what is Ofgem's policy intent. If Ofgem believes that these costs should be socialised and recovered from demand customers (i.e. the same as 132kV reinforcement), then no changes are needed.

Transmission works are likely to be triggered by larger EHV customers who receive site specific charges in the EDCM. If Ofgem's policy intent is that these costs continue to be recovered from the customer who triggered the costs then, if it is an EDCM customer, rather than face an upfront connection charge, the customer could receive an annualised site-specific charge instead. This would be quite easy to calculate and easy to implement.

We therefore support the removal of transmission costs from connection charges provided changed are made to allow DNOs to recover these costs through DUoS charges.

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?

As we embark on the road to Net Zero it seems highly unlikely that any investment will turn out to be inefficient or stranded in the medium term. Even if a project is cancelled it is likely that any reinforcement works undertaken will need to be utilised in the future. The main risk is the lack of timely investment resulting in net Zero not be achieved.

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?

It is likely that the ECCR impacts must be resolved before the proposal can be implemented but the ENA Connections COG is looking at approaches that could be used in the interim to allow the changes to proceed from April 2023 if the ECCR2017 cannot be amended or repealed.

It is noted that Regulation 14 requires the Secretary of State is required to review the Regulations and issue report by 6th April 2022 which must,

> *(a) set out the objectives intended to be achieved by these Regulations;*
> *(b) assess the extent to which those objectives are achieved;*
> *(c) assess whether those objectives remain appropriate; and*
> *(d) if those objectives remain appropriate, assess the extent to which they could be achieved in another way which involves less onerous regulatory provision*

Ofgem must actively participate in this review, in particular questioning whether the objectives remain appropriate under the new policy and whether regulations are required at all with the objectives best delivered through the connection charging methodology.

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?

Alternative access products will only useful if they are attractive to customers. Extensive engagement with customers with different characteristics is essential to test this. The use of control equipment at customer premises is also likely to be required if the products are to provide value to DNOs and the acceptability of local control needs to be tested with customers also.

We do not agree that the proposals, as they currently stand, introduce better defined non-firm access choices at distribution.

We agree that, should Ofgem decide to proceed with the proposals, then they should exclude 'small users'. The consultation defines these as households and non-domestic users that do not have an agreement for their maximum capacity usage. To assist in implementation and the development of future code changes, this definition should be amended to 'users whose connection terms are set out in Section 3 of the National Terms of Connection'. Whilst the customers affected will be broadly the same, having greater clarity on the definition and aligning with existing definitions will significantly aid the code modification process.

With the proposed changes to the connection boundary, the perception of these choices is that they are of a temporary nature and are there to facilitate a quicker connection as a 'non-firm' connection will pay the same connection charges and DUoS charges as a 'firm' connection. There is no discussion in the consultation of how long the curtailable access is allowed. Is the DNO obliged to reinforce to remove the constraint, or will the constraint only be removed if the investment cost benefit analysis say it is right to do so? This needs to be more explicit in the decision document. If Ofgem's policy is that the wider customer base should be not funding excessive reinforcement costs to remove a constraint, then High-Cost Caps may be appropriate thresholds where the DNO is not obliged to undertake the reinforcement unless the customer pays the excess costs.

The definition of curtailment needs greater clarification which should be set out in the final decision document. The consultation acknowledges that under current arrangements standard connections already have high levels of firmness and are only curtailed due to maintenance issues, network damage or faults. Curtailment should exclude a Customer Interruption. Where a customer's supply is interrupted under the definition of a Customer Interruption then this should be addressed under the relevant Guaranteed Standards.

In 4.6 of the document, it states that curtailment will be defined in terms of the percentage of time that users are willing to be curtailed and customers will also be able to define the percentage of their total access rights that are non-firm. In Appendix 2 however it states that the degree of curtailment will be measured using the number of hours curtailed. This latter approach is preferable but needs to be clarified in the final decision. The policy also needs to state whether the curtailment limit applies each year or is averaged over several years. There needs to be a clear statement/ methodology on how curtailment limits are set, and whether the methodology should be consistent across all DNOs.

We have concerns with the approach on what happens if the level of curtailment is breached and how breaches are defined (i.e. is it a breach in a single year or over a number of years). The consultation states that the DNO must procure a flexibility service, however there may not be a market in the affected area and the only provider would be the customer who is being curtailed. In this circumstance, the customer can ask for any price if there is an absolute obligation on the DNO to procure it. There must be a ceiling price for this to be workable. The annuitized value of a High-Cost Cap may provide an appropriate ceiling price. It also needs confirmation that any payments under this arrangement are to be treated as Lord Related Expenditure.

As illustrated above, many aspects of this proposal have not been as fully thought through as desirable and set out clearly. These must be addressed in the decision document and not left to the code modification process as otherwise it would be down to industry groups to attempt to agree the approaches which is likely to impact on the delivery timescales.

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?

Time profiled access, coupled with time profiled DUoS charges when the DUOS reforms are announced, could provide a useful tool in managing access and efficient network development. If they are coupled with robust commercial incentives for customers not to exceed their agreed capacity, then this could be a great improvement on current arrangements. If the time-profiled access is not linked to time-profiled DUoS charges, then these arrangements are likely to be temporary and only used to facilitate quicker connections.

In implementing such a proposal, care must be taken to ensure that the approach is not over complicated. It would provide the most benefit if the access periods were aligned with the time periods for DUoS tariffs should these be introduced. It would also aid users if both these time periods aligned with time periods used in balancing services used by NGESO, e.g. EFA Blocks, as users can maximise their output. For example, if the customer had to reduce out on the distribution network for say two hours, if this straddled an EFA block boundary, it could affect their ability to provide Balancing Services for eight hours.

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

We do not think there are any additional benefits. We are also unsure of the take up and in addition to the commercial arrangement more complex control and metering requirements may be required which we would expect are paid for by the customer. We support the approach that this is not taken forward as part of the Access SCR.

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)?

We do not believe that non-firm access can be reflected practically in use of system charges. The changes in connection boundary mean that there will be minimal difference in the connection charge for a firm and non-firm connection for generation and no difference for demand. The main benefit to the customer is likely to have an earlier connection.

Time of Use Access is best valued through DUoS charges, though it may facilitate quicker connections if user requested reduced capacity requirements at peak times. It unlikely that with would have significant financial impact due to the connection charge reforms.

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?

We support the approach to deprioritise transmission access choices at this stage. The Access SCR has progressed far slower than we would have hoped and including transmission access is likely to lead to further delay. It is clear however, that what is needed following the conclusion of the Access SCR is wide-ranging reform of transmission charging and access to potentially mirror what eventually gets implemented in distribution.

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

The best approach is for them to be included in the National Terms of Connection (NTC), Section 3 of Schedule 2B and the Bilateral Connection Agreement set out in Schedule 13 of the Distribution Connection and Use of System Agreement.

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

If the proposals are implemented in the NTC and the decision document is clear and the ambiguities and gaps identified in our response are resolved, then it ought to be possible to implement the changes by April 2023.

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 clear that SDG does not contribute to flows on the transmission system in the same way as large transmission connected generation. If 50MW of generation is connected to the distribution system, it is likely to be largely offset by demand connected to the distribution system. As demand grows on the distribution system, if this is supplied by distribution connected generation then this is unlikely to have any impact on the transmission network. Whereas, if it is supplied by transmission connected generation, then this is likely to require increased investment in distribution networks to meet the demand. This is not discussed at all in the consultation.

This is not to say there isn't an issue, but the focus needs to be on what the impact of distribution generation is at the boundary with the distribution system. It is widely recognised and acknowledged in the consultation that transmission charging is flawed and needs wholesale reform. This proposal perpetuates the flawed thinking from NGESO for many years on this issue and we are concerned that Ofgem may be following the same line.

The approach ought to be for transmission charges to be solely determined at the boundaries to its systems. If a DNO GSP requires some form of Transmission Export Capacity (TEC), then this should be charged to the DNO and recovered from its customers in the same manner that NGESO Exit Charges are recovered. With this type of approach, any justified charges, could be levied on a wider generation base and they would be no need to introduce another arbitrary boundary. Clearly more detailed work is needed to be undertaken to establish the exact circumstances when TEC should be recovered from generators connected to a GSP.

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?

No, it is completely arbitrary and as outlined above, passing any justified charges through DNOs for recovery through DUoS would avoid the need for requiring such a threshold.

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

Yes, as outlined above.

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?

The issue with local circuits highlights the problem with transmission charging generally and the need for reform. We support the proposal in the consultation that this should not be treated as a priority in the Access SCR and is addressed as part of a wider review of transmission charging.

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?

Our preference is for Ofgem to confirm the intention to address any distortion but delay implementation until there is further clarity about the strategic direction. We do not support the implementation of these flawed proposals, even with a delay.

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?

The options identified do appear to be those available for administering TNUOs generation charges. We do not support the comment made in 5.31 that a DNO led model appears unnecessarily complex. DNOs already recover Transmission Exit charges via DUoS and the charging models developed by DNOs as part of the Access SCR work allowed for these to be recovered on a GSP basis, should more locational charging be introduced. Changes to the price control arrangements would be required to enable these costs to be pass-through in the same manner as Transmission Exit charges.

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?

There are clearly issues with current transmission charging arrangements and there is an element of change fatigue. There may be benefit in delaying transmission reforms until the distribution reforms are finalised and an assessment is made on whether similar approaches should be applied to transmission.

7. General question

Question 7: Do you have any other information relevant to the subject matter of this consultation that we should consider in developing our proposals?

We have no further relevant information.

We are currently developing views of potential LRE costs under this minded decision which we will submit as required to reflect the Access SCR minded position in our final ED2 business plan.