Appendix 5: response to Electricity Transmission annex

March 2019

1 Overview

ENWL interfaces almost exclusively with the National Grid as transmission owner in England and Wales but does not interface with the Scottish transmission owners other than as required by our network bordering Scottish Power's area. As such our response focuses on those aspects where there is interaction with the TO in England, as well as any overlap in the regulatory treatment that is additional to the topics responded to in Appendix 1: response to Cross-sector questions.

Our comments below relate to each of the sections of the consultation document, rather than specific questions per se. We trust this response will assist Ofgem as it develops its thinking further.

2 Meet the needs of consumers and network users

In developing proposals in this area, it is important that Ofgem is clear regarding the priorities of consumers and networks users and how these may differ from those of stakeholders. We recognise that there are particular challenges in terms of defining incentives in this area where the transmission owners are removed from consumers in many instances, with other participants such as System Operator, Suppliers and Distribution Network Operators (DNOs) like ENWL more directly connected to consumers. However, it is ultimately consumers who bear the costs associated with the electricity transmission network and it is essential that consumer preferences are prioritised when determining outputs in this category with due regard to the value transmission delivers alongside the impact on consumer bills.

2.1 Stakeholder Satisfaction Output

To this end, we are finely balanced as to whether there is merit in the continuation of the Stakeholder Satisfaction Output and the components that form this. At ENWL, we believe that stakeholder engagement is a fundamental activity that should be undertaken to a good standard by all network companies and sufficient provision should be made for this activity within licensees' base allowances. The current incentive framework in electricity distribution has driven improvements in this area during ED1 but we have not tested with our customers whether this should continue to be subject to additional incentivisation in ED2.

As such, we think there is merit in considering more fundamentally whether or not this activity should be incentivised in electricity transmission. We suggest that the companies' business plans should set out the level of stakeholder engagement that they envisage delivering during the T2 period, with transparency around how this can be measured to demonstrate the effectiveness of this engagement.

Mechanisms like the User Survey and KPIs may be appropriate to maintain as a proxy for customer satisfaction and also as inputs to understanding and improving performance, assuming they can be appropriately calibrated and clearly linked to meaningful benefits for consumers. If these are maintained, it should be noted that TOs interface with a number of other parties and not just connecting customers. As such, the survey and KPIs should reflect the needs and priorities of such customers, including DNOs, and consider enduring interactions as well as new interfaces.

2.2 Timely Connections

Timely Connections should be a minimum requirement for transmission owners and this output may therefore be more appropriately classified as a Licence Obligation under the framework proposed in the Cross Sector methodology. On this basis, it should cover all transmission owners.

2.3 Energy Not Supplied

We believe that the Energy Not Supplied (ENS) incentive scheme should be retained as it reflects the marginal valuation of supply reliability by consumers. As noted by Ofgem, it is neither possible nor likely desirable to drive the number of interruptions to zero. Moving to a penalty-only regime infers either a target of zero, or an asymmetrical incentive with no upside which would disincentivise further improvements beyond target levels. We expect that having no interruptions would not be in consumers' interests because of the costs entailed in that level of resilience, though this would need to be investigated.

We highlight that performance improvements are typically a mix of one-off infrastructure investments and ongoing investment in operational measures. If the latter are not funded either under 'baseline' revenues, or incentive returns, then there is a mismatch between allowed costs and expected performance requirements. We also highlight that DNOs are exposed to an element of the restoration (CML) aspect of Transmission level faults and hence we would be concerned with any changes which may disincentivise improved performance and hence potentially lead to a higher level of incidents experienced on the distribution networks.

Due to the lack of comparators in ET, we believe that past performance should be the prime determinant of future targets. We also believe that targets should be set ex-ante to give certainty to both the ET companies and their stakeholders as to the level of performance being incentivised through the period, and to prevent any inadvertent reversals through the period as noted by Ofgem. We agree that a deadband is inappropriate as it does not reflect customer valuation of service.

We are unconvinced that an improvement factor is appropriate for ET. The overall level of service is such and the number of incidents are so low that an incremental improvement factor trending to eventual zero may not be appropriate in face of the significant annual volatility evidenced in Appendix 1.

In using historic performance as the key factor in setting future targets the marginal incentive rate should be aligned with an updated value for VoLL. If an ET licensee includes proposals for ex-ante funding for improvements in its submission, then an appropriate adjustment to its future targets should be made to reflect the expected funded improvements. This would allow licensees to commit to proactive investments, rather than simply reacting to an incentive regime.

We agree that the ENS rate should be based on an updated VoLL value and highlight that it is important that licensees are directly exposed to the assumed impacts of a loss of supply such that their decision making reflects actual economic and social effects.

We note Ofgem's acknowledgement of our current work in this area. We also agree that it is likely to be appropriate to set a single value of VoLL for ET as the scale and interconnectedness of the infrastructure involved means that it serves an aggregated set of customers. We acknowledge that customers directly connected to the Transmission network may have a lower VoLL than domestic customers and hence the ET VoLL value may be lower than the ED equivalent. Our current VoLL work suggests that there is significant disaggregation of VoLL at the SME and domestic customer level such that it is likely that different VoLL both within and between DNOs may be appropriate. We therefore believe that it is essential that the appropriate value for VoLL for electricity distribution be considered as separate from the current decision making process for transmission and that T2 is not deemed to be precedent setting in this area.

We agree that retaining a financial collar for the ENS incentive would seem to be an appropriate way of sharing the risk between licensee and customers. We agree that, given the high levels of absolute reliability, 0MWh represents an absolute upside cap in any case.

We believe that more work needs to be done to look at the feasibility of moving to use of CI/CML measures for incentivising reliability, and that this may be more appropriate for ET3 given the likely scale of data challenges involved. We highlight that moving to an IIS-type measurement will require careful calibration of the CI and CML marginal rates to ensure that major users are not disadvantaged for example.

We agree that specified exceptional events should be excluded, but that the exceptions criteria should be updated. Where appropriate, we suggest that the exceptional event definitions should be aligned with those for DNOs to ensure a consistent approach and valuation, particularly relating to the 132kV network which is part of distribution in England and Wales but is under the TO licensees in Scotland. Discussion on exceptional events needs to be related to any proactive resilience investments proposed by the TOs as it may be that proactive investment is balanced by changes in thresholds.

3 Deliver an environmentally sustainable network

3.1 Environmental framework - Business Plans and annual monitoring

In developing their Business Plans, we believe TOs should give consideration to the environmental impacts of their activities. We expect that the plans submitted would as a minimum ensure compliance with all relevant legal and regulatory standards in this area. Where licensees wish to go beyond these minimum standards, the costs associated with this enhanced delivery should be scrutinised qualitatively in narrative and quantitatively in the form of consumer willingness to pay.

We suggest that the Cost Benefit Analysis (CBAs) used to inform decision making should capture the wider environmental impacts of projects and benefits that are realised by other parties, including end consumers, should be factored in. However, given the scale and cost of transmission infrastructure, it may be more appropriate to maintain existing assets but seek alternative means of delivering solutions to customers' needs, including via non-technical solutions and delivery at distribution voltages. It is therefore essential that sufficient flexibility is in place within the TOs' plans to allow alternative approaches to be considered and, where appropriate, utilised as this may often have a lower environmental impact than traditional TO asset-based approaches.

We do believe there is merit in increased transparency regarding the impact of transmission networks on the environment and annual reporting in this area could assist consumers and stakeholders understand and evaluate the actions being undertaken by TOs. However, we are mindful of the number of reports that are currently required under the transmission licence and suggest that a single public-facing reporting requirement that clearly sets out the licensee's performance against its Business Plan would be preferable to the current myriad of documents. In the event that Ofgem pursues this approach, an evolution of the Business Plan Commitment reporting currently utilised in electricity distribution may be beneficial. We would be happy to discuss our thoughts on how this approach could be evolved if beneficial.

3.2 Potential for bespoke ODIs around the low carbon transition

We believe that it is important that network companies play a proactive role in the low carbon transition, responding to the needs of their customers and stakeholders. However, we are unclear what additional ODIs may be required, either for electricity transmission as a sector or on a bespoke basis for one or more transmission licensee that will deliver additional value for consumers. In order to be able to form a more meaningful view, further information on the nature of a potential ODI is required. In setting any bespoke ODI's around the low carbon transition these will need to be flexible for the timing and nature of any interventions consumers require and a careful balance will need to be struck so that ODIs do not actually incentivise what turns out to be the wrong thing as the low carbon transition unfolds and DNOs bring forward their business plans.

3.3 SF_6 and other insulation and interruption gases (IIG) leakage

ENWL has no response to make in relation to SF_6 and other IIG leakage.

3.4 Electricity losses from the transmission network

As part of taking a whole system view, we believe consideration should be given to carbon impact of decisions. With increasing levels of low carbon generation, reducing losses has the potential to reduce the marginal plant requirements which is increasingly more carbon intensive than alternatives. To this end, we believe that network companies, including TOs, should be required to consider an end-to-end carbon reduction strategy as part of investment decision making and the potential impact of losses should be part of this.

At this stage, we do not have a view on whether improving the metering and energy efficiency of substations is in consumers' interests. However, a CBA approach that considers carbon impacts on a whole system basis would inform a view on whether or not such investment is in consumers' interests.

Increased transparency regarding how TOs are making these decisions would be beneficial and also allow other parties to learn from the actions undertaken by TOs. We agree that there may not be merit in requiring the TOs to issue an annual losses report. However, we suggest that a single overarching performance report, as discussed above in section 3.1, could include significant developments in this area.

3.5 Visual amenity impacts of transmission infrastructure

We agree that this seems appropriate as stakeholders need to be fully engaged in the consultation process and greater transparency of the decision-making process should be welcome.

We agree that mitigation measures in highly sensitive areas can have a significant impact on the visual landscape and improve amenity. For those areas where the visual landscape is a key part of their economic offering, this can also have a positive economic impact.

We also agree that sizing the ET2 provisions must take account of contemporary customer willingness-to-pay for improvements. We highlight however that this willingness-to-pay should not be restricted to Transmission infrastructure only, but should account for all electricity overhead line equipment, including that of the DNOs. Potentially, due to the extremely high cost of mitigating Transmission overhead lines, far more cost-effective visual amenity improvements can be achieved by mitigating DNO equipment, which can also include steel tower routes. Also because of the bespoke nature of transmission projects for visual amenity, the site specific willingness to pay compared with the specific project cost should be investigated, especially where solutions involve high cost engineering such as cable tunnels in one area where lower cost mitigation measures might suffice elsewhere which have a better willingness to pay to cost ratio.

We note that the existing ET mitigation programme results in highly targeted and relatively restricted undergrounding, which leaves large areas of the country untouched (the North West for example). We suggest that an equivalent level of funding for the DNO undergrounding scheme would not only generate greater overall amenity benefit, but a far more diversified one, ensuring that all areas of the country benefit. Taking a whole system approach to this output area could deliver significant benefits for consumers if appropriately managed.

We agree that the scope of the mitigation programme is more foreseeable within a five-year price control period and likely to be identified further in advance due to the planning timescales for Transmission infrastructure projects. However, we are unaware whether the ETs currently have projects identified to a level of detail that would enable the identification of a specific Price Control Deliverable (PCD) in this area. Given the bespoke nature of each visual mitigation scheme, the price control deliverable should be set in tandem with setting the efficient cost allowances.

We suggest that the balance between high and low-cost mitigation projects is not set in advance, unless evidenced by customer willingness-to-pay. Any cap on low-cost solutions would be arbitrary and would not recognise that the identification, planning and delivery timescale for these works is generally far shorter than that for engineering solutions. The low-cost mitigation works also allow a far wider implementation of improvements than engineering solutions alone which, as noted, leave large areas of the country without any benefit.

We agree that the scope of the programme should remain restricted to Designated Areas. These are usually designated on account of their visual appearance in the first place; hence the impact of above-ground infrastructure is usually greater in these areas. However, we suggest that consideration could be given to the equivalent of the 10% rule used in electricity distribution which enables the utilisation of a portion of the undergrounding entitlement outside of Designated Areas, as long as it is appropriately supported by the relevant stakeholders.

3.6 Environmental Discretionary Reward (EDR)

We support the removal of this incentive in its current form as we are unconvinced that it presents good value for money for consumers. We are unconvinced that discretionary rewards are as effective as other mechanisms in driving enhanced performance as licensees are unable to build business cases for discretionary investment to deliver change to benefit customers when the potential upside is unpredictable.

We suggest there may be merit in Ofgem reviewing the design of this mechanism to ensure that any lessons that can be learnt from the design and implementation of the EDR for other incentives.

If there is customer and stakeholder support including a willingness to pay for environmental enhancements then an appropriate incentive should be built around enabling and delivering these environmental outputs.

4 Maintain a safe and resilient network

4.1 Safety

We support the view that the Health and Safety Executive (HSE) is the most appropriate body to regulate safety performance and therefore support the proposed approach set out in paragraph 5.6.

4.2 Network Access Policy (NAP)

We believe there is merit in maintaining the Network Access Policy (NAP) as a means for the TOs to effectively communicate with the ESO and make the necessary trade-offs to ensure timely access to the transmission system for necessary work.

Following the separation of the ESO role from National Grid's TO function, we do see merit in the NAP covering all three of the TOs going forward. This will increase transparency regarding the interface between the ESO and NGET as TO which we believe is beneficial in terms of mitigating any potential or actual conflicts of interests within National Grid.

At the electricity distribution level, there is a different working relationship with the ESO. Whilst there is merit in increasing communication and co-ordination between the ESO and DSO/DNOs, we are not convinced that this is driven from the same challenges that are behind the NAP. As such, we do not consider it will be beneficial to extend the NAP at this time and suggest alternative communication channels may be more appropriate going forward. We suggest that the outputs from the Open Networks work streams should inform this going forward; with further consideration given as the ED2 control develops.

4.3 Successful delivery of large capital investment projects

We support the development of clear PCDs around the successful delivery of large capital investment projects. The use of a milestone-based approach seems to be appropriate but we would expect this to be considered on a case-by-case basis.

We agree that companies should not benefit from delays to large projects that are needed by consumers, especially where there is clear and demonstrable detriment to them. If a consumer need changes and its economic and efficient to stop or delay work on a large project then this should equally be considered by the TO. However, the RIIO-2 framework is we understand seeking to be a lower fair returns framework with lower risk for companies. As such Ofgem needs to be mindful that its proposals do not inadvertently increase the risk borne by TOs as this could potentially increase costs to consumers or make large projects less investable.

5 Cost assessment

We recognise that it is more challenging to undertake cost assessment for transmission where the sector is dominated by one company, National Grid TO, as opposed to distribution where comparative regulation works well. We therefore believe it is important that other relevant benchmarks are considered. We also suggest that it is important that a bottom-up in detail assessment of costs is required as well as top down so Ofgem can be confident the costs are justified and efficient. Given the lack of comparators, we suggest that the role for expert review is particularly important for transmission to support Ofgem's understanding of the proposed costs.

We understand the proposed changes to the cost categories and at a high level these seem reasonable. However, we are unclear how some costs, such as operational IT, will map to these.

At a high level, the principles proposed to assess appropriate cost drivers seem reasonable. However, as with many principles-based approaches, it is how these principles are used that will determine their appropriateness. To that end, we suggest further clarity on how Ofgem expects to develop and use these cost drivers would be beneficial for the licensees as they develop their Business Plans and for the User Groups and other stakeholders to be able to consider and, where appropriate, challenge the TOs' plans. We agree with the observation that the relationship between cost drivers and network costs may change for RIIO-2 and that this needs to be borne in mind.

We note Ofgem's observation in paragraph 6.29 regarding TOTEX sharing factors and suggest that it is important that an in-depth assessment of how Ofgem's proposed approach to TOTEX sharing factors is considered to ensure this does not result in distorted incentives for companies.

We note the proposed timeline at the end of this section for the development of the Business Plan templates and observe, based on our experience, that it can be very time-consuming and challenging for Ofgem and licensees if there is significant changes between different iterations of the BPDT templates. This will be particularly so for RIIO-2 where licensees are taking iterations of their plans to the Customer Engagement Groups / User Groups prior to submission to Ofgem. We suggest that it may be beneficial to update the timeline to show these submissions to the Customer Engagement Groups / User Groups as the timing of these will impact on licensees' ability to respond to updated templates.

6 Uncertainty mechanisms

As set out in our response to the Cross Sector consultation document (Appendix 1), we believe flexibility in the price control arrangements will be essential for RIIO-2 to enable the decarbonisation of the energy system through ensuring the right whole system solutions are taken forward. With an uncertain outlook as to the needs of customers from the transmission system, and potentially a continued diminishing role of transmission relative to distribution as decentralisation of energy resources continues, then the price control settlement for electricity transmission will need to adapt and be responsive to this increased uncertainty.

We note that Ofgem has talked at stakeholder events about the potential risk for consumers of locking into transmission solutions as part of RIIO-ET2 when better solutions might be brought forward later by amongst others service providers and ED companies which we believe is a valid concern. We therefore believe that an increased use of uncertainty mechanisms is likely to be required for ET2 with a smaller proportion of costs set as a baseline ex-ante allowance to minimise this risk identified by Ofgem.

In general for National Grid TO in England and Wales the uncertainty mechanisms seem to have worked well in protecting customers. These should be recalibrated and any new mechanisms developed and shared in enough detail so that stakeholders can provide input to them. In developing these, we suggest Ofgem needs to consider how it can satisfy itself that proposals included in transmission are the most cost effective response to a given issue, especially where there may be alternatives that could be brought forward as part of ED2 plans.

We have actively engaged with National Grid TO in respect of the plan they are developing and what this means for the North West. National Grid TO has been active in reaching out to us and has listened to our feedback, including from what we have seen to date taking some of it on board.