

UK Power Networks' Response to Ofgem RIIO-ED2 Draft Determinations



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QUESTIONS IN THE DRAFT DETERMINATIONS - OVERVIEW DOCUMENT

Adjusting allowances for uncertainty

Q1. Do you agree with our proposal to introduce a new funding mechanism for PoLR activities?

We believe amendments are needed to the terms of Standard Licence Condition 31F (SLC 31F), which allows Distribution Networks Operators (DNOs) to act as providers of last resort (PoLR) to own, develop, manage, or operate an Electric Vehicle (EV) charge point, when the market fails. We believe that these amendments are crucial to protecting customers from shouldering an unnecessary cost burden – especially in the current context of current energy prices.

We want to emphasise that, while DNOs have a vital part to play within the EV charging ecosystem to facilitate adequate charging infrastructure, they should not own and operate charge points. We detail our views below:

- The UK Government's Electric Vehicle (EV) Infrastructure Strategy published on 29 March 2022 places the responsibility for adequate supply of EV charging facilities on local authorities, not DNOs (or Ofgem). A statutory duty to this effect will be introduced when legislative time allows;
- DNOs are likely to incur higher than necessary costs for this activity since it is not their primary business expertise, and they do not benefit from the economies of scale charge point operators have;
- Funding charge points through DNOs is regressive - given that PoLR activities are intended for local, specific market failures, local taxpayers should fund charge points, not electricity consumers; and
- If the charging assets were to be added to a DNO's Regulatory Asset Value (RAV), DNOs would have incentives to proactively identify sites that meet the criteria of SLC 31F to increase their capital base.

We recognise the existence of market failures, but we think that the primary solution should be to work with local authorities to identify market failures and appropriate solutions. As part of our "Charge Collective" Network Innovation Allowance (NIA) project, we were able to articulate the causes of these market failures and present our suggested solution: **working with local authorities to identify where such market failures persist, and enabling lower cost connections in these areas to overcome the upfront capital hurdle that is preventing investment¹.**

This approach has three key advantages:

- It allows local authorities to remain in control of the infrastructure provided for their residents and on their streets;
- It allows charge point operators to develop their charging networks in areas that provide wider societal benefits; and
- It minimises cost by providing only the subsidy necessary to connect the charge points to the distribution network. The market will then take over; once the charge points are in place, this will stimulate demand for EVs in the area, and therefore usage of and demand for the charge points.

Therefore, we think that if SLC 31F is maintained and funded going forwards, Ofgem must make amendments to ensure that:

- The criteria that determine the application of SLC 31F are strict and assessed on a case-by-case basis;
- Only local authorities can instigate the use of SLC 31F;
- DNOs are not allowed to own charging assets. Local authorities should fund and own the assets, while DNOs would only supply the connection to the network;

¹ Please see the first report from the project for more details: [WP1 HANDBOOK \(ukpowernetworks.co.uk\)](https://ukpowernetworks.co.uk/wp1-handbook)

- Charge point operators should be accountable for providing adequate customer support (such as 24/7 call centre support) and other services identified in BEIS's report on the consumer experience at public charge points²; and
- The use of charging assets and their management costs are monitored. This data should be used to enable Ofgem to evaluate the value for money and the distributional impacts of SLC 31F.

Q2. What are your views on our two proposed options, and do you agree with our preferred option of a DRS?

Notwithstanding our concerns about SLC 31F which we presented in our response to Q1 above, we think that Directly Remunerated Services (DRS) is an **appropriate option**.

Q3. Do you agree with our proposal to introduce a re-opener to deal with recommendations from the Storm Arwen review, our proposed trigger and re-opener window?

We support the introduction of a re-opener to adjust our ex-ante allowance considering that Ofgem and the Energy Emergencies Executive Committee (E3C) have mandated the review of several industry standards and guidance. We would expect changes to standards and guidance to potentially impact our scope of work and our costs, and therefore a re-opener is appropriate.

We support the principle of a single window in January 2024 to trigger the re-opener, on the basis that the deadlines for Ofgem and E3C's reviews are set for 31 December 2022 at the latest. We want to stress that it is essential that the window is set far enough after the rules and requirements have changed to allow us to identify any variations to scope and corresponding costs and to make the necessary submissions to operate the re-opener. If there were to be a delay to Ofgem's or E3C's work, we would expect the window to be pushed back appropriately, or effectively tied to a number of months after the completion of Ofgem and E3C's work.

We disagree with the application of the materiality threshold. We consider that changes to legal requirements, which are outside of our control, should be fully funded. It would be inappropriate to be given extra obligations without commensurate funding.

Q4. Do you agree with our proposal to maintain the RIIO-ED1 High Value Project mechanism and focus it on non-load related HVPs in RIIO-ED2?

We agree with the proposal to maintain the RIIO-ED1 High Value Project re-opener mechanism alongside the defined scope, trigger, re-opener window and materiality threshold. We note that this mechanism is intended for individual non-load schemes of £25 million or more that are not included in ex-ante allowances. Ofgem will therefore need to provide clarity as part of its Final Determinations as to which individual non-load schemes have been included in ex-ante funding to enable any new schemes to be readily identifiable under this proposed re-opener mechanism. Ofgem should also make clear whether the re-opener threshold is inclusive of associated indirects. Given our Business Plan contained information on an Indirect Scaler mechanism, we believe this should be the case.

Q5. Do you agree with our proposal to remove the RIIO-ED1 smart meter volume driver?

We disagree with removing the volume driver in RIIO-ED2 given that the volume of work depends on actions by third parties and is not within our control.

The smart meter volume driver was designed to address three uncertainties:

- **RIIO-ED1 delays.** Any supplier-led delivery delays from RIIO-ED1 would, even on the unlikely assumption that the total volume of work does not change, result in RIIO-ED2 volumes being higher than submitted.

² BEIS, 25 March 2022, The consumer experience at public charge points

Delivery delays are not treated in a fair and symmetrical way between RIIO-ED1 and RIIO-ED2 - a reduction in volumes from RIIO-ED1 results in money flowing back to customers through the RIIO-ED1 volume driver, however higher RIIO-ED2 volumes are to be funded solely by the DNO. This is not at all reasonable. Since the RIIO-ED2 plan was drafted, we have seen RIIO-ED1 smart meter deployments drop by 0.5 million from our Business Plan Data Tables (BPDT) forecast of 4.9 million for reasons outside of our control. This evidences how quickly the smart meter roll out volumes can change and supports the need for a volume driver mechanism that protects consumers and DNOs alike;

- **Volume of smart meters.** The total volume of smart meters to be installed is itself uncertain. Suppliers are required to achieve a minimum 85% roll-out target, but it is possible that some suppliers will exceed this target. Furthermore, we are starting to forecast the need for network interventions to support the replacement of the earlier smart meters (SMETS1) deployed to customers through age and obsolescence. Whilst we would expect the intervention rate to be lower than for the initial roll out, network issues occur when meters are changed so some intervention-related work is expected. This relative unknown further supports the need for a volume-driven mechanism, with a broad enough scope to capture these subsequent interventions; and
- **Intervention rate.** There is variability in the actual intervention rate itself, with industry intervention rates fluctuating between 2.24% and 7.63% across RIIO-ED1. This variability counters any logic for utilising an industry median intervention rate which will over and under remunerate different DNOs without justification. This would appear to run counter to Ofgem's stated desire to see outperformance from genuine efficiency rather than "windfall" gains. We request that Ofgem maintains the existing incentives.

The RIIO-ED1 volume driver protects customers and ensures any outperformance is driven from genuine unit cost efficiency; we strongly believe this continues to be the appropriate mechanism for RIIO-ED2. The volume driver offers protection to both customers and DNOs, and we cannot see any merit or evidence in removing this protection. We also believe the continuation of the smart meter volume driver would facilitate further smart developments and deployments, with customers protected from variations in outturn requirements. An ex-ante mechanism fails to achieve this and would place a burden on Ofgem to amend the smart meter funding arrangements in-period.

Q6. Do you agree with our proposed approach for a common materiality threshold being applied to RIIO-ED2?

We disagree with the application of a common materiality threshold set at 1% of base revenue (after application of the Totex Incentive Mechanism (TIM)) coupled with the fact that Ofgem precludes the aggregation of projects to meet the threshold.

1% of base revenue (after TIM) would imply a threshold at circa £26 million for UK Power Networks for individual projects and disproportionately impacts the larger DNOs. This threshold is higher than almost every single project we have undertaken during RIIO-ED1 and what we reasonably expect to undertake in RIIO-ED2. This level of threshold would leave disproportionate funding gaps, especially to secure funding to deliver additional capacity – which is key to accommodate the Net Zero transition and ensure we effectively play our role in its delivery.

Ofgem has not provided the analysis it used to establish appropriate thresholds. Neither has Ofgem provided evidence to justify a higher threshold in electricity distribution (ED) than in gas distribution (GD) and transmission (T).

Table 1 - Comparison of materiality thresholds in RIIO-ED2 and GD&T2

	ED (proposed)	GD	T
Materiality threshold, as % base revenue and after TIM	1%	0.5%	0.5%

We also consider that the inability to aggregate projects is problematic. It effectively acts as a barrier to flexibility and may create cost inefficiencies. It will prevent us from adopting an agile approach and taking smaller initiatives

to incrementally respond to changes on the network as we will not be able to secure funding for those. We elaborate on this point in our response to Core-Q4.

We think that the threshold should be set at 0.5% of base revenue, in line with the transmission and gas distribution sectors. We also think that the inability to aggregate projects should be removed. Provided that there are suitable controls around the provision of additional funding, we do not see why aggregating projects should not be allowed.

Approach to the Totex and Business Plan Incentive Mechanisms

Q7. Do you agree with our view that all the DNOs have passed Stage 1 of the BPI?

We disagree with Ofgem's view that all DNOs met the minimum requirements set under stage 1 of the Business Plan Incentive (BPI). The current position, if left unchanged, signals to DNOs that minimum requirements are not "must haves" as there is no consequence from ignoring Ofgem's guidance. That sets a damaging precedent and is demoralising for those organisations that followed Ofgem's guidance and ensured every requirement was met.

The purpose of stage 1 of the BPI assessment is to ensure that the network businesses have a strong incentive to submit a business plan that meets the basic requirements set by the regulator. These minimum requirements should be "must have", non-negotiable elements of the business plan.

Moreover, as the Overview Document makes clear, Ofgem's materiality assessment should have taken account of *"the extent to which [Ofgem's] ability to set the RII0-ED2 price control has been compromised by the failure(s)"* and *"any consumer detriment that may be expected as a result of the failure(s)"*.

On page 72 of the Overview Document, Ofgem explains that:

- One DNO failed to meet the minimum requirements for whole system solutions. Given the critical role that whole system solutions will play in the transition to Net Zero, including as a result of the way that developments in transport and heat will impact on electricity sector. It would be helpful to understand why Ofgem judged this DNO to have passed stage 1, with no penalty;
- Another DNO did not meet the minimum requirements for its Distribution System Operation (DSO) Strategy or for whole system solutions. Given the pivotal role that Ofgem envisages for the DSO and for whole system solutions. It would be helpful to understand why Ofgem judged this DNO to have passed stage 1, with no penalty; and
- Two other DNOs did not meet the minimum requirement to measure the effectiveness of strategy and pay/reward structure. This minimum requirement was targeted at the important aim of maintaining and building trust in the energy sector. Given their shortcomings, it would be helpful to understand why Ofgem judged these two DNOs to have passed stage 1, with no penalty.

In our view, there is a risk of discrimination between treating unlike DNOs as though they were alike. Those who did not meet the minimum requirements should have faced a penalty in accordance with Ofgem guidance.

This is yet another example of the lack of alignment between the strategic context, Ofgem's Business Plan Guidance and the outcomes of the Draft Determinations.

Q8. Do you agree with our overall approach regarding treatment of CVP proposals?

We disagree with Ofgem's overall approach for the treatment of Consumer Value Proposition (CVP) proposals.

- **We disagree with Ofgem accepting and rewarding a CVP on Personal Resilience Plans which unfairly rewards a DNO for an activity that is business as usual (BAU) by UK Power Networks.** Why should this DNO's customers pay for a service that UK Power Networks' customers will receive in our standard service offering?

Ofgem states that “it considers the provision of vouchers for battery packs for all eligible PSR1+ customers to go beyond BAU and provides demonstrable customer benefit”³, and therefore accepted the proposed CVP. However, we have made a similar proposal as part of our BAU activity as we committed to dispatch battery banks to our medically dependent Priority Service Register (PSR) customers who are at risk of being without power for more than four hours between 2024 and 2028⁴. We think Ofgem should accept (this part of) the DNO’s CVP without reward, to ensure consistent and fair treatment of DNOs’ CVPs, or alternatively reward UK Power Networks on the same basis as this other DNO has been rewarded. Otherwise, there is a risk of discrimination by not treating all DNOs on the same basis;

- **In principle we agree with Ofgem’s proposal to fund our proposed CVP for off-gas grid as a Price Control Deliverable (PCD), but Ofgem’s approach will underfund our plan.** Ofgem has inappropriately dissociated our proposal by funding our programme of capacity release but excluded the £1.5 million of costs associated with our proposed programme of coordinated engagement, education, advice and referrals to off-gas grid communities to promote the uptake of energy efficiency and heat electrification. As a result, capacity requirements, and therefore network investment, will be higher than we anticipated in our proposal. Ofgem should either increase our allowance to enable us to deliver the required capacity or accept that the delivered capacity will be lower and therefore fewer customers will be able to transition to electric heating. Moreover, it is not clear why Ofgem has ruled out funding for us when another DNO has had a similar scheme accepted with reward under the CVP methodology. We have detailed our views further in our response to UKPN-Q5; and
- **We disagree with Ofgem’s position on our consumer vulnerability fuel poverty support programme.** Ofgem has refused to fund our programme and gave us no funding for fuel poverty support but allowed over £36 million of ex-ante funding to other DNOs for similar activities. This evidence has been provided to Ofgem through our bilateral discussions. We are very concerned with the discriminatory approach to UK Power Networks’ funding when compared to other DNOs. On top of this, Ofgem is proposing to hold us to our vulnerability targets – although it has not provided us with the funding to deliver. We consider that this is an error which needs to be corrected. We request fair and consistent treatment between DNOs. Ofgem should allow £9 million to fund our proposal in our ex-ante allowance. We detail our views further in our response to UKPN-Q7.

Increasing competition

Q9. Do you agree with our proposed position on early and late competition?

We agree with Ofgem’s proposition on early and late competition.

RIIO-ED2 in the round, post appeals review and pre-action correspondence

Q10. Do you have any views on the proposed scope of the Final Determinations Questions (FDQ) process and pre-action correspondence, including on the proposed timing for sending such to Ofgem?

We agree that some degree of pre-action correspondence at the appropriate time may be beneficial for all parties. However, we do not agree with the scope and nature of pre-action correspondence currently proposed by Ofgem in its Draft Determinations.

The nature and role of pre-action correspondence is well understood in the context of other forms of litigation. However, all such pre-action correspondence has three features:

- The correspondence comes after the event (in this case the final decision) that creates the ground for legal action;

³ RIIO-ED2 Draft Determinations, SSEN Annex, Table 17,

⁴ Commitment VS6 of our RIIO-ED2 Business Plan

- The purpose is to allow the party whose decision is being challenged to understand the case so it can reconsider its position, make amendments, and avoid the time and expense that would result from the litigation; and
- Consistent with the above, such correspondence is two-sided so that the potential claimant receives a response so it can understand the defence that will be advanced by the other party, and therefore is in a position to make an informed decision about proceeding with the claim.

Ofgem's proposal does not reflect these features. The decision that would be subject to statutory appeal is the decision to modify the conditions of a licence. However, Ofgem has proposed that pre-action correspondence setting out, in sufficient detail, the alleged errors and the elements of RIIO-ED2 price control that are being appealed should be sent to Ofgem *before* Ofgem publishes its decision on licence conditions. Consequently, Ofgem appears to be proposing that it ought to be notified of the grounds of appeal before any grounds of appeal can have arisen in law.

The final decision is the decision to modify the conditions of licences which will give effect to the Final Determinations and until such decision is made, Ofgem is required by law to continue to consult in accordance with all of the standards applicable to a fair consultation process (which includes taking into account representations made by all interested parties). Therefore, the Final Determinations should not be treated as the trigger point for a pre-action letter as that is incompatible with Ofgem's duty to consult.

In RIIO-GD2, the Final Determinations were published on 8 December 2020, the statutory consultations on the proposed modification to network companies' licence conditions to give effect to the RIIO-GD2 price control took place from 17 December 2020 to 19 January 2021 and the decision on licence modifications was published on 3 February 2021. We assume a similar process will be followed for the RIIO-ED2 price control and the process for pre-action correspondence proposed by Ofgem would mean that the Final Determinations would (incorrectly) be the trigger for submitting pre-action correspondence while the statutory consultation is ongoing in relation to the proposed modification to network companies' licence conditions and the decision on licence modifications is still pending.

Ofgem's approach implies that the consultation on the proposed modifications of the licence is a formulaic exercise whereas it is a statutory consultation and is subject to all of the statutory and other legal duties attaching to any such process.

While Ofgem notes this will allow us to '*narrow issues and, in some cases, to avoid appeal grounds entirely*' it does not state that this will be by way of giving Ofgem an opportunity to amend its position. It further notes that pre-action correspondence in RIIO-GD&T2 was successful in allowing '*parties involved to resource appropriately*' which shows that on the contrary the purpose appears to be to give Ofgem more preparatory time. That is not a proper basis for pre-action correspondence.

Ofgem appears to view the pre-action correspondence process as a unilateral exercise, imposing obligations on appellants but not itself. The conventional reason for pre-action correspondence is meant to encourage parties to resolve differences without going to court. It is difficult to envisage how the pre-action correspondence would encourage Ofgem or potential appellants to resolve differences without going to the Competition Markets Authority (CMA) given there are no obligations on Ofgem.

Ofgem emphasises two separate points made by the CMA in the CMA letter of 30 October 2019. The first is that the CMA would welcome prior notification of the likelihood of appeals, including their potential scope. This is for the benefit of the CMA itself so as to allow it to understand in advance the resource commitment that it may be required to make in determining one or more appeals. The second is that the CMA encourages what it calls 'active engagement' between potential appellants and regulators as a form of 'good practice'.

These are distinct requirements. So far as Ofgem is concerned, active engagement, at least on the part of the companies, is a feature of the entire RIIO-ED2 price control process and does not require pre-action correspondence. By the time Ofgem makes the final decision, it would have had several opportunities to address the concerns of the companies and avoid risk of dispute. Therefore, this is unlike judicial review cases in which pre-action correspondence is required as otherwise Ofgem would be unable to make amendments to its position and avoid dispute.

We also note that the CMA does not purport to require pre-action correspondence of the sort that Ofgem envisages. The CMA letter provides that it would 'ideally' prefer the pre-notification of appeal to include the

potential scope of appeal, however, Ofgem's requirements in relation to the pre-action correspondence go far beyond the CMA's stated expectations.

We will continue to engage extensively with Ofgem during the price control process but we do not agree with the timing and scope of the pre-action correspondence proposed in the Draft Determinations. It follows from the above that Ofgem's proposal on pre-action correspondence is contrary to established litigation principles and introduces unnecessary and burdensome requirements to the process.

Access and Forward-looking Charges Significant Code Review

Q11. Do you agree with our proposal to not introduce a specific uncertainty mechanism to manage the impact of the Access SCR (and address it through the LRE mechanisms instead)? Please explain why.

We agree with the proposal not to introduce a specific Uncertainty Mechanism (UM) to manage the impact of the Access Significant Code Review ("Access SCR").

However, we would like to see a clear methodology for how Ofgem will normalise DNO totex submissions on a consistent basis, noting that the initial impacts of access and charging by DNOs led to widely different ranges which is not credible. The normalisation process must consider the peak demand impact of Low Carbon Technologies (LCT) and the trigger levels that DNOs intervene to build more capacity. This evidence has been provided to Ofgem. For example, one DNO estimated the impact of the access SCR between £177 million and £752 million despite only having one licensed network. In comparison, UK Power Networks' best view was £160 million with three licensed networks.

In addition, our support for not having a specific UM for access and charging is predicated on ex-ante allowances being set appropriately, and load-related UMs being fit-for-purpose. We have strong concerns about both points, which we explain respectively in our responses to Core-Q3, Core-Q4 and Core-Q5. On the load-related UMs, we have identified the following issues:

- They do not cover the full range of costs to deliver the capacity output;
- They preclude flexibility and distort investment decision making at the detriment of customers; and
- The proposed capitalisation rate is incorrect and not reflective of the costs to deliver.

The overall impact of the above is that an ambitious DNO that has followed Ofgem's guidance on utilising UMs⁵ is disadvantaged compared to other DNOs that have much larger ex-ante increases baked into their allowances which pushes up the costs for customers in respect of their baseline charges. We do not understand how this is in the interests of customers who may be funding work which is not required or creating opportunities for outperformance in baseline totex for work and services which do not turn out to be required. This is also yet another example of the lack of alignment between Ofgem's guidance and the Draft Determinations.

Finally, we note the introduction of curtailment costs as part of the access and charging reform. There is still, at what is quite a late stage, a lack of detail on the arrangements for curtailment payments and how they will be funded. We are committed to working with Ofgem as part of a working group to work out these details and deliver a tidy delivery of the Access SCR.

QUESTIONS IN THE DRAFT DETERMINATIONS - CORE METHODOLOGY DOCUMENT

Embedding the consumer voice in RIIO-ED2

Core-Q1. Do you agree with our proposals for the enduring role of the CEG?

We agree with Ofgem's proposal for the enduring role of the Consumer Engagement Group (CEG), provided that the CEG's views are effectively taken into account by Ofgem in its Draft Determinations. The CEG and Challenge group have helped challenge our thinking and provided valuable input to the development of

⁵ RIIO-ED2 Business Plan Guidance, paragraphs 5.14 to 5.20

our Business Plan. We were disappointed to see that the CEG supported our Business Plan, in particular on energy efficiency support and fuel poverty support, but Ofgem rejected our proposals in these areas. We agree with Ofgem's proposal to allow DNOs to set the scope and remit of their CEG for RIIO-ED2 as appropriate to their regional context and business needs.

Core-Q2. Do you see value in the CEGs working together to deliver more coordinated and comparative reporting on some of the DNOs' Business Plan commitments?

Ofgem's consultation position is for DNOs to determine whether they retain the CEGs during RIIO-ED2. We welcome this.

It is for companies to determine the right approach for their regional and business context. Therefore, **it is not immediately clear what comparative reporting CEGs could undertake that Ofgem is not already implementing within the price control framework.** We believe that comparative reporting is a role that Ofgem should perform and not the CEGs because of the expertise, capacity and guidance needed to undertake meaningful comparisons.

Networks for Net Zero

Core-Q3. Do you agree with our proposal to adjust allowances to £2.68 billion to account for the concerns highlighted by our assessment?

We think that Ofgem's Draft Determinations fail the stated objective to deliver Net Zero at the lowest cost to customers. Ofgem is insufficiently ambitious and fails to take into account interdependencies in four key areas: Load-Related Expenditure (LRE) assessment, load normalisation, load-related UMs and the DSO incentive. Aligning these four areas is key to ensuring that the regulatory framework contributes to delivering Net Zero at the lowest cost to customers. We present our views on the load normalisation process below.

We do not agree with Ofgem's proposed adjustment. Ofgem's methodology has serious limitations for the following key reasons:

1. **Ofgem relies on DNO-led LCT forecasts which has led to unrealistic results.** For example, Ofgem's forecast is that by the end of RIIO-ED2, 18% of LCTs will be connected to our network (in this case referring to EV charge points and heat pumps). Today, that number is already 28% of the total share of LCTs and there is no evidence to suggest why this is likely to change over the coming years;
2. **Ofgem's approach to defining alternative drivers as part of the LRE demand adjustment is flawed as it depends on DNO-led data instead of coming from independently verifiable sources.** Furthermore, Ofgem has not set a consistent baseline year when using DNO data e.g. for UK Power Networks' networks Ofgem uses data going back to 2013 whereas for another DNO's networks it uses data from 2020. This means that adjustments are being made on inaccurate and inconsistent LCT assumptions;
3. **Ofgem's approach to forecasting demand uses DNO-submitted data on the forecast installed capacity of LCTs.** This vastly overestimates DNOs' requirements as actual demand is not equal to installed capacity. Ofgem has also included technologies such as Solar PV as a proxy for demand even though this is generation;
4. **Ofgem has failed to factor-in the different split of underground and overhead cable that DNOs will be reinforcing.** As underground cables are more expensive than overhead cables (as the evidence provided indicates), this disadvantages LPN which uses underground cable for almost all of its network area;
5. **Ofgem has used a mean average to benchmark low voltage (LV) / high voltage (HV) circuit reinforcement volumes and Distribution Transformer volumes.** The mean value is a poor measure of average volumes given the significant variance between DNOs' submitted volumes;
6. **Ofgem only uses a one-way ratchet to remove reinforcement volumes from DNOs, yet uses a two-way ratchet for unit cost adjustments.** This inconsistency leads to DNOs such as UK Power Networks being disadvantaged for submitting an efficient level of volumes. Overall, when combined with the above points, Ofgem's disaggregated benchmarking approach provides an advantage to DNOs who have over forecasted and submitted inefficient volumes; and

- 7. Both for disaggregated and totex benchmarking, Ofgem uses charge points alongside heat pumps as an indicator of the demand impact from LCTs.** We think that Ofgem should use EVs rather than charge points. EVs are a more reliable indicator of the demand impact from LCTs than charge points as DNOs use different ratios of EVs per charge points and EVs vary less in size and type than EV charge points. This is would also be consistent with the approach used in the Future Energy Scenario and Distribution Future Energy Scenarios demand growth models.

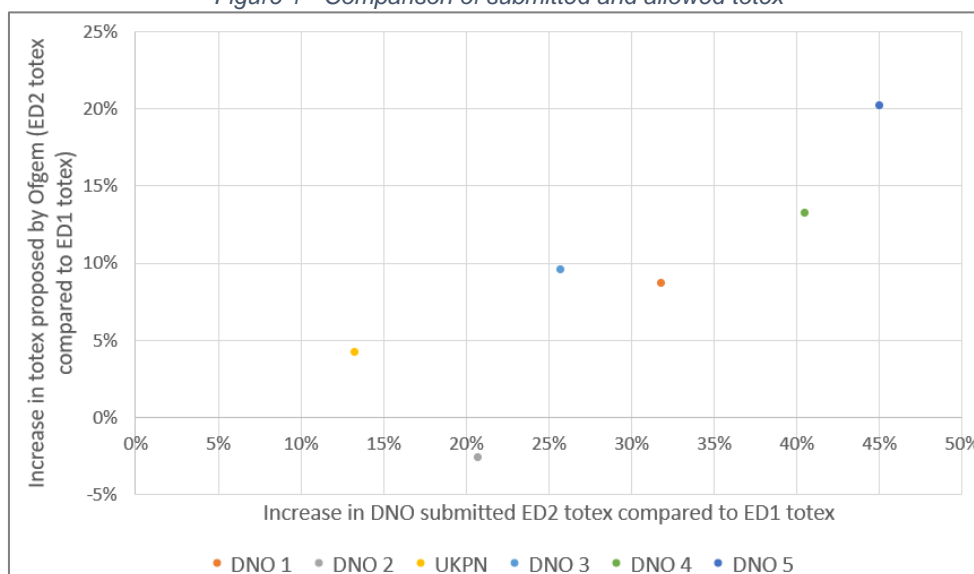
In the table below we summarise how the above issues can be resolved ahead of Final Determinations. Our supplementary document “Normalising LRE to benchmark submissions” contains more detail on the disaggregated normalisation process we recommend Ofgem takes for secondary reinforcement.

Table 2: Recommended resolutions to the identified issues with Ofgem's LRE benchmarking

Current issue with Draft Determinations methodology	Proposed solutions
Does not accurately reflect the demand impact from LCTs	<p>Use EVs instead of charge points</p> <p>Only use EVs and Heat Pumps i.e. do not include other LCTs such as Solar PV</p> <p>Use industry-based factors of 0.6kW/EV and 0.8kW/Heat pump to estimate regional peak demand</p> <p>Use actuals to set EV and Heat Pump forecasts for all benchmarking</p>
Adjustment treats all circuit types equally and does not account for differences between the mix of underground and overhead circuit	Use more granular data to assess unit costs for underground and overhead circuits at LV and HV.
Use of mean average to calculate “efficient” reinforcement activities per LCT generates distorted results	Use industry median to get a more accurate average for both transformers and circuits
The volume ratchet disadvantages DNOs that have submitted efficient reinforcement volumes	Use a bi-directional ratchet that is consistent with unit cost adjustments
There is no consideration of existing network utilisation, which will influence volume requirements	This cannot be fixed now as DNOs do not have sufficient data on actual LV utilisation. However, the volume driver metrics will allow DNOs to collect utilisation data in RIIO-ED2 which could then be used in RIIO-ED3
There is no consideration of the variation between transformer sizes and cable lengths at the DNO level, which could distort adjustments	<p>This cannot be fixed now due to insufficient data availability and the additional complexity involved is unlikely to be proportional to the benefit as the variance between DNOs will not be very significant</p> <p>Including a volume driver metric that uses a bespoke transformer/circuit ratio for each DNO can help address this issue</p>
The demand adjustment approach uses DNO-led data that uses different and inconsistent data sources to estimate the number of LCTs deployed.	The recommended approach to forecasting used in our proposed benchmarking process presented in our “Normalising LRE to benchmark” supplementary document should also be used for Ofgem’s LRE demand adjustment i.e. in place of the current alternative drivers approach.

Overall, Ofgem’s approach rewards DNOs which over forecasted and requested high ex-ante allowances, as shown in the figure below. This is another example of the lack of alignment between Ofgem’s guidance and the financial outcome from the Draft Determinations. It sends a strong signal to DNOs for RIIO-3 that the more you ask for, the more you get, which is counter to the interests of customers.

Figure 1 - Comparison of submitted and allowed totex

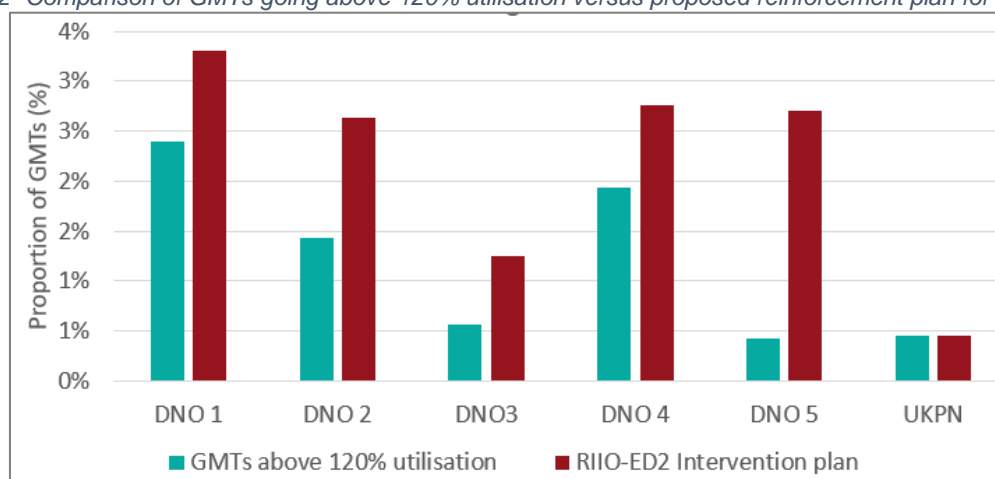


With our suggestions to improve the load normalisation, Ofgem could save customers an additional £300 million on secondary reinforcement, compared to the approach used in the Draft Determinations. Our recommended normalisation approach would lead to DNOs being allowed £385 million to reinforce LV/HV circuits and Distribution Transformers, which is in line with RIIO-ED1 spend levels and would better reflect high confidence requirements due to LCT-related demand that DNOs will face over RIIO-ED2.

We have also modelled several alternative normalisation approaches, which are provided to Ofgem in our “Normalising LRE to benchmark submissions” supplementary document. These would result in savings of between £285 million and £494 million. The majority of these savings come from reductions to work volumes. If higher volumes were required, the secondary reinforcement volume driver would ensure that DNOs are funded in a timely manner to deliver the work.

There is evidence that DNOs significantly invest ahead of need, and possibly in a speculative way. By cutting volumes, Ofgem would encourage DNOs to be demand-led when reinforcing unless there is compelling evidence to undertake investment ahead of need. For example, it is a common engineering standard that only Ground Mounted Transformers (GMTs) which have reach 120% utilisation or more need reinforcement. Yet, the figure below shows that RIIO-ED2 proposed intervention plans go much beyond that. We think Ofgem should separate investment ahead of need volumes and require DNOs to submit separate justification for these (as well as coupling the funding for this investment with a PCD, to ensure delivery).

Figure 2- Comparison of GMTs going above 120% utilisation versus proposed reinforcement plan for RIIO-ED2



Core-Q4. Do you agree with our proposed secondary reinforcement volume driver and LV services volume driver and the associated controls?

We think that Ofgem's Draft Determinations fail the stated objective to deliver Net Zero at the lowest cost to customers. Ofgem is insufficiently ambitious and fails to take into account interdependencies in four key areas: LRE assessment, load normalisation, load-related UMs and the DSO incentive. Aligning these four areas is key to ensuring that the regulatory framework contributes to delivering Net Zero at the lowest cost to customers. We present our views on the load-related UMs below.

We welcome the introduction of volume drivers to automatically flex LRE during the price control as capacity needs become clearer. With respect to the secondary reinforcement volume driver, we agree with Ofgem's intention to include robust monitoring and controls as a way of ensuring an efficient level of allowances is released. This will protect customers from DNOs seeking to grow their RAV by overinvesting in network capacity. One of the key metrics being proposed is around the ratio of circuit-related volumes (kms) as a proportion of distribution transformer volumes (GMTs and Pole Mounted Transformers (PMTs)).

Our analysis, which is explained in our supplementary document "the relationship between secondary level transformer and circuit reinforcement", demonstrates that there is a strong correlation between transformer and circuit reinforcement needs, which are both driven by LCT-related demand. As DNOs will be acquiring and reporting more accurate data on transformer utilisation, we believe that - as there is a lack of direct data on circuit utilisation - this ratio of interventions will be an important metric to prevent overinvestment in LV or HV circuits. We look forward to working further with Ofgem on this and the wider set of controls being considered.

However, we have significant concerns about the scope and parameters of the proposed volume drivers, in particular:

- The exclusion of flexibility solutions from the secondary reinforcement volume driver;
- The level of unit costs, which are not cost-reflective;
- Ofgem's choices on unit costs and capitalisation rates will disadvantage DNOs who have submitted the most ambitious plans in line with Ofgem's own Business Plan Guidance; and
- With regards to LV services volume driver, we have concerns with the way Ofgem has set out unit cost allowances with respect to the sub-categories.

We provide more details views below.

1. We strongly disagree with the exclusion of flexibility solutions from the secondary reinforcement volume driver

Ofgem states that “the scope of the proposed secondary reinforcement volume driver encompasses the majority of the investments needed on the lower voltages of the network. However, it does not include a volume measure for flexibility spend on the lower voltages”⁶. Ofgem recognises that this might lead DNOs to prefer reinforcement even when flexibility solutions are available but that “the inclusion of robust monitoring and controls combined with wider price control measures will help maintain strong incentives to pursue flexibility options. Our proposed DSO incentive design should also drive DNOs to maximise their use of flexibility”⁷.

We do not think that the monitoring and controls and the DSO incentive Ofgem refers to will be sufficient to counter the tendency and bias for DNOs to prefer reinforcement:

- First, ex-post monitoring and controls cannot effectively offset a strong financial incentive. We also note that out of the four metrics Ofgem proposes to use to monitor the use of flexibility, two (LCT growth and a broad measure of load growth) will provide little or no meaningful information on whether DNOs have unduly overlooked flexibility solutions;
- Second, we consider the DSO incentive is significantly under-powered. At 0.2% of RoRE which equates to approximately £5.5 million for UK Power Networks, the incentive is not powerful enough to offset the financial gains from building assets. Moreover, the proposed DSO incentive that focuses specifically on flexibility market testing, is only a small proportion of the total incentive. Ofgem indicates they will “validate the extent to which a DNO is undertaking comprehensive quantitative assessments when determining if distribution flexibility services are the most economical solution with respect the reinforcement decisions”⁸. However, this metric is only one of the three outturn performance metrics retained in the DSO incentive, which together weigh only 20% of the overall incentive. Overall, the DSO incentive is at odds with the secondary reinforcement volume driver, which will not provide allowances for flexibility; and
- In fact, under current rules DNOs will have zero incentive to procure LV flexibility during the RIIO-ED2 period as this would result in a claw back (the volume driver only recognises reinforcement activities).

We provide further views on the DSO incentive in our response to Core-Q24.

Overall, we are concerned that the Draft Determinations do not sufficiently incentivise flexibility and delivering Net Zero at the lowest cost to customers. Increasing flexibility on the network is crucial for networks to accommodate Net Zero at lowest costs. The Carbon Trust and Imperial College London estimated that deploying flexibility technologies could save the GB between £17 billion and £40 billion from 2015 to 2050⁹. Delivering increased levels of flexibility will require large technical and cultural change from DNOs, which therefore needs to be strongly incentivised. The Draft Determinations, as they are, mean that the regulatory framework acts as a blocker to the development of flexibility in GB.

We think Ofgem should consider taking the following steps to remedy this:

- Allow flexibility to be treated equivalently to reinforcement by setting a £/MVA deferred for flexibility that means DNOs are focused on outputs instead of inputs. We have set out a more detailed proposal in our “Treatment of secondary level flexibility in uncertainty mechanisms” supplementary document;
- Increase the value of the outturn performance metric on flexibility in the DSO incentive so that it is more significant. As a minimum, Ofgem should create a DSO outturn metric that has sufficient upside potential to encourage DNOs to procure innovative LV flexibility services that are currently nascent; and
- Consider introducing a separate sharing factor for flexibility spend, for example 60/40 – with DNOs being allowed to retain 60% of underspend on flexibility, whilst customers would share the remaining 40%. We think this would send a strong signal to DNOs to proactively develop flexibility solutions. Thus far, Ofgem’s

⁶ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 3.57

⁷ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 3.62

⁸ RIIO-ED2 Draft Determinations, Core Methodology, Table 10

⁹ The Carbon Trust (2016), An analysis of electricity system flexibility for Great Britain

own analysis shows that UK Power Networks has included more than double the amount of flex in its Business Plan than all of the other DNOs combined. Ofgem needs to ask itself, why?

In summary, Ofgem needs to review the ex-ante LRE proposals from DNOs, the sharing factor for load underspend, the DSO incentive and the UMs as an overall integrated package with sharp incentives that reward high performing DNOs and penalise laggard DNOs that build assets at the expense of customers with little or no justification. RIIO-ED2 present an opportunity to establish a strong foundation for facilitating Net Zero and it should be taken by Ofgem.

2. The unit costs in the secondary reinforcement volume driver are not appropriate and should distinguish between overhead and underground circuits

In Table 3 of the Core Methodology document, Ofgem proposes to use a single unit cost for all LV circuits and another single cost for all HV circuits, regardless of whether those circuits are overhead or underground¹⁰. This is an error given that there is sufficient evidence which proves that underground circuits are more expensive than overhead circuits. This is clearly evident in the asset replacement analysis undertaken by Ofgem, where the median RIIO-ED2 unit cost for LV overhead line work is £21.9k per km, whilst the LV underground main (plastic) unit cost is £107.9k per km. Similarly, at HV the respective RIIO-ED2 median unit costs for 6.6/11kV overhead lines and underground circuits are £25.4k per km and £119.8k per km. However, Ofgem has not sought to disaggregate the two costs in its unit cost analysis for secondary reinforcement. This has led to errors, which are particularly pronounced in the case of London (which has almost exclusively underground cables).

Ofgem must introduce a different unit cost for overhead and underground circuits. This will ensure consistency with Ofgem's decision related to LV services volume driver.

3. Ofgem's choices on unit costs and capitalisation rates will disadvantage DNOs who have submitted ambitious plans

As with other areas of the Draft Determinations, we find that some of Ofgem's decisions on the volume drivers will disadvantage DNOs who have followed Ofgem's guidance and submitted ambitious plans with realistic ex-ante allowances.

First, we disagree with the exclusion of indirect costs from the volume drivers. In effect, the volume drivers will only partially fund DNOs for their additional LRE. As a result, DNOs which have requested high ex-ante allowances based on high LRE forecast will have both their direct and indirect costs funded. In contrast, DNOs who submitted plans which rely more on volume drivers to fund their LRE expenditure will only be partially funded. This creates an asymmetry that is unfair, discriminatory, and ultimately detrimental to consumers as it disincentivise the submissions of ambitious, cost-effective plans. This is yet another example of a lack of alignment between the Business Plan Guidance and the Draft Determination outcome.

Second, we disagree with the capitalisation rates. Ofgem has set a capitalisation rate of 98% for re-openers and volume drivers, compared to between 68% and 80% for ex-ante allowances (as shown in table 21 of Finance Annex). This means that DNOs who have proposed low ex-ante allowances and rely more on volume drivers (following Ofgem's guidance) will have relatively greater proportions of "slow money" than DNOs with high ex-ante allowances.

To remedy these issues, Ofgem should:

- Included indirect costs in the volume drivers, to ensure that DNOs are funded on the same basis as those who have their costs funded in ex-ante allowances; and
- Set the identical capitalisation rates for ex-ante and ex-post funding to ensure that there is no discrimination in terms of adequacy of funding between the two funding approaches.

¹⁰ RIIO-ED2 Draft Determinations, Core Methodology, Table 3

4. With regards to LV services volume driver, we have concerns with the way Ofgem has set out unit cost allowances with respect to the sub-categories

We have two key concerns:

- **The unit cost allowance does not cover the full range of relevant activities.** It is notable that Ofgem has not set unit costs for unlooping services, despite mentioning these as a key activity that DNOs should be undertaking. As explained below, Ofgem also seems not to have set unit costs for fuse upgrades properly; and
- **The unit cost allowance is too low.** We suspect that Ofgem has included the Fuse upgrade costs under Cut Out (metered). Cut Outs should include replacing both the fuse and the Cut Out itself and will therefore be higher, in our view, than the £250/unit that Ofgem has provisionally allowed.

In acknowledgment of Ofgem recently requesting from us and other DNOs a more complete breakdown of LV service activity costs and volumes, we support Ofgem undertaking further work in this area. As part of this review Ofgem can determine what the appropriate unit costs are for the full range of LV Service activities. We look forward to working with Ofgem to achieve this ahead of Final Determinations.

Core-Q5. Do you agree with our proposed LRE re-opener?

We think that Ofgem's Draft Determinations fail the stated objective to deliver Net Zero at the lowest cost to customers. Ofgem is insufficiently ambitious and fails to take into account interdependencies in four key areas: LRE assessment, load normalisation, load-related UMs and the DSO incentive. Aligning these four areas is key to ensuring that the regulatory framework contributes to delivering Net Zero at the lowest cost to customers. We present our views on the LRE re-opener below.

We welcome the introduction of a LRE re-opener, as a complement to the volume drivers. However, we have a few concerns about its design, which we explain below.

1. We have concerns about the re-opener window, currently set in year 3 of the price control, April 2025.

We think that the window is too late and will not allow DNOs to secure funding for LRE in a timely manner. Assuming a 15-month time lag between the re-opener window and any consequential increase in tariffs (which would be a standard time lag period based on previous experience), we would only start to obtain funding in July 2026. Such a time lag is not appropriate given the uncertainty surrounding LRE expenditure, which is further compounded by the impact of the Access SCR and the scale of future curtailment costs which are difficult to quantify. Given the uncertainty and scale of LRE costs, it is essential that DNOs can secure additional funding promptly to fund additional LRE and so as not be a blocker to the Net Zero transition.

We propose introducing an annual window, starting from year-2 of RII0-ED2. We think that this will provide sufficient flexibility to secure additional funding as needs become clearer.

2. We disagree with the materiality threshold

We provided views on the 1% materiality threshold in our response to Q6. We think a lower threshold of 0.5% of base revenue after TIM should apply and that it should be possible to aggregate projects.

There should also be expedited approval for smaller requests, in particular in cases where the DNO has exhausted its ex-ante allowance for a load-related project and was not able to secure additional funding through the volume driver. The LRE re-opener should be designed to be used for these situations and allow DNOs to fund flexibility investments.

3. We seek clarity on how Ofgem would trigger the LRE re-opener

If Ofgem intends on having the ability to trigger the LRE re-opener in a similar way to the Net Zero re-opener, we should have clarity on what factors would lead to this and the windows within which it could be used. Ofgem's Draft Determinations removed the RIIO-ED1 LRE re-opener that contained a set of trigger points and windows. It is imperative that DNOs are consulted on reinstating these or any new parameters.

4. Overall, we are concerned that the LRE re-opener may further disincentivise flexibility investments, or acts as a blocker to them

Ofgem states that DNOs should rely on ex-ante allowances to procure flexibility and that it does not expect flexibility expenditure to lead to the triggering of an UM. We are concerned with the logic of this position, as it should not matter whether flexibility or reinforcement is deployed. It is entirely feasible that a DNO undertakes a combination of flexibility and reinforcement which is to meet higher than expected demand increases i.e. a higher than forecasted release of network capacity outturns. If Ofgem only assesses costs and does not factor in volume delivery relative to requirements, there is a risk that it is eroding any incentive for the DNO to be cost efficient.

This issue can be resolved by Ofgem examining the volume of capacity the DNO has delivered versus planned, as well as the trajectory relative to the network utilisation level (via the Load Index). Ofgem can then set an appropriate unit cost (£/MVA) based on the blend of activities undertaken.

Core-Q6. Do you agree with our proposed approach to the Net Zero re-opener?

We welcome the introduction of a Net Zero re-opener. However, there are material gaps that need to be addressed by Ofgem – specifically related to local government triggers and process. The Net Zero re-opener can only be triggered by Ofgem, based on evidence and advice provided by the Net Zero Advisory Group (NZAG). The NZAG is dominated by national and devolved authorities - no local authority is represented in the NZAG. We are concerned that this risks local considerations not sufficiently being taken into account.

The Local Authority Energy Planning (LAEP) process may result in a number of requests for accelerated strategic investment including "whole system" investment which benefits transport and heat stakeholders and is socially desirable but might not otherwise be prioritised on electricity network terms alone.

It is acknowledged across Government and beyond, that local government has a key role to play in driving the Net Zero agenda, as is reflected in strategies and policies for Heat Networks and for EV charging. The Climate Change Committee noted in a recent report that the *"sixth carbon budget can only be achieved if Government, regional agencies and local authorities work seamlessly together. [...] Top-down policies go some way to delivering change but can achieve a far greater impact if they are focused through local knowledge and networks"*¹¹. For this to be meaningful, local authority decisions must have consequences, including an ability to drive utility investment in certain circumstances. DNOs must therefore be enabled to respond, and the Net Zero re-opener must be explicitly tasked with facilitating this response, where necessary.

We have a particular concern about being equipped to meet the Mayor of London's (MoL) climate ambitions in the absence of a specific re-opener for this, which Ofgem has rejected. So far, the MoL's Net Zero vision has not yet been translated into specific investment projects across London Boroughs, except, to a limited extent, by Transport for London in respect of EV charging policy. However, we expect coordination to grow and firmer plans to come forward over RIIO-ED2 in response to the MoL's target for London to reach Net Zero by 2030.

It is unclear how the NZAG would react to a London-specific investment plan or to strategic investment needs arising from a comprehensive LAEP. We have discussed this issue with the Greater London authority (GLA) and understand that they have reflected similar views in their response to Ofgem's Draft Determinations. Jointly, we believe that DNOs and local authorities must have the right to trigger the Net Zero re-opener too. This would

¹¹ Climate Change Committee (2020). Local Authorities and the Sixth Carbon Budget.

require Ofgem to set a clear process and timeline that quickly unlocks additional allowances to deliver network capacity requirements should these be deemed justified.

Finally, as explained in our response to Q6, we disagree with the application of a common 1% materiality threshold. Almost all investment projects emerging out of local authority engagement are likely to be below the 1% materiality threshold for UK Power Networks as a whole or even for the individual networks. The proposed materiality threshold means that the Net Zero re-opener will not fulfil its purpose. We request that Ofgem lowers the threshold to 0.5% of base revenue and allows the aggregation of projects.

Core-Q7. Do you agree with our proposed approach to the value of the SIF?

We agree with Ofgem's approach to the value of the Strategic Innovation Fund (SIF). Retaining the option to review the need for additional funding is also sensible.

Core-Q8. Do you agree with our proposed approach to weighting SSMD criteria and benchmarking RIIO-ED2 NIA requests against RIIO-ED1?

We agree with Ofgem's approach to weighting Sector Specific Methodology Decision criteria and benchmarking RIIO-ED2 NIA requests against RIIO-ED1.

Core-Q9. Do you agree with our proposed approach to setting NIA allowances?

We agree with Ofgem's approach to setting NIA allowances, subject to our views on the SIF, covered in our responses to Core Q7 and Core-Q8 above.

Core-Q10. Do you agree with our proposal to allow DNOs to carry over any unspent NIA funds from the final year of RIIO-ED1 into the first year of RIIO-ED2?

We agree with Ofgem's proposal to allow DNOs to carry over unspent NIA funds from the final year of RIIO-ED1 into the first year of RIIO-ED2. And we understand this to be applicable to all RIIO-ED1 projects, including those that span price controls. This will ensure projects currently in flight and destined to deliver value to customers are able to continue across regulatory cycles. This will also reduce the administrative burden on DNOs to close and register new RIIO-ED2 NIA projects.

Core-Q11. Do you agree with our proposed approach for the Annual Environmental Report ODI-R?

We broadly agree with the proposed approach for the Annual Environmental Report Reputational Output Delivery Incentive (ODI-R). However, reporting requirements should remain as simple as possible, while meeting stakeholders' requirements for comparable reporting. As we expressed in working groups, the current guidance is overly prescriptive. We think that the guidance for the vulnerability incentive is an example of a more proportionate approach.

Core-Q12. What are your views on the proposed mid-period review on DNO environmental performance and their progress to targets?

We agree, in principle, with the proposed mid-period review on DNO environmental performance and their progress to targets. We believe that high performing companies should report their performance externally every year and be held to account for their commitments regardless of the mid-period review and this is what UK Power Networks will continue to do.

Core-Q13. Do you agree with our consultation position for the DNOs' EAP proposals in RIIO-ED2 as set out in this document? (Further detail included in Appendix 1 of this document)

We agree with Ofgem's position for the DNOs' Environmental Action Plan (EAP) proposals in RIIO-ED2.

However, we have concerns about the way our proposals were assessed through the cost assessment exercise, on both Fluid Filled Cables and Fleet. In short, Ofgem has benchmarked costs based on historic costs and not taken into consideration the drivers for future costs. For example, we have made a commitment as part of our EAP to replace a significant portion of our operational fleet by 2028 to meet our Well Below 2°C (WB2D) decarbonisation commitment. Ofgem's proposed totex does not take into consideration the different level of capex required to transition to EVs. Therefore, the Draft Determinations in their current form will have a material impact on our commitments. The cost assessment methodology must be aligned with Ofgem's EAP guidance to ensure there is required funding available to deliver the commitments and targets made by DNOs. Please refer to our response to Core-Q93.

Core-Q14. Do you agree with our proposal to withdraw the Environmental Scorecard ODI-F for RIIO-ED2?

We accept Ofgem's position for RIIO-ED2, although we are disappointed in Ofgem's reversal from its Sector Specific Methodology Decision position on the introduction of an environmental scorecard with financial incentives. This decision seems counter-intuitive to the external environment and Ofgem's public commitments to deliver on the environment.

We continue to believe that high powered incentives encourage DNOs to improve their performance and environmental performance should not be an exception. We are conscious that it is now too late to develop this ODI-F for RIIO-ED2. We think it is important to work towards an environment scorecard underpinned by financial incentives for RIIO-ED3.

Core-Q15. Do you agree with our proposed approach to design of the Environmental Re-opener?

We agree with the scope and trigger window of the Environmental re-opener noting that these parameters are still under discussion in the RIIO-ED2 Working Groups.

However, we think that DNOs should have the ability to trigger the re-opener as well as Ofgem. As a minimum, Ofgem should provide greater clarity over the factors and circumstances which will warrant triggers. Assessing the impact of any legislative changes on DNO costs will require in-depth knowledge of the activities affected. It is highly likely that only the DNOs will be able to assess this impact to the required level of detail to determine if a re-opener will need to be triggered. By only having an Authority trigger, an additional, poorly, defined step of engagement will be required that could be better achieved through a formal submission from DNOs in a defined re-opener window.

Core-Q16. Do you agree with our proposal for addressing PCB contamination in PMTs through a volume driver in RIIO-ED2?

We support Ofgem's proposal for addressing polychlorinated biphenyl contamination ("PCB contamination") in both PMTs (via a volume driver) and GMTs (using baseline allowances). However, please note our views on Ofgem's cost assessment in our response to Core-Q90.

Supporting a smart, more flexible, digitally enabled energy system

Core-Q17. Do you agree with our proposal for implementing a Digitalisation Licence Obligation?

We are broadly supportive of the introduction of a digitalisation licence obligation. DNOs must be given a meaningful opportunity to input into updates to the Digitalisation Strategy Action Plan (DSAP) Guidance and Data Best Practice Guidance documents which were referred to in the draft licence obligation. The fact that these documents have been implemented in other sectors should not be used as justification for not updating them to the

specifics of the electricity distribution networks when Ofgem has been provided by DNOs which has not been given by those other sectors.

Core-Q18. Do you agree with our proposal to have staggered publications of Digitalisation Strategies between RIIO-ED2 and RIIO-2 licensees?

We do not see any immediate issues with the staggering of the publication dates of digitalisation strategies between RIIO-ED2 and RIIO-2 licensees, recognising that not all actions are fast moving and justify a six-monthly update.

We believe Ofgem should explore the merits of a lighter touch December update covering only material progress on relevant projects, with the June update being the full annual event. This will provide Ofgem and other stakeholders frequent updates but avoid unnecessary and burdensome reporting by licensees.

Core-Q19. Do you agree with our proposed Digitalisation re-opener?

We are supportive of the introduction of a digitalisation re-opener reflecting the fast-changing environment and uncertainties in this area. However, we have feedback on the proposed details of the implementation that would assist in making it fit for purpose:

- The single re-opener window at the end of the third year would be too late in the price control. In reality, it will only operate in time to adjust allowances for the final year of RIIO-ED2. We acknowledge that Ofgem can operate the re-opener at any point, however, this does not give the licensees control of the commencement of the process and therefore increases the risk DNOs are operating under and minimise underfunding and cash flow issues. We propose that two DNO-enacted windows, one of which should be at least one year earlier, would provide the best coverage; and
- As explained in our response to Q6, we disagree with the application of a 1% materiality threshold.

Core-Q20. Do you agree with the proposed enhanced reporting framework associated with IT/OT Data and Digitalisation spend and DSAP investment proposals?

Please see our response to Core-Q21 below.

Core-Q21. Do you agree with our proposal to adopt TBM as part of the RIGs/RRP?

We support the high-level implementation of a Technology Business Management (TBM) type taxonomy in the IT/OT Data and Digitalisation area. We are fully behind Ofgem's objective to achieve "*enhanced transparency, and increased comparability across DNOs' IT, OT, and Data and Digitalisation spend categories*"¹² which will drive further performance improvements in this area if it is designed, incentivised, and implemented properly.

However, there is a risk that TBM becomes a "cottage industry" - detailed levels of reporting (with additional overhead costs and bureaucracy) with little additional customer or business value. For example, taken to the extreme, if we had to assign IT service desk costs to fault activity, we would need to know each job the engineer was working on at the time they had an IT issue and rang the IT Service Desk. We struggle to see how this would help us be more efficient or deliver additional benefits to customers. In fact, it could result in greater inefficiency through burdensome reporting and consequent loss of productivity.

Our view is that TBM should be implemented robustly and with strong engagement between Ofgem and DNOs to ensure it delivers on the intended outcome. The implementation needs to consider how the reporting under TBM will fit into the overall RIGs reporting framework to avoid duplication and the level of detail that is appropriate under TBM to achieve the transparency and comparability in costs.

¹²RIIO-ED2 Draft Determinations, Core Methodology, paragraph 4.11

We are committed to providing resources from our business as part of a taskforce with Ofgem and other DNOs to design this change appropriately and implement it robustly. We encourage Ofgem to host a session to get this area moving in readiness for the start of RIIO-ED2.

Core-Q22. Do you agree with our intention to modernise the regulatory reporting process?

We are supportive of modernising the regulatory reporting process. However, from the detail provided in the consultation, it is not clear how this modernisation will take place and how it will interact with existing reporting processes. For example, there is a reference to the use of APIs and enhanced data services to streamline data submissions to Ofgem, but there is no worked example for us to understand how all the other vital elements of reporting (such as review and approval under the DAG) would be handled. We seek more information in these areas so that we are able to support Ofgem and be ready in time for future submissions.

Core-Q23. Do you agree with the proposed timeline for implementation of this modernisation?

We will only be able to give considered feedback on the timelines when more information is available in line with our response to Core-Q22. From the information available to us at this stage, we are concerned about the impact that a change mid-price control might mean to existing reporting. It would be helpful for Ofgem to confirm that if it implements a mid-price control, it would not be applied retrospectively and there would not be a need to resubmit data for earlier years in the new format. We look forward to working constructively with Ofgem to deliver on their ambitions in this area.

Core-Q24. Do you agree with our proposed design of the DSO incentive?

We think that Ofgem's Draft Determinations fail the stated objective to deliver Net Zero at the lowest cost to customers. Ofgem is insufficiently ambitious and fails to take into account interdependencies in four key areas: LRE assessment, load-related UMs, load normalisation and the DSO incentive. Aligning these four areas is key to ensuring that the regulatory framework contributes to delivering Net Zero at the lowest cost to customers. We present our views on the DSO incentive below.

We think Ofgem's proposed DSO incentive is significantly under-powered and will not drive the innovative behaviour required to meet the UK Government and Ofgem's objective to deliver a smart and flexible system. We discuss below the value of the incentive and the potential issue of relying on a qualitative assessment to measure performance.

1. The DSO incentive is under-powered and will not deliver for customers

The value of the DSO incentive, approximately £5.5 million per annum for UK Power Networks (i.e. 0.2% RoRE), is disconnected from the scale of the challenge for the industry and the benefits DSO functions will bring. Relying on a £5.5 million incentive to deliver between £780 million and £2.6 billion of benefits (NPV) is not proportionate¹³. It fails to recognise the scale of customer benefit at stake.

Establishing DSO functions will require a considerable change in culture and mindset from DNOs. DNOs will need, among other things, to learn to take a "flexibility and energy efficiency first" approach over capital-based solutions (i.e. reinforcement), harness data to better inform and target their investment decisions, and look beyond the electricity sector to inform business planning and investment decisions to achieve whole system outcomes.

Triggering this culture change and delivering real benefits to customers will require strong management and operational focus from the DNOs. UK Power Networks is wholly committed to this culture change and this is why we proposed the most ambitious DSO strategy, which demonstrably provides customer value by:

¹³ These savings have been independently validated by the ESO and The Carbon Trust.

- Deferring up to £410 million of reinforcement on our primary and secondary networks through the use of flexibility;
- Taking a “flexibility first” approach that will create a market opportunity that is over twice the amount of all of the other DNOs’ planned flexibility markets put together;
- Deferring £185 million of reinforcement that would have been required to connect distributed generation;
- Offsetting £747 million of baseline load-related investment that would have been required if we had used conventional forecasting methods instead of starting with the lowest cost path to Net Zero; and
- Saving c.£200 million at whole system level by undertaking Regional Development Programmes, increasing competition in national balancing markets, and avoiding the need for peak generation.

It is imperative that Ofgem increases the value of the DSO incentive to ensure that all DNOs are appropriately rewarded for delivering on the scale of the challenge. **We think that the DSO incentive should be on a par with the Interruption Incentive Scheme (IIS) incentive (at a minimum) or perhaps the most powerful incentive for RIIO-ED2, to reflect the critical role that DSOs will play in the transition to Net Zero strategic context. We recommend setting the reward value of the DSO incentive at 2% of RoRE.**

In support of this, we would make two further points:

- **First, we note that Ofgem introduced an asymmetric, positive, incentive for the ESO, valued at £30 million to -£12 million over two years.** In its RIIO2 Final Determinations for the ESO, Ofgem stated the rationale for the asymmetric ESO incentive *“recognises that the arrangements are relatively novel and there may be some uncertainty in how they are implemented. This will mean the ESO has more to potentially gain than potentially lose from stretching itself in more novel areas. We consider this is a beneficial incentive to create at this point in time when we need the ESO to be proactive and ambitious”*¹⁴. We believe the same arguments apply to the DSO and should be reflected in the DSO incentive to ensure it drives effective and ambitious DSO behaviour.
- **Second, we understand Ofgem’s desire to design an incentive package that provides sharp signals while protecting customers from higher than necessary costs.** We have conducted analysis to understand how likely DNOs are to hit the Return Adjustment Mechanism (RAM) threshold given different levels of totex outperformance and ODI outperformance. We analysed two scenarios:
 - A central scenario, where totex outperformance is based on average performance in RIIO-ED1 across all DNOs (using seven years of actuals) – which is unlikely in RIIO-ED2 given Ofgem’s introduction of UMs and tougher benchmarking, and ODI outperformance is based on UK Power Networks’ RIIO-ED1 performance as it is the leading industry performer; and
 - A high scenario, where totex outperformance is similarly based on average performance in RIIO-ED1 across all DNOs to date and ODI outperformance is set at 50% of maximum incentive revenue in RIIO-ED2 (based on the proposed incentive package in Ofgem’s Draft Determinations).

We found that in both scenarios, there is significant headroom to increase the value of the DSO incentive without risking DNOs reaching the RAM threshold. In a central scenario, there would still be at least 2% RoRE headroom available. Even in a high scenario, a DSO Incentive of 1.6% of RoRE would be possible without risking the RAM threshold being triggered.

Our analysis demonstrates that there is significant headroom to increase the maximum value of the DSO incentive to drive innovative behaviours while containing the overall cost to consumers within reasonable parameters. We hope that our analysis will provide a helpful framework for Ofgem to set the appropriate value of the DSO incentive.

Lastly, we would like to make a final suggestion. If Ofgem’s overall concern is that the potential upside rewards under the DSO incentive will be too substantial if assessed on an individual licensee basis, Ofgem

¹⁴ RIIO2 - Final Determinations, ESO Annex, paragraph 2.58

could opt to introduce a “zero sum incentive pot”. In this case, the DSO incentive would be worth a certain amount, for example £50 million. DNOs would be ranked based on the relevant DSO metrics. The first three DNOs - who have best performed - will be allocated £50 million (across the three DNOs). The last three DNOs, who have performed less well, will be penalised by an amount equal to £50 million (across the three DNOs). The individual reward and penalty amounts are calculated based on each DNO's performance, so that the total reward equals £50 million across the three best performing DNOs and the penalty equals £50 million across the three worst performing DNOs. Therefore, the final cost to customers will be zero, i.e. it is a zero sum. This could enable Ofgem to place a significantly higher upside reward for the DSO, without ultimately costing customers more money. However, such an approach would need careful assessment to ensure that costs to customers are distributed fairly across the country. Lastly, we appreciate our suggestion would make a change in policy at a late stage for RIIO-ED2. If this is the case, it is worth considering this for RIIO-ED3.

2. The DSO incentive places inappropriate reliance on qualitative assessment

We have compared the success of incentives used in RIIO-ED1 and we have found that incentives which rely on clear and robust performance metrics have led to significant performance improvements, whereas qualitative metrics deliver lower levels of performance. For example, as shown in the table below, incentives based on quantitative measures such as the Interruption Incentive Scheme (IIS) and Broad Measure of Customer Satisfaction (BMCS), have secured greater improvements for customers than incentives relying more on qualitative indicators, like the Stakeholder Engagement and Consumer Vulnerability (SECV) incentive. We believe that the explanation for this is the ambiguity of the qualitative metrics used in the SECV, which make it harder to determine what is needed to deliver a good outcome and to make investment decisions.

Table 3 - Comparison of average industry performance on IIS, BMCS and SECV in RIIO-ED1 (GB)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	% output improvement
CI	46	45	45	44	41	42	10%
CML	39	34	35	35.5	35	33	15%
BMCS	8.6	8.7	8.7	8.9	9	9.1	7%
SECV	7	6.7	6.8	6.4	5.6	5.5	-22%

Our analysis contrasts with Ofgem's current approach which proposes that the subjective views of the performance panel should amount to 40% of the assessment, with 20% coming from the objective outturn performance metrics and 40% for the subjective stakeholder survey.

Based on the evidence from RIIO-ED1, we believe that a greater emphasis on quantitative metrics for the DSO incentive will drive better outcomes for customers – especially given the scale of change needed with regards to DSO functions. The weighting of the outturn performance metrics should be increased relative to the performance panel. We propose the following revised weightings.

Table 4 - Proposed weightings for the DSO incentive

	Stakeholder survey	Performance Panel	KPIs
Ofgem proposed	40%	40%	20%
UKPN proposal	20%	20%	60%

Core-Q25. What are your views on the outturn performance metrics and RRE we are proposing to include in the DSO incentive? If you do not support their inclusion, please outline which alternative outturn performance metric(s) or RRE you think should be included in the framework instead.

Our response to this question is in three parts:

- In point 1 we set out our views on the three outturn performance metrics proposed in the Draft Determinations;
- In point 2 we propose converting two of the Regulatory Reported Evidence (RRE) – Transformer utilisation and Forecasting accuracy – into outturn performance metrics; and
- In point 3 we present our views on the remaining RRE.

Our views and suggestions are presented in further detail in our “DSO incentive metrics” supplementary document.

1. Our views on the proposed outturn performance metrics

Our views on the proposed outturn performance metrics are presented in the table below.

Table 5 - Our views on proposed outturn performance metrics for the DSO incentive

Proposed KPI	Our view
Curtailment efficiency	<p>We agree with the curtailment efficiency KPI. It will drive licensees to reduce curtailment, where it is economical to do so.</p> <p>We have identified two remaining issues:</p> <ul style="list-style-type: none"> • We should ensure the equation defined by Ofgem to estimate curtailment efficiency is workable with the available data; and • Further work is needed to define how to best manage existing non-firm connections.
Network visibility	<p>We support the inclusion of an outturn performance metric on network visibility.</p> <p>However, we think that Ofgem should incentivise DNOs to develop analytics-led approach in combination with traditional monitoring methods to improve visibility of LV networks at the lowest cost to customers. In its current form, this metric does not drive DSO behaviour but simply tracks the extent to which a DNO has delivered its monitoring programme (which can instead be achieved via a Price Control Deliverable). The DSO adds value by making use of analytics to get a more accurate view of network utilisation across all of its assets without having to deploy physical monitoring universally and regardless of cost.</p> <p>We recognise that analytical approaches will have a wider range of accuracy. We therefore recommend introducing a metric that measures the accuracy of LV network visibility attained through modelling, expressed as 1 – MAPE (the Mean Average Percentage Error). Alongside this, there should also be a higher weighting on sites where improved visibility delivers more value (e.g. where decisions to intervene will be made).</p> <p>To provide confidence around a licensee’s reported data accuracy, we request that Ofgem appoints an independent auditor to verify submitted data and to ensure that any modelling approach used is sufficiently robust. We believe this small additional cost is justified by the scale of investment at stake. There is also a precedent for doing this for the IIS mechanism, where auditing helped drive the accurate reporting of reliability.</p> <p>As our analysis in our response to Core-Q3 demonstrates that a further £300 million of secondary reinforcement allowances requested across DNOs’ business plans could be disallowed, chiefly because there is insufficient confidence around need. Accurate LV utilisation data will therefore be pivotal to increasing confidence around where, what and when network capacity is required across LV networks. This also aligns to the suite of</p>

Proposed KPI	Our view
	<p>metrics that Ofgem is setting to protect customers from over-investment through the secondary reinforcement volume driver.</p> <p>We have led by example as we have already established an independent audit process, led by GHD, for the LV utilisation data we submitted as part of our RIIO-ED2 Business Plan¹⁵.</p>
Flexibility market testing	<p>We do not agree with this metric in its current form. We have identified the following three key issues with this metric:</p> <ul style="list-style-type: none"> • First, the metric should be based on outcomes (i.e. amount of flexibility procured by DNOs), not intent (i.e. flexibility testing). Ofgem should merge this KPI with RRE1 (“Capacity released through flexibility”) to ensure that the volumes of flexibility procured are directly incentivised; • Second, there are interdependencies between this KPI and the secondary reinforcement volume driver which must be considered. If Ofgem wants to drive DSO related outcomes for the benefit of customers, flexibility procurement must not be excluded from the secondary reinforcement volume driver; and • Third, to increase transparency, secondary level flexibility should be separated out from flexibility procured at the primary level in terms of target setting. In its current form the combination of the two in one formula will cause issues due to the different network characteristics, as well as the different ways that utilisation, volumes and unit costs are calculated.

2. We propose converting two of the RRE – Transformer utilisation and Forecasting accuracy – into outturn performance metrics

In addition to the three outturn performance metrics, which we support with the appropriate enhancements, we suggest Transformer utilisation (RRE 4) and Forecasting accuracy (RRE 3) is converted into outturn performance metrics in their own right. These RRE are arguably the most important for driving the right DSO behaviours and can be easily measured using existing data collected and reported by DNOs. The inclusion of these as outturn performance metrics would reduce the administrative burden for the performance panel and ensure the remaining RRE are of similar importance, subject to the exclusions we note in part 3 of our response below.

We have developed a detailed methodology for each of these metrics using existing data that UK Power Networks reports to Ofgem and we have estimated performance using RIIO-ED1 data to demonstrate how they could be measured. We provide a summary of our proposed design of the metrics building on this, below:

1. **Transformer utilisation:** This metric is key to encouraging DNOs to resort to reinforcement only when necessary. There would be little – if any – additional data required to produce this metric because Ofgem is already using the utilisation metric as part of its capacity volume driver safeguards. Including this as an outturn performance metric would incentivise DNOs to produce accurate forecasts of network load and to deploy flexibility when the justification for reinforcement is not yet clear.
2. **Forecasting accuracy:** Accuracy of forecasts over time is a key DSO role. We would propose using Load Indices (LI) as the basis for this KPI, which would align with existing reporting processes, and would therefore require little additional administrative burden. LI outturn scores could be weighted by the number of risk points to reward forecasting accuracy at sites that have the highest levels of utilisation and the largest number of customers connected to them.

¹⁵ UK Power Networks’ RIIO-ED2 Business Plan, Appendix 21a

We have engaged with stakeholders, such as Citizens Advice and Octopus energy, who support the introduction of these metrics. Through email correspondence Octopus stated that they “*support the development of either a Utilisation Index as an outturn metric, or to use this to determine whether additional allowances can be allocated through the secondary volume driver, given the ability of this information to drive a culture change that focuses on using flexibility markets to manage uncertainties in demand levels where justified*”.

3. Other comments on the proposed list of RRE

In principle, Ofgem’s criteria for defining RRE and outturn metrics should be whether these metrics reveal what good performance looks like. As the experience with SECV has shown, it is essential that the metrics are well defined, and supported by a consistent and robust methodology. For example, Ofgem’s expert panel’s feedback on the SECV stressed the need for DNOs to “*work together to agree appropriate and consistent methods of assessing take up and benefits of general fuel poverty advice and of measuring the direct financial benefits to those customers receiving in-depth fuel poverty support*”¹⁶. We should therefore ensure that this feedback is effectively adopted for the DSO incentive and that we learn and improve from the RIIO-ED1 experience.

We believe the RRE should focus on a smaller set of metrics where there is genuine scope for identifying DSOs that are demonstrating exceptional performance. We would therefore recommend excluding the data publication (RRE 5) and operational data sharing (RRE 6) RRE. As currently designed, the RRE are likely to encourage box ticking as we cannot see how a Performance Panel would assess differences in quality or performance. As the real test of quality in this area will be in stakeholder use and accessibility this will be better captured as part of the survey element.

We would also recommend removing the flexibility procurement RRE (RRE 7). Our concern with this RRE is that it might discourage the use of tenders to test the market for the availability and price of flexibility. DSOs might prefer to limit tenders to those areas where flexibility markets are already well established as a result of the inclusion of this metric in the RRE.

We broadly agree with the intent and design of the remaining RRE but note that several of them will require careful interpretation within the assessment. In particular, while we understand the intent of the flexibility dispatch RRE (RRE 9), we are concerned it could skew the balance between availability and utilisation payments, and encourage inefficient dispatch. Similarly, for the flexibility tendering bid acceptance rate (RRE 8) we are unclear on why a high percentage of bid acceptances would necessarily be a positive outcome given it would imply low levels of liquidity.

More generally we welcome the opportunity to work with Ofgem to define the criteria for exceptional performance under each RRE to ensure they are appropriately interpreted as part of the panels assessment.

Core-Q26. Do you agree with our proposal for the DSO re-opener?

We are generally comfortable with Ofgem’s approach on the DSO re-opener. However, we want to stress the re-opener should not be used in a way that creates uncertainty which may undermine critical DSO investment. Ofgem should provide reassurances that, in line with the regulatory precedent, the re-opener will not lead to Ofgem clawing back investments which have been undertaken in good faith by the DNOs to implement their DSO strategy – without this reassurance it would risk deterring DSO investment.

We also seek clarification from Ofgem on the scope of the re-opener, particularly on the way that Ofgem will identify and allocate costs to DSO activities. This issue is exasperated by Ofgem’s benchmarking process that has allocated costs in a way that is inconsistent with reductions made in allowances. For Ofgem to effectively trigger a DSO re-opener and adjust future allowances, there needs to be a robust method in place that ensures costs are allocated to appropriate categories at a sufficiently granular level.

¹⁶ Challenge Group Panel Initial Feedback and Scores – SECV, 12 July 2022 Session

Core-Q27. Do you agree with our proposal to introduce a new whole system strategic planning Licence Obligation?

We fully support the introduction of a whole system strategy planning licence obligation.

In drafting the licence obligation, we believe the following aspects should be considered:

- The role of DNOs in local area energy planning, working in collaboration with local authorities;
- Encouraging the joint planning and coordination of networks across the energy system;
- Realising the benefits of full chain flexibility through enhanced price signals and reducing any conflicts between services;
- Developing digital tools that will enable stakeholders to layer local inputs such as decarbonisation action plans, local market trends and transport plans onto our network infrastructure data to accelerate their planning decisions¹⁷; and
- Opening-up data and encouraging market-led innovation, particularly with respect to LV networks as this is where the majority of activity is set to occur.

We also note that it will be important to develop interoperable standards and formats at pace. Once new company systems and data sets are introduced, it will be difficult and costly to migrate to new standards.

We would, however, request that Ofgem in its Final Determinations reconsiders the balance between incentives and obligations, which as currently constructed seems weighted firmly towards obligations:

- There are very weak DSO incentives and no further incentive on whole system planning; and
- While Ofgem calls out our whole system's strategy as being ambitious¹⁸, we cannot see how this is being rewarded through the current RIIO-ED2 package.

We think Ofgem should strengthen the incentives and mechanisms in place to encourage DNOs to take whole system initiatives. We recommend that:

- The DSO Incentive includes an element which is directly related to the delivery of whole system solutions. Ofgem's proposed DSO Performance Panel could take a role in assessing and ranking licensees' whole system annual reports. These annual reports would cover their performance against their whole system licence obligation as well as the extent to which licensees are delivering their business plan commitments;
- Ofgem enhances the Coordinated Adjustment Mechanism (CAM) as its use has been limited (if ever used). For example, there are instances where no licensee has allowances to deliver a whole system solution, in which cases the CAM is unapplicable. A process that links to a UM could provide additional funding if justified to DNOs, therefore allowing DNOs to use the CAM; and
- Ofgem should consider ways to encourage DNOs to deliver whole system initiatives which go beyond the electricity sector. For example, whole system solutions may require one party to forego revenue or incur cost in order for another party to secure an outcome which is overall in the collective interest. There are arrangements in place for these situations when both parties are within the electricity sector. Ofgem has yet to address how such projects are to be authorised where the extra cost or foregone revenue lies with the electricity sector, but the overall benefit lies with heat or transport, for example.

Core-Q28. What are your views on the digital tools that could be used to support this?

As part of our RIIO-ED2 stakeholder engagement, we heard that there are three key challenges that we can help to address, which are:

- Access to data, and how this translates into spatial planning requirements;

¹⁷ To support this UK Power Networks is leading project CLEO, which will provide a free online tool. More details can be found at: https://smarter.energynetworks.org/projects/nia_ukpn0079/

¹⁸ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 4.110

- A lack of expertise to turn ambition on decarbonisation into an action plan; and
- Access to funding resources to deliver an action plan.

In light of this, we have taken actions where we believe we are best placed to add value from a whole system's perspective. We have:

- Established a dedicated LAEP team that will ensure we can support all of the 116 local authorities we serve;
- Developed a free online energy planning tool to support stakeholders with their decision making; and
- Provided access to our datasets via an open data portal to encourage self-service and innovation.

We believe these actions bring value and should be mandatory requirements for all DNOs through their inclusion as whole system licence conditions. We would ask Ofgem to consider how these actions can be properly rewarded in the Final Determinations.

Meet the needs of consumers and network users

We are surprised and in disagreement with the number of steps Ofgem has taken to reduce the power of the incentive framework.

We particularly note:

- The introduction of an incentive package that is significantly more asymmetric (to the downside) than that of other energy utilities. Our analysis and views are detailed in our response to Core-Q46;
- The reduction of the IIS revenue cap by 60% without any supporting evidence to justify the decrease when compared with RII-ED1. We provide views on this in our response to Core-Q46;
- The introduction of deadbands. We disagree in principle with the introduction of deadbands which, by design, weaken the power of the incentive by applying it to a reduced range of performance. In addition, the use of deadbands interferes with the value of the incentive: the value of each percentage point within the performance band (the band outside of the deadband) becomes disproportionately large. Thus, deadbands dilute incentives immediately around the target level of performance, but potentially drive dysfunctional behaviour outside of the deadband limits. In this context, we also note that Ofwat has chosen not to use deadbands in PR24¹⁹; and
- The disproportionately small value of the DSO incentive. Our views are detailed in our response to Core-Q24.

We set our views below on specific incentives and their parameters.

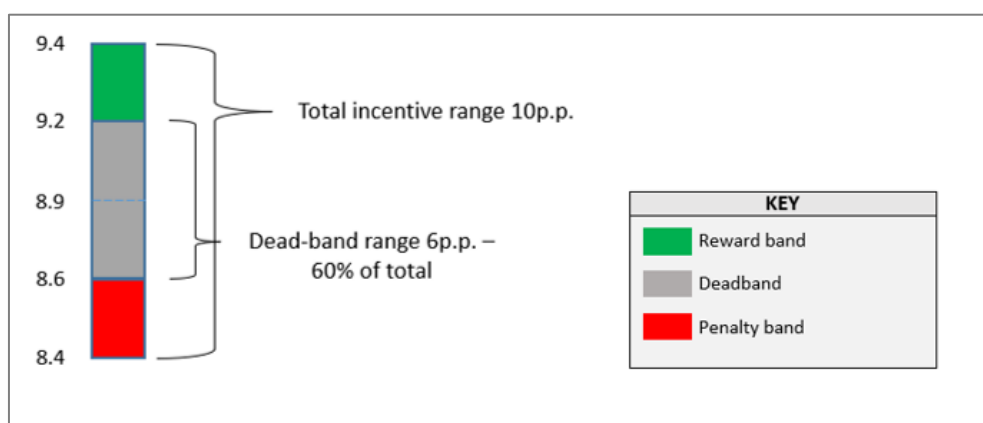
Core-Q29. Do you agree with our proposed target and thresholds for the deadband, maximum reward and penalty?

We agree with the proposed target and thresholds for the Customer Satisfaction Survey (CSS). However, we strongly disagree in principle with the application of deadbands. We are particularly concerned that, in addition to weakening the power of the incentive, it leads to unintended sensitive incentive bands.

As illustrated below, the use of a deadband means the effective incentivised range is incredibly small. Only two percentage points of measured customer satisfaction on the reward and penalty side respectively are subject to revenue adjustment.

¹⁹ Ofwat, PR24 Methodology Consultation, section 5.4.4

Figure 3 – Customer Satisfaction Survey incentive range including deadband



Deadbands lead to a very high effective incentive rate per percentage point of measured customer satisfaction, as shown in the table below. We do not believe there is evidence to support such a significant increase in incentive rate compared to RIIO-ED1.

We note that Ofgem introduced a deadband to ensure only companies that make significant improvements over current industry performance are rewarded. However, we believe this objective is outweighed by the downsides of deadband mechanisms. This risks leading to a lack of focus for companies who currently perform within the deadband, therefore stifling improvements for customers. For example, a company towards the bottom of the deadband (e.g. 8.7) halfway through a given year, has limited incentive to drive further performance improvements in that year as there is little chance they will achieve an annual score that will earn a reward – they would have to average 9.7 for the rest of the year to reach 9.2.

We request that Ofgem should remove the deadband in the Final Determinations so that a larger performance range is incentivised and subject to revenue adjustment. The impact of our proposal on the effective incentive rate per percentage point is shown below.

Table 6 - Comparison of effective incentive rate per percentage point of measured customer satisfaction

	RIIO-ED1 equivalent (reward)	RIIO-ED2 proposed	UKPN proposal*
Effective incentive rate per year per percentage point	£3.5m	£12.3m (250% increase)	£4.9m (40% increase)
Effective incentive rate RIIO-ED2 total per percentage point	£17.6m	£61.5m	£24.6m

*Based on removing the deadband.

Core-Q30. Do you agree with our proposed approach to working with DNOs to implement Storm Arwen actions related to customer satisfaction?

We agree that Ofgem and DNOs should work together to implement Storm Arwen actions related to customer satisfaction. We also believe, as Ofgem states²⁰, that they should not affect target, deadband or financial incentives of BMCS. However, we note that Ofgem's stated intention to review incentives in relation to call-backs is inconsistent with the principle of not affecting targets.²¹

Core-Q31. Do you agree with our proposed target and maximum penalty score?

We agree with the proposed target and maximum penalty score for the complaint metric.

Core-Q32. Do you agree with our proposal to remove the activities proposed from DNOs' baseline allowances?

We agree with Ofgem's proposals with the exception of energy efficiency. We outline our view with regards to energy efficiency in our response to UKPN-Q5 which refers to our Off-Gas CVP.

Core-Q33. Do you agree with our proposals for the Consumer Vulnerability ODI-F?

We broadly agree with Ofgem's proposals for the Consumer Vulnerability ODI-F. However, please note our views in our response to Core-Q34 below.

Core-Q34. Do you agree with the performance metrics we are proposing to include in the incentive and the approach to setting targets and associated deadbands, performance caps and penalty collars? If not, please explain why and give details of your preferred alternative.

We explain our views below on the parameters of the vulnerability incentive.

1. We disagree in principle with the use of deadbands

As discussed in our response to Core-Q29, we disagree with the application of deadbands. We request Ofgem to remove deadbands in its Final Determinations.

2. There should be a "truing-up" process in the year-5 assessment

We are supportive of the approach to assess delivery in years two and five of the RIIO-ED2 price control. However, we are concerned that Ofgem's decision to perform a staged assessment, where DNOs' performance at year-five would only consider performance from the beginning of year-three to the end of year-five²². This means that the reward or penalty a DNO receives at year-five does not reflect accurately its performance over the period, which can lead to perverse incentives. We summarise examples below to illustrate our analysis.

²⁰ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 5.23

²¹ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 5.24

²² RIIO-ED2 Draft Determinations, Core Methodology, paragraph 5.59

Table 7 - Examples of unwanted outcomes with the vulnerability incentive

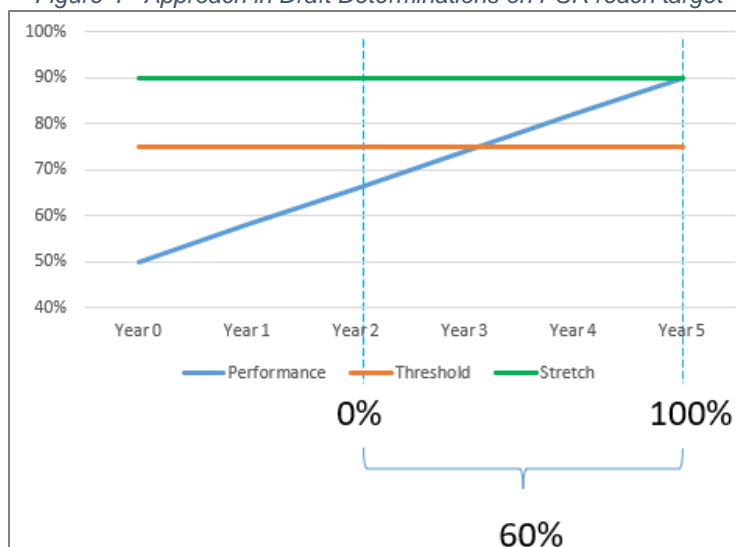
	Year 2 performance	Year 2 reward / penalty	Year 5 performance	Year 5 reward / penalty	Net position
Example 1	20% above baseline	+40% of revenue	Baseline performance only	0% of revenue for year 5	+40% of revenue for ultimately delivering baseline performance
Example 2	20% below baseline	-40% of revenue for year 2	Stretch performance	+60% of revenue	+20% of revenue for ultimately delivering stretch performance

We suggest that Ofgem adjusts the year-five assessment in the Final Determinations to better reflect the full-period outcome, for example with a truing-up process – recognising that there may need to be some recognition for timing of benefits delivered.

3. There should be a year-2 target for PSR reach

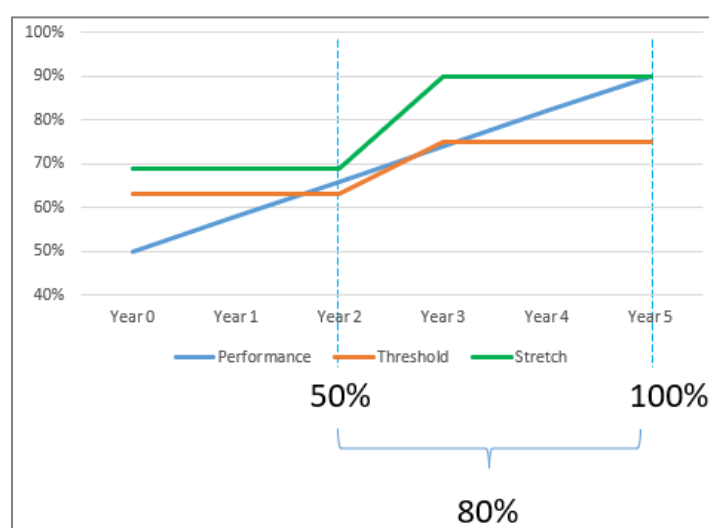
Currently, the PSR reach metric is cumulative over the five years of RIIO-ED2. By having no interim year-two target, DNOs will be held to account for delivering the full five-year performance in only the second year of the price control.

Figure 4 - Approach in Draft Determinations on PSR reach target



We propose that Ofgem introduces of a proportionate baseline and stretch target for the year-two assessment which represents a glidepath from a reasonable “year-zero” starting point to the end of period targets. This will put PSR reach on the same basis as the other cumulative targets (i.e. NPV targets). Our proposed approach which we are requesting Ofgem implements in the Final Determinations is illustrated below.

Figure 5 - Proposed approach for PSR reach target



Setting reasonable targets for year-two means the incentive will be operational for stretching but achievable performance therefore encouraging continuous improvement through the period.

4. The baseline CSAT targets are not reasonable

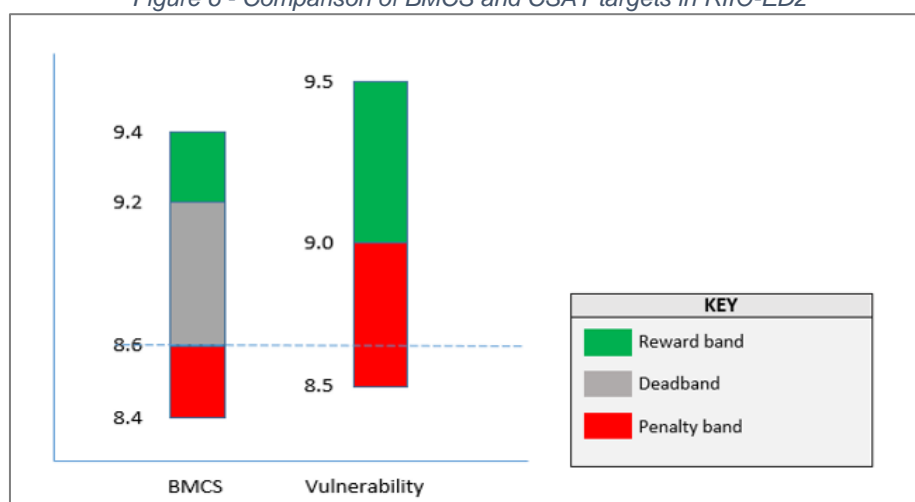
The consumer vulnerability incentive will be introduced for the first time in RIIO-ED2. It is normal regulatory practice for the targets that apply to new incentives to be set at levels that reflect their novelty. In part, this acknowledges the fact that companies will need time to organise themselves to meet the new standards of performance and is a well-established regulatory practice both for Ofgem and other economic regulators.

Indeed, this would be consistent with the approach that Ofgem proposes for the new connections incentive. In the case of the new Major Connections Customer Satisfaction Survey (CSAT), Ofgem has proposed a progressive approach, with a ramping-up of the target score.

In contrast, the targets proposed in the Draft Determinations for the vulnerability incentive are more challenging than the targets proposed for the BMCS. This is not proportionate, particularly given delivery will rely on partnerships with third party organisations.

The figure below shows that, in the extreme, a score of 8.6 would receive no penalty under proposed BMCS thresholds but would result in 80% of the penalty being applied for the CSAT element of the Vulnerability incentive.

Figure 6 - Comparison of BMCS and CSAT targets in RIIO-ED2



We suggest that in the Final Determinations Ofgem aligns the CSAT element of the vulnerability incentive with the BMCS target scores. We think that BMCS targets could be used as a proxy for the CSAT targets, given that there is no track record to use for CSAT targets. This would lead to stretching CSAT targets as they would be based on the targets of services which have been incentivised for over a decade, and for which DNOs have delivered significant performance improvements.

5. The targets need to be comparable

Ofgem has set bespoke targets for each DNO on the value of support services delivered in relation to fuel poverty and low carbon transition support. These targets are based on the Social Return on Investment (SROI) methodology and are summarised in the table below.

Table 8 - Comparison of targets for fuel poverty and low carbon transition support

	Fuel poverty support (NPV, £m)		Low carbon transition support (NPV, £m)	
	Year 2	Year 5	Year 2	Year 5
UKPN	3.71	9.28	1.06	6.39
ENWL	19.9	60.8	Not provided	Not provided
NPg	6.76	16.36	-0.66	-0.38
SPEN	3.19	9.66	0.4	3.61
SSEN	2.6	15.7	1.7	6.4
WPD	21.3	50.97	21.3	50.97

DNOs have used different approaches in their SROI modelling to estimate the value of their services. This does not impact financially on the design of the vulnerability incentive since Ofgem has set bespoke targets for each DNO. However, it does have a reputational impact for DNOs as customers may compare the targets to evaluate the DNOs' strategies.

We consider that the targets should be normalised so as to be comparable. We recommend normalising the targets based on our approach to SROI modelling which Ofgem recognised during working groups was the most robust approach used among the DNOs. This needs to be done between now and Final Determinations to ensure targets can be rebased in time to provide certainty for delivery. We would be happy to provide assistance in undertaking this task working in collaboration with other DNOs. We also note that in the recent Stakeholder and Consumer Vulnerability assessment year (2021/22), Ofgem's expert panel noted that this was an area that required a common approach to be applied across all DNOs. The Panel particularly urged DNOs to "work together to agree appropriate and consistent methods of assessing take up and benefits of general fuel poverty advice and of measuring the direct financial benefits to those customers receiving in depth fuel poverty support"²³.

²³ Panel Initial Feedback and Scores, SECV 12 July 2022 Session

Core-Q35. Do you agree with our proposal for the Annual Vulnerability Report ODI-R?

We agree with Ofgem's proposal for the Annual Vulnerability Report ODI-R.

Core-Q36. Do you agree with the proposed content of the annual report? If not, please explain why and give details of your preferred alternative.

We agree with the proposed content of the annual report noting that this is still under discussion in the RIIO-ED2 Working Groups.

Core-Q37. Do you agree with setting the maximum reward and penalty limit at +/-50% of the target?

We accept the proposed maximum reward and penalty. However, we note that this marks a step change from the RIIO-ED1 targets which were already set at +/-30% of the target. These levels of performance are increasingly difficult to achieve as DNOs face diminishing returns.

Core-Q38. Do you agree with setting a deadband of +/-20% of the target?

As explained in our response to Core-Q29, we disagree with the use of deadbands.

Core-Q39. Do you agree with our proposed design of the Major Connections incentive?

We agree with the proposed design of the Major Connections incentives. However, please note our views in our response to Core-Q40 below.

Core-Q40. Do you agree with our proposed approach to target setting and applying the penalty?

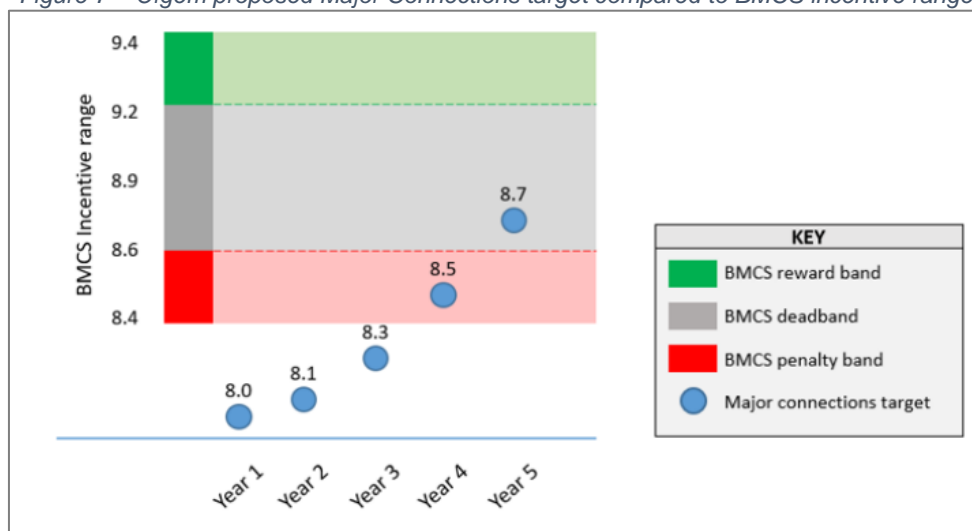
We agree with Ofgem's proposal to ramp up the targets, which recognises that the Major Connections incentive is a new mechanism. However, we disagree with the targets set by Ofgem. We explain our views below.

The targets set by Ofgem are not reasonable for the following reasons:

- Ofgem is proposing to adopt the customer satisfaction target scores proposed by DNOs in their major connections strategies. This is inappropriate because the targets proposed by DNOs were given on the basis of stretch performance – they should not be used as a baseline target;
- The targets for major connections, which is a new incentive, are more stretching than those of BMCS, which themselves represent sector-leading performance. The maximum penalty on major connections would be levied for a score that would be in the deadband under BMCS, and therefore receiving no penalty. This is illustrated in the figure below. We do not believe there is evidence to support setting connections targets which result in penalties that would not be penalised under more established mechanisms such as the BMCS;
- Indeed, the proposed targets would apply a penalty for scores that would be considered excellent customer service in any other sector. For example, the utilities sector's Customer Service Index is equivalent to 7.4/10 and the highest of any sector (retail non-food) is 8.2/10²⁴. Applying a full penalty in a penalty-only incentive for a score significantly higher than this is not reasonable; and
- Finally, the proposed approach breaks with normal practice for the targets that apply to new incentives to be set at levels that reflect their novelty. This normal practice acknowledges the fact that companies will need time to organise themselves to meet the new standards of performance.

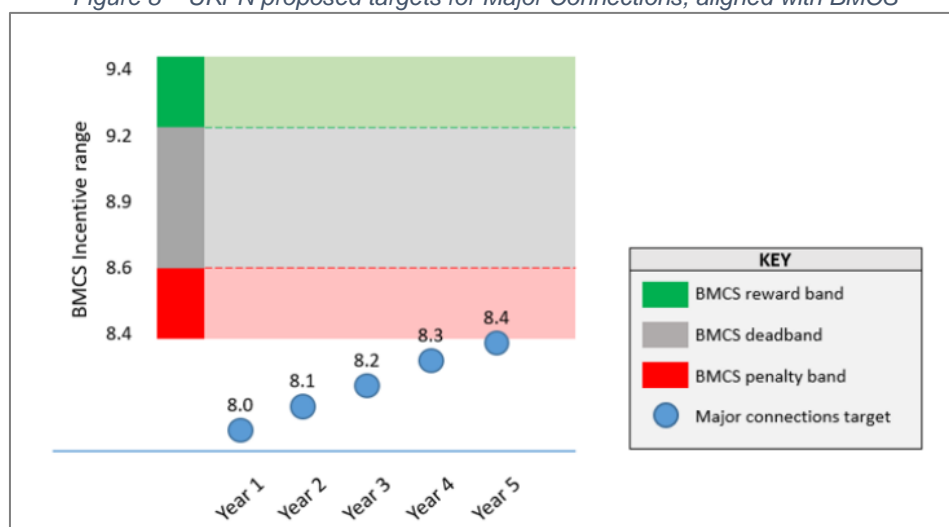
²⁴ The Institute of Consumer Service, July 2022, UK Customer Satisfaction Index

Figure 7 – Ofgem proposed Major Connections target compared to BMCS incentive range



We therefore propose that Ofgem should retain the ramping up of the target scores in the Final Determinations, while ensuring that the scores do not increase above the level that would attract full penalty under the BMCS. We propose alternative targets below, which use the BMCS track record to calibrate the point at which penalties should apply. We think that this approach leads to targets which are both realistic and stretching. Our proposal is illustrated in the figure below.

Figure 8 – UKPN proposed targets for Major Connections, aligned with BMCS



Core-Q41. Do you agree with our proposal to require reputational reporting of timeliness metrics for all RMS?

We agree with the proposal to require reputational reporting of timeliness metrics for all Relevant Market Segment (RMS). We want to stress that the information reported should be put within its context, for stakeholders to be able to interpret it. For example, we will work with our Connections customers to deliver their connection in line with their overall project timescales which can often be over several years. The reporting of timeliness metrics should not imply that shorter times are always expected or valued by customers; the goal is to meet the customer's expected timescales.

Core-Q42. Do you agree with our proposal to launch a wider review of the Connections GSoP (that is, beyond updating the payment amounts for inflation and incorporating standards for DG customers)?

We understand Ofgem's intention to undertake a wider review of the Connections Guaranteed Standards of Performance (GSoP). We note that, for this review to be successful, it needs to be planned properly with clear deliverables and milestones to allow both Ofgem and DNOs to prioritise resources appropriately.

Moving onto the scope of the proposed review, we have the following feedback which we would ask Ofgem to consider in reaching its Final Determinations:

- It is our recollection that the DG direction was introduced for legal reasons regarding the ability for Ofgem to introduce standards on non-demand customers. We recommend that Ofgem checks its archives for information on the decisions made at that time (for the start of DPCR5) to see if the same issues arise with their current proposal. For avoidance of doubt, we are comfortable that, if Ofgem can demonstrate that it has vires in this area, the GSoPs could be extended to include non-demand customers and the Distributed Generation direction could be removed; and
- We note that Ofgem believes that customers “*should be able to have a minimum standard they can expect from their DNO, yet note in a number of cases there is no standard for the overall (i.e. end to end) time to connect*”²⁵. We understand that Ofgem has made a proactive decision to not include all connections in the Time-To-Quote (TTQ) and Time-to-Connect (TTC) incentives and we seek clarity how the issues that were identified in the considerations for TTQ and TTC do not apply regarding a Connections GSoP.

Although there is no specific question in respect of non-connections Electricity Guaranteed Standards (EGS), we seek clarity from Ofgem in the Final Determinations on a date for the statutory instrument review and update. There are a number of elements which are to be reviewed (see below) and DNOs will be operating at risk in respect of the EGS until they have clarity on the scope and timeframes for this review. The elements under review are:

- The payment values for the first year of the standard;
- The method of updating for inflation (annual or set the first year as a mid-point of the length of the standard);
- Updated Severe Weather Exceptional Event (SWEE) thresholds; and
- The removal of the restriction which prevents payments by electronic means (e.g. bank transfer).

In the case of the SWEE thresholds, there is an interface with the RIIO-ED2 licence as the category one threshold is used as the SWEE exceptionality test. In the absence of the above being updated, DNOs will be following the requirements of the 2015 EGS statutory instrument and the current SWEE values would need to be rolled forward into the RIIO-ED2 licence.

Core-Q43. Do you have any views on what else could be done to help speed up connections to the distribution network and or develop a standard for the overall time to connect?

We welcome the further work Ofgem is taking on collecting information on all connections jobs quoted and delivered in RIIO-ED1 as part of its review into the potential introduction of an end-to-end time to connect standard or metric. We recognise that such a metric (or more likely suite of metrics reflecting the different voltages that customers connect to) could have benefits to stakeholders, even purely from a transparency perspective. The introduction of appropriately defined metrics will undoubtedly place a spotlight on performance, and as we have seen with other incentives introduced by Ofgem, should result in improvements for customers.

There is an inherent trade-off between maximising network capacity and investing ahead of need to ensure that customers do not face unnecessary delays to connect to the network. The design of an end-to-end time to connect standard should be cognizant of this trade-off to not drive perverse behaviours where, for example, DNOs would invest speculatively ahead of need. This issue is thus closely linked to the load-related UMs, which must be fit for purpose to enable DNOs to invest on the network when capacity needs are confirmed. We believe that further work

²⁵ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 5.184

is needed to make sure that Ofgem's proposed standard drives the right customer outcomes, i.e. appropriate connection lead times and low connections costs.

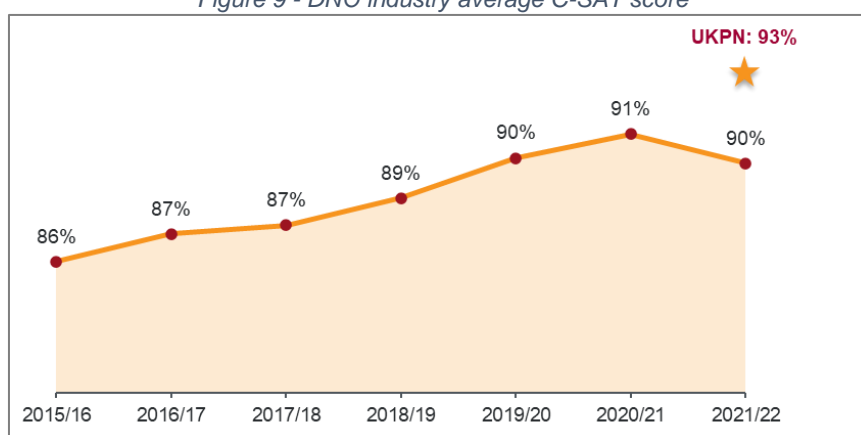
Core-Q44. Do you have evidence that customers would be willing to face an increase in their bills to also receive an increase in their reliability, including that they understand the actual cost and how this translates into average power cuts?

Ofgem's question strikes at the heart of whether an incentive for improving network reliability should remain in the RIIO-ED2 Final Determinations. Notwithstanding the difficulty in undertaking meaningful customer research in this area, Ofgem made it clear in its Sector Specific Methodology Decision that it would retain the IIS in RIIO-ED2. Therefore, we did not conduct customer research in this area as Ofgem had already set the parameters for RIIO-ED2.

What is undeniable is that as we electrify more of the economy, the reliability and resilience of the networks will become even more crucial. During Storm Arwen, it was made clear to DNOs by Ofgem that it is socially unacceptable for consumers to encounter a multi-day power cut.

By diluting the power of the IIS, Ofgem risks undermining the performance-based culture of DNOs to keep the lights on. RIIO has demonstrated that high powered incentives work and deliver value to customers. As Ofgem points out, electricity networks have achieved high performance, including on network reliability, which translates in high customer satisfaction.

Figure 9 - DNO industry average C-SAT score



Currently, water companies are being castigated by their customers for failing to get leakage under control and for failing to minimise pollution²⁶. In contrast, companies like UK Power Networks have delivered an 18% reduction in Customer Interruptions (CIs) and 23% reduction in Customer Minutes Lost (CMLs) over the last eight years.

Ofgem's proposal to reduce the power of the IIS could put at risk the current levels of performance achieved in the electricity sector. Ofgem should in particular consider in its Final Determinations the impact of its proposal on company culture. Ofgem's current proposal in the Draft Determinations would both remove the financial reward associated with good performance and send a signal that companies no longer need to improve. This could ultimately lead to a decline in performance and a subsequent difficulty to recover previous levels of performance due to a loss of skills and experience. It would then be costly to deliver high levels of performance, particularly considering that customers are increasingly dependent on electricity. We therefore consider that, in the long-term, Ofgem's proposal will not benefit customers and we would ask Ofgem to reconsider in its Final Determinations.

²⁶ Utility Week Article, 6th May, Ofwat Chief says companies still "failing to get the basics right".

Core-Q45. Do you have evidence of the cost of reliability improvements and the impact that lowering the revenue cap will have on them being achieved?

We are not able to answer this question for RIIO-ED2 as the level of the cap, the incentive rates and the targets are not yet confirmed. We reserve the right to comment further when these details are disclosed.

Maintain a safe, resilient and reliable network

Core-Q46. What are your views on moving to an asymmetric cap and collar?

We are disappointed in the late, unsignalled and unevidenced move to an asymmetric incentive. We note that:

- Ofgem had confirmed in the Sector Specific Methodology Decision that they would retain a symmetrical revenue cap for the IIS, set at 250 RoRE basis points;
- Ofgem appears to have chosen a 100bps cap without evidencing in the Draft Determinations how the number was arrived at. There is no evidence that the cap corresponds to the amount customers are willing to pay for further performance improvements;
- As shown in the table below, the RIIO-ED2 incentive package is more asymmetric than for other energy utilities. As the CMA noted in their redetermination of PR19, *“a package of asymmetric incentives should be considered as part of an in-the-round assessment of the package, including the cost of capital. If the package includes significant asymmetric incentives, such as large penalty-only incentives, then the expected return will be lower than the allowed cost of capital”*²⁷. In line with the CMA, we consider that the asymmetric package will increase the risk to our investors and has an impact on the WACC. Our views are detailed further in our responses to question FQ15; and

Table 9 - Comparison of incentives packages in RIIO-ED2 and GD&T2

	ED (proposed)	GD	ET	GT
RIIO-ED2 incentive package	- 4% / 1.95%	-0.7% / 0.3%	- 0.7% / 0.2%	-0.3% / +0.3%

- The reduced value of the IIS incentive now does not make sense in comparison with the value of BMCS, which has increased. This only makes sense if the fact that a power cut happens (which is incentivised through the IIS) is less important than what the customer says about it (which is incentivised through BMCS).

We dispute Ofgem’s justification for the introduction of the revenue cap. Ofgem states that *“the IIS is a significant source of potential outperformance and its size relative to other incentives could result in DNOs choosing to focus on reliability improvements at the expense of other customer benefits, such as totex efficiency and customer service”*²⁸:

- On the risk of excessive outperformance, it must be remembered that the total IIS revenue does not equal DNO’s outperformance, as a significant portion of it is used to fund improvements in performance and no additional funding is provided by customers;
- In addition, the RAM already ensures that DNOs do not make excessive returns. We do not understand why lowering the IIS revenue cap is also considered necessary; and
- We dispute Ofgem’s analysis that the focus on network reliability comes at the expense of totex efficiency and customer service. We have done all three²⁹.

²⁷ CMA redetermination of PR19, Final report, paragraph 9.1396

²⁸ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 6.31

²⁹ UK Power Networks’ analysis to support this claim is provided in Appendix 2 of our RIIO-ED2 Business Plan: Our RIIO-ED1 track record.

- o Ofgem recognised in its Draft Determinations that UK Power Networks is the most efficient DNO on average³⁰,
- o We have delivered industry-leading level of reliability during RIIO-ED1, which has seen an 18% improvement in our CIs and a 23% reduction in CMLs, and
- o Our Customer Satisfaction Survey scores continue to improve and exceed the targets we set ourselves for RIIO-ED1. We have achieved scores of 9.34, 9.22 and 9.21 in EPN, LPN and SPN respectively in 2020/21. We also occupy first place for BMCS compared to all DNOs for 2020/21 and achieved the Number 1 ranking in the prestigious Institute of Customer Service assessment in July 2022.

In summary, the asymmetric cap and collar appears arbitrary, irrational, and unjustified. We are concerned by the signal the asymmetric cap sends to DNOs and the incentives it may create. The reduction in the cap will effectively stop good performers from earning while the change of methodology to calculate CML will let off bad performers (we explain our views on the CML methodology in our response to Core-Q48 below).

Separately, we have concerns about the incentive rates. Having worked through the IIS incentive rate calculations, we can follow the logic of inflating the values from the 2008/9 Value of Lost Load. However, we do not follow the logic of using the total electricity consumed in GWh as a factor in calculating the “total amount customers are willing to pay for a year without electricity”. The focus on energy efficiency in the last decade has resulted in a drop of the amount of electricity consumed per customer by 17% since the start of DPCR5 (10% since the start of RIIO-ED1). This has been calculated using the data provided by Ofgem in response to the Supplementary Question on IIS incentive rates.

The effect of this declining consumption when used in the calculations is to infer that the loss of the same amount of electricity is worth less now than it was at the start of the previous price controls. This is clearly not the case:

- Our customer research indicates that customers consider it a priority to maintain high levels of network reliability;
- Recent storms have highlighted the importance of network reliability and resilience; and
- It does not make sense considering our increasing reliance on electricity (e.g. for homeworking, transport and heating).

To remedy this, Ofgem should, as a minimum, maintain the incentive rates at the same strength as in RIIO-ED1.

Core-Q47. Are there alternatives to reducing the revenue cap that you think would better balance increases in reliability and the cost to consumers than reducing the revenue cap?

We think one possibility Ofgem should explore in the Final Determinations is removing the application of the sharing factor from the IIS, which would bring it in alignment with BMCS. This would maintain the strength of the IIS and therefore the incentive for DNOs to make improvements, although DNOs would reach the revenue cap faster. It would also make Quality of Service (QoS) expenditure 100% DNO funded, putting the onus on DNOs to deliver and only be rewarded if customers benefit.

Core-Q48. Do you agree with how we have characterised the operation of the current CML methodology and our reasons for changing to setting targets in line with our CI methodology?

We agree that a ratchet would have added complexity and that using averages to set targets prevents abnormal years causing unwarranted up/downside. However, we think that the methodology is inappropriate for LPN, which has high performance compared to industry average. We consider the CI and

³⁰ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 7.8 t

CML targets to be unrealistic for LPN. We are also concerned that the new methodology results in giving a “free pass” to one DNO which badly performed in RIIO-ED1. We provide detailed views on these two points below.

1. The CI & CML methodology is not appropriate for LPN, given its high levels of performance

First, the CI & CML methodology has resulted in setting unrealistic targets for London. LPN is a very different network to all the other DNOs in that it has a far lower number of HV and above faults compared to the LV network. This makes it significantly more difficult to secure improvement in network reliability, for example because it is more costly and complex to automate the LV network.

The table below shows that almost 83% of CMLs on LPN’s network are on the LV network, compared to an average of 35% for other DNOs.

*Table 10 - Comparison of origins of CMLs**

CML	LPN No. of CMLs	%	Average of all other DNO's CMLs	%	LPN Difference from average
132	0.4	2.5%	0.2	0.7%	1.8%
EHV	0.2	1.6%	1.6	4.9%	3.3%
HV	1.9	13.3%	19.2	58.9%	45.6%
LV	12.1	82.6%	11.6	35.5%	47.2%
Total	14.7		32.6		

**The data uses 10-year average on 132 and EHV, and 4-year average on HV and LV.*

We make similar observations on CIs, where just over 54% of CIs happen on the LPN LV network compared to 16% on average for all other DNOs.

*Table 11 - Comparison of origins of CIs**

CI	LPN No. of CIs	%	Average of all other DNO's CIs	%	LPN Difference from average
132	1.37	10.00%	0.97	2.14%	7.86%
EHV	1.05	7.72%	5.02	11.10%	3.39%
HV	3.84	28.07%	31.99	70.74%	42.67%
LV	7.41	54.22%	7.24	16.01%	38.20%
Total	13.67		45.23		

**The data uses 10-year average on 132 and EHV, and 4-year average on HV and LV.*

We recommend that DNOs, such as LPN, which are significantly ahead of the benchmark, receive a target that is a blend of their own performance and the industry benchmark. This blend could be equal i.e. 50:50 or weighted e.g. 75:25 between own performance and the industry benchmark. The effect would be to dampen the “penalty” effect currently provided by Ofgem’s benchmarking approach, which penalises frontier DNOs, both in setting absolute targets that are tougher than those provided to DNOs that are poorer performers and in relative terms with respect to the improvements required in the RIIO-ED2 period to earn incentive rewards.

Our proposed methodology would give the following targets for LPN.

Table 12 - Revised CI and CML targets for LPN following our proposed methodology

		Weight	2023/24	2024/25	2025/26	2026/27	2027/28
CI	Benchmark	25%	21.4	21.3	21.2	21.1	21.0
	Average performance	75%	13.7	13.7	13.7	13.7	13.7
	Revised target		15.6	15.6	15.6	15.5	15.5
CML	Benchmark	25%	17.1	17.1	17.1	17.1	17.1
	Average performance	75%	14.7	14.7	14.7	14.7	14.7
	Revised target		15.3	15.3	15.3	15.3	15.3

Second, the annual improvement factor should be removed for LPN, in recognition of the high levels of performance it is already delivering. The figures below compare, separately for CIs and CMLs, how each network performs compared to the industry benchmark and what performance improvement it must achieve to earn full reward. It shows that, despite benchmarking best in the industry, LPN must achieve a significantly higher improvement in performance in CIs and CMLs to reach the maximum reward (shown on the vertical axis) from an already excellent baseline performance (shown in the horizontal axis). LPN is an outlier compared to other networks.

Figure 10 - Comparison of difference to benchmark and required improvement to earn full reward – CI

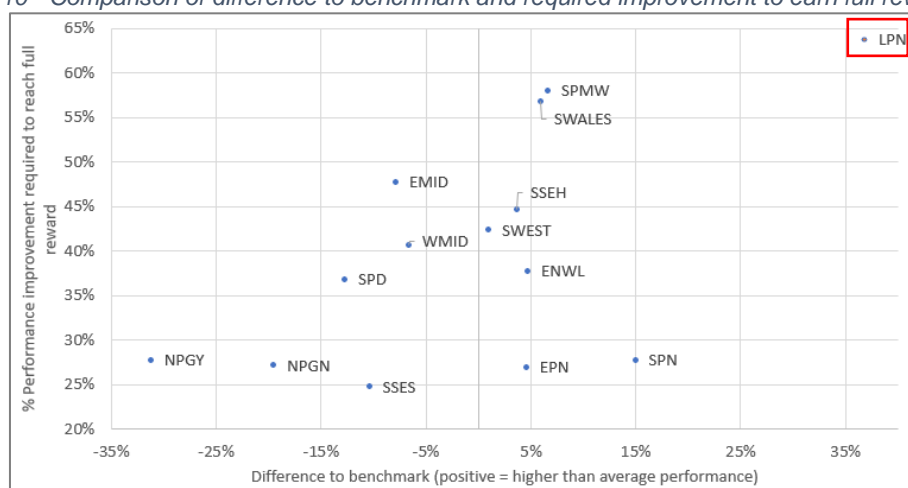
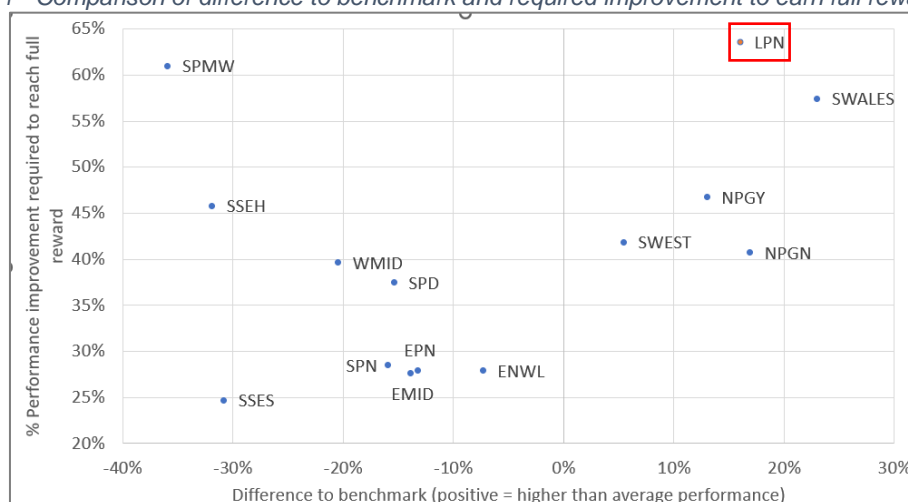


Figure 11 - Comparison of difference to benchmark and required improvement to earn full reward – CML



Furthermore, we note that the equivalent of the IIS for National Grid Electricity Transmission (NGET) - energy not supplied - is not set to incrementally tighten year on year. The incentivised Loss of Supply Events volume target is set at 147 MWh for the duration of the price control³¹. As the prospects for performance improvements become more remote on high performing networks like LPN, we consider that Ofgem should adopt a similar mechanism as it did in NGET's licence.

We therefore think that there is a strong rationale for removing the annual improvement factor for high performing DNOs. We request that Ofgem considers this in its Final Determinations.

2. The new CML methodology results in giving a “free pass” to a DNO which badly performed in RIIO-ED1

Ofgem recognises that “all but lower quartile DNOs would have less challenging targets at the start of RIIO-ED2 compared to the current CML methodology, with the most significant impact being in SSEN's region”³². We were surprised to discover that, as a result, SSEN's year one target for RIIO-ED2 is now easier than the year eight RIIO-ED1 target.

Table 13 - Comparison of RIIO-ED1 and RIIO-ED2 CML targets for SSEN

	RIIO-ED1 year 8 target	RIIO-ED2 year 1 target
SSEH	45.6	46.4
SSES	41.8	42.5

Ofgem also suggests that SSEN are “unlikely to be able to make significant further improvements”³³. We do not understand what evidence has been provided to Ofgem to support this. Experience from RIIO-ED1 has shown that an appropriate management focus and investment in capabilities such as automation allows DNOs to deliver improvement in performance. Organisations which have failed to improve their performance in RIIO-ED1 should not be rewarded with softer targets in RIIO-ED2.

To remedy this, we think that Ofgem should set the CML targets based on the lower target suggested by either the RIIO-ED1 methodology or the proposed RIIO-ED2 methodology.

³¹ NGET's licence, paragraph 2.4

³² RIIO-ED2 Draft Determinations, Core Methodology, paragraph 6.57

³³ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 6.56

Core-Q49. Do you agree with our rationale for retaining our RIIO-ED1 position on QoS funding? Can you provide any evidence that an alternative approach would not result in double rewarding alongside the IIS?

We are supportive of Ofgem’s rationale for retaining the RIIO-ED1 position on QoS funding.

This ensures a level playing field for all licensees and avoids any double reward for licensees. We agree that funding reliability-related improvements such as HV automation would then allow DNOs to earn rewards under the IIS, therefore double funding the improvements. We also note a parallel with our situation in RIIO-ED1 where Ofgem approved the funding of a central London depot but applied tougher IIS targets for LPN to avoid double reward. We think that this should be replicated where DNOs get ex-ante funding for reliability-related improvements.

Ofgem also notes that “*at least one DNO has argued that they need QoS funding in order to avoid starting RIIO-ED2 in a penalty position for CMLs*”³⁴. Granting funding on this ground would amount to rewarding bad performance. In addition, other DNOs have shown that with management focus and appropriate investment through RIIO-ED1, good CML performance can be achieved, and funded and rewarded through the IIS.

Core-Q50. Do you have any examples of situations where fault-related interruptions could be genuinely “exceptional” and how these could be separately identified from those that occur during planned works?

We support the removal of weather-related claims under the Other Exception Events (OEE) mechanism, as any qualifying events should be exempted using the SWEE mechanism

We disagree with Ofgem’s decisions to remove of the possibility to raise claims for incidents that occur during the normal operation of the network. This is explained in more detail below.

Ofgem’s proposal contradicts the original purpose of the OEE mechanism. Indeed, footer 12 of the 2004 Distribution Price Control Review – Final Proposals on OEE specifies that “*where planned work is being carried out on a circuit and there are appropriate levels of contingency in place to ensure security of supply in line with the principles of Engineering Recommendation P2/5, additional incidents outside the DNO’s control which are caused by a third-party, act of God or which are outside the DNO’s normal experience, which cause interruptions to supply would be considered under the exceptionality scheme if they breach the relevant thresholds*”. We do not understand why Ofgem has changed its mind on the scope of the OEE mechanism nor does Ofgem appear to have set out the evidence on which it has based its decision to change the scope.

Requiring DNOs to face the impact of incidents during planned operation and maintenance will create an incentive to build networks with a greater degree of redundancy, which will be very costly for consumers. If Ofgem were to confirm this proposal in the Final Determinations, it should first conduct a robust cost-benefit analysis to understand the costs associated with its proposal and justify its approach.

In addition, Ofgem’s proposal may reduce the incentive power of the IIS and contradict its original purpose, which is to incentivise *underlying* performance. Incidents during planned operation and maintenance can have a very significant impact on CMLs, wiping out all the performance secured during the price control. In effect, a DNO could lose the reward earned from good performance due to a single high-impact event that is beyond its control. The IIS would arguably become a lottery on exceptional events and undermine the regulatory principle of proportionality.

Nonetheless, we agree that customers should not bear the normal risks of network operation and maintenance. We think that a more appropriate solution may be in respect of defining whether the fault falls within DNOs’ control. For example, DNOs could be required to prove that the fault was beyond their control and/or they could not have taken action to prevent or react to the issue in line with the mechanisms already in place for RIIO-ED1.

With the above in mind, we do not believe that Ofgem was correct to add back in to the target setting data the CI and CML performance for the six events in DPCR5/RIIO-ED1 (see UKPN SQ-03).

³⁴ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 6.69

Core-Q51. Do you agree with our assessment of the OEE thresholds and the financial impact on each DNO?

Based on Ofgem's answer to our Supplementary Question on this, we are happy with the proposed approach.

Core-Q52. Do you agree with our proposal not to have an end-of-period adjustment mechanism? If not, what criteria should we use to determine whether a DNO has used its allowance for WSC, without it creating uncertainty?

We are supportive of the changes made by Ofgem to improve and implement a Worst Served Customers (WSC) mechanism for RIIO-ED2. We agree with the proposal to not have an end-of-period adjustment mechanism for WSC as the justification for its need is negated by:

- the Use-It-Or-Lose-It (UIOLI) mechanism which manages the return of unspent allowances; and
- the use of the governance document and ongoing reporting of WSC spend/schemes to ensure expenditure is in line with the scope of WSC definitions.

Core-Q53. Are there any other areas or metrics that we should include in our governance framework?

Mindful of the urgency of developing the governance framework, we were pleased to see that Ofgem facilitated a Safety, Resilience and Reliability Working Group (SRRWG) meeting on 28 July to progress its development.

One of the key elements of the reporting is proportionality to ensure Ofgem is provided with the required information without this resulting in a burden for DNOs where manual reporting is required. Using the RIIO-ED1 reporting as a basis and adding/removing data from it is a sensible position.

Core-Q54. Do you agree with our proposed approach on NARM?

We agree with some elements of Ofgem's approach to Network Asset Risk Metric (NARM), including:

- To retain requirements on the DNOs to produce an Information Gathering Plan which sets out how they will gather and record the information required to implement the Common Network Asset Indices Methodology (CNAIM);
- Not to introduce a UM for non-NARM-related expenditure; and
- To set the deadband around the NARM output at +/-5% and to retain the RIIO-ED1 penalty rate at 2.5% of avoided costs associated with unjustified under-delivery against the NARM output.

Please note, there is an error presented in "Table 20 Summary of Risk Movements (£R, 2020/21 prices)" of the Core Methodology document. The risk movements for EPN and SPN are the wrong way around and this should be corrected.

However, we strongly disagree with Ofgem's proposal in its Draft Determinations to set the NARM output in line with the DNO's submitted views of the monetised risk reduction they expect to deliver. We detail our views below.

1. The volume cuts are so drastic that we will be unable to deliver our target

The reasoning Ofgem uses to justify its position on holding NARMs targets as submitted by the DNOs is the observed performance of all companies in RIIO-ED1, where licensees are on track to deliver their targets, but via fewer volumes of interventions.

UK Power Networks' strategy is to continually assess the most cost-effective way of delivering its target whilst providing great service to our customers. This means the mix of assets that we focus our interventions on, and the type of intervention used, are continually evolving to deliver this strategy in the most optimum way. This approach allows us to deliver our outputs at the lowest cost while maintaining industry leading performance.

However, the cuts that Ofgem has made to allowed volumes in the Draft Determinations are so drastic (circa 59% cut to all NARM-related expenditure at disaggregated level) that even with our current strategy, it would not be possible to deliver our Business Plan target in RIIO-ED2. The cuts to the volumes and hence the associated allowance means there are no realistic or credible combinations of intervention changes, either asset or type. This needs to be reconsidered urgently and addressed in the Final Determinations.

2. Network risk will rise to unacceptable levels

To help demonstrate the severity of the cuts that have been made to our NARMs volumes, we have remodelled what the effect on network risk would be:

Table 14 - Overall risk position (end of RIIO-ED2)

DNO	BPDT Submitted Volumes	Ofgem DD Allowed Volumes	Change
EPN	4.6%	16.6%	+12.0%
LPN	8.2%	14.9%	+6.7%
SPN	2.6%	12.9%	+10.3%
UKPN	4.7%	15.1%	+10.5%

This outcome would be untenable on a number of levels:

- Allowing network risk to rise to this level will result in asset failures and lower reliability in future. This is particularly unpalatable given the push for electrification as part of the Net Zero agenda;
- Part of the reasoning for our submission to contain an uplift in interventions was to produce a deliverable plan over RIIO-ED2 that supports an overall long-term asset strategy. Our expectation is that the volumes of work will continue to rise across both RIIO-ED3 and RIIO-ED4 to address the profile of aging assets. We chose to phase the work in RIIO-ED2 to ensure we can scale up delivery capabilities cost effectively and maintain flexibility to adapt to any scenario. Cutting volumes so drastically in RIIO-ED2 will result in a tidal wave of intervention activity in RIIO-ED3 and beyond, one that would result in serious deliverability concerns and ineffective expenditure; and
- It goes counter to our customers' expectations. Throughout our RIIO-ED2 customer engagement programme, our customers repeatedly told us that they expected a reliable supply as a base requirement, and that network performance should at the very least be maintained at current levels.

3. The perceived disproportionate benefit from refurbishment activities in RIIO-ED1 has been reduced in RIIO-ED2, and thus is not a valid argument.

We understand that Ofgem wants to avoid DNOs being biased towards lower cost refurbishment options even when replacement may be a more appropriate course of action. However, the recent change in the CNAIM methodology now means that all risk movements are calculated on a whole life basis, as opposed to a snapshot in time. This change in methodology more accurately reflects the benefits associated with refurbishment and replacement work and as result any bias towards refurbishment work is removed. We believe that the revised CNAIM methodology, which was approved by Ofgem in April 2021, should be sufficient to alleviate Ofgem's concerns.

4. Ofgem's position effectively removes DNOs' flexibility to manage assets appropriately

Ofgem reiterates that they believe the NARM framework provides the flexibility to manage assets appropriately and deliver the outputs. However, whilst the framework does indeed give this flexibility, Ofgem's policy intent takes that away. It is in effect hardwiring a bias into the regulatory framework, forcing network companies to take investment

decisions that are not in the interests of the network or customers purely to try and deliver an undeliverable target. It will force DNOs to target assets that will give more points, and leaving assets that deliver less points to deteriorate and still needing replacement. It does the opposite to allowing DNOs to manage risk appropriately.

This intent would also expose us to the risk of a financial penalty as defined in the licence at the end of the price control even in a situation where we deliver 100% of the 'approved' interventions by Ofgem themselves. This is not a tenable situation and should be appropriately addressed in the Final Determinations.

We understand Ofgem's concern about DNOs not receiving allowances for work not undertaken, while enabling DNOs sufficient flexibility to adapt their asset strategies to deliver at the lowest cost for customers. Therefore, we have made a suggestion to adapt the NARM framework taking this trade-off into consideration.

As communicated to Ofgem, there are solutions that could be incorporated into the existing NARM framework. These proposals would still maintain a degree of flexibility in risk-trading between asset categories, while limiting the magnitude of the variance between submitted and delivered intervention volumes seen in RIIO-ED1.

For example, whilst an overall 'network level target' for risk could be set with a +/-5% deadband, sub-targets could be introduced at the different voltage levels with a wider deadband, to facilitate flexibility in delivery. This would have two benefits:

- It would allow DNOs to respond to emerging priorities as and when new asset data emerges that results in a change in intervention mix from that submitted in original plans; and
- The sub-level 'voltage targets' would provide Ofgem with more confidence that delivery will be more in line with that submitted and negate the need for Ofgem to set a target that is not associated with the volume of allowances allowed.

The table below summarises how we propose variances would be dealt. In essence, exposure to the 2.5% penalty would only be applied in case of unjustified under-delivery of the 'network level target'. Variances in voltage level targets would not be subject to a financial penalty.

Table 15 - Practical examples of our proposed NARM framework

Example	Description	Treatment
1	Variance on 'network level target' beyond deadbands (either under or over). <u>Note:</u> any variance on voltage level targets is irrelevant in this assessment as all adjustments will be made based on delivery against the network target.	Treated as already defined by Ofgem within the existing NARM incentive framework.
2	On target for 'network level target', but under delivery of one or more 'voltage level targets'.	A downward allowance adjustment based on the £/point at that voltage level.
3	On target for 'network level target', but over-delivery of one or more 'voltage level targets'.	If over-delivery deemed unjustified, no adjustment. If over-delivery deemed justified, upward allowance adjustment based on the £/point at that voltage level
4	On target for 'network level target' but a combination of over and under delivery of 'voltage targets'.	Upward and downward allowance adjustments in line with the treatments explained in examples two and three above.

We welcome the opportunity to discuss this proposal further with Ofgem and other DNOs.

Core-Q55. Do you agree with our proposal to pass through SW 1-in-20 costs as a variant totex allowance rather than a fixed allowance in RIIO-ED2?

We are comfortable with Ofgem's position. Our working through the SRRWG, and particularly a meeting on 28 July has helpfully clarified the scope of the pass through.

Core-Q56. Do you agree with our proposal to not set a cap for the amount that DNOs can adjust their allowance by, in the event they experience a SW 1-in-20 storm?

We agree that Ofgem should not set a cap on the amount that DNOs can adjust their allowances by if they experience a 1-in-20 severe weather event. The ever-increasing expectations of DNOs from Ofgem and customers in storms (be it in terms of generator provision, subsistence, and payments for expenses (paying for hotel or food for customers who are out of power), extra staffing) means 1-in-20 costs are likely to increase per customer and therefore having a cap is counterproductive.

Core-Q57. Do you agree with our proposed approach to the physical site security re-opener?

At a high level we agree with the proposed scope, trigger, re-opener window and materiality threshold for the physical site security re-opener.

However, in light of recent dialogue with the UK Government, we think that the re-opener should be crafted such that it is capable of managing the changes to the scope of Critical National Infrastructure (CNI) sites – be that the addition of new sites or the inclusion of non-physical sites (e.g. “systems”). We are happy to work with Ofgem and the UK Government to ensure this scope is correctly drafted.

Core-Q58. Do you agree with our proposed approach to the ESR re-opener?

We agree with the proposed scope and materiality threshold for the Electricity System Restoration (ESR) re-opener.

However, we believe there is opportunity for Ofgem to simplify the trigger and re-opener window. The DNO triggered window of 24– 28 June appears arbitrary. This DNO triggered options run the risk of being either not utilised (if new requirements are yet to be established) or could result in a rushed or poorly evidenced application (should any new requirements be issued near the re-opener deadline). Furthermore, as seen recently through unexpected issues such as the SOLR process and Storm Arwen, other priorities could emerge that detract from any application.

Instead, given the ability for Ofgem to trigger the re-opener at any time, we suggest Ofgem could simplify such that the trigger is by Ofgem only, and that it can be issued at any time. This can be then activated as and when new requirements emerge, are well defined and takes due consideration of the circumstances at the time such to allow DNOs the appropriate time to apply with fully costed and evidenced proposals.

Core-Q59. Do you agree with our approach to fund DNO telecoms resilience activities through baseline allowances?

Telecom resilience activities are a sub-set of ESR. Please refer to our response to Core-Q82. We consider that no ex-ante funding should be provided until the new Government ESR requirements are published.

Core-Q60. Do you agree with our proposal to assess the cyber resilience IT and OT plans against our BPG and RIIO-2 re-opener guidance?

Please see our confidential response to the cyber elements of the Draft Determinations for the details of why we do not support the proposals.

Core-Q61. Do you agree with our proposed re-opener windows for cyber resilience OT and IT?

Please see our confidential response to the cyber elements of the Draft Determinations consultation for the details of why we do not support the proposals.

Core-Q62. Do you agree with our proposal to apply a UIOLI allowance to cyber resilience OT to manage the uncertainty around costs?

Please see our confidential response to the cyber elements of the Draft Determinations consultation for the details of why we do not support the proposals.

Delivering at lowest cost to energy consumers

Core-Q63. Do you agree with our proposed approach to pre-modelling normalisations and adjustments?

We are concerned at the way that, for the other DNOs, Ofgem has moved the costs associated with UMs into their ex-ante allowance. We are not satisfied that this approach has resulted in a fair outcome. To ensure that customers do not pay for unnecessary investment, we proposed low ex-ante costs and the extensive use of UMs to adjust for demand. It would be fundamentally unjust if our ambitious approach resulted in a lower allowance than we would have received had we been less ambitious and included more funding in our ex-ante allowances. We are concerned that Ofgem has adjusted upwards the ex-ante allowance of other DNOs but has not made equivalent adjustments to UK Power Networks' allowance. This is discriminatory, irrational and unfair.

Please see NERA's report "Review of RIIO-ED2 Draft Determinations" (thereafter "NERA document") section 3.3 for supporting evidence of our position.

We agree with Ofgem's proposals that the pre-modelling adjustments should include the removal of passthrough costs, including "Severe Weather 1 in 20" costs. It will be important to have robust and detailed guidance on the allocation of costs to ensure that this policy change is implemented correctly.

We also agree with Ofgem's decision to remove costs that other DNOs proposed would be used to improve quality of service. Ofgem's proposed approach is aligned with our thinking - UK Power Networks did not submit quality of service costs, reflecting the fact that improvements in quality of service are funded through incentivised reliability incentives.

Core-Q64. Do you agree with our approach to totex benchmarking?

We disagree with Ofgem's approach to totex benchmarking. Please see attached NERA assessment of the benchmarking, section 3 and Melvyn Weeks' report on "Evaluating Ofgem's comparative assessment of RIIO-ED2 business plans"³⁵.

Core-Q65. Do you agree with our proposed assessment approach for primary reinforcement?

We broadly agree with Ofgem's approach to setting baseline primary reinforcement costs and volumes.

As noted in our response to Core-Q5, our view is that the LRE re-opener window needs to be brought forward to year-two of RIIO-ED2 (2024). This will enable DNOs to justify additional allowances in circumstances where demand is higher than what was inferred in baseline allowances. It will also provide important protection if Access SCR rule changes lead to increased new connection requests and/or customers with non-firm access requests.

We note the Engineering Hub's assessment of our load Engineering Justification Papers (EJPs), and have provided a supplementary response to these queries via our additional "Load Engineering Response" supplementary document.

³⁵ Melvyn Weeks, 25 August 2022, Evaluating Ofgem's comparative assessment of RIIO-ED2 business plans", Prepared for UK Power Networks

Furthermore, we have highlighted to Ofgem in recent bilateral meetings potential additional ex-ante allowance required to resolve constraints in West London. We have submitted an additional EJP alongside this response, “ED2-EJP-LP-101, West London Growth”, that outlines our proposal. We remain available for further dialogue as appropriate once Ofgem has reviewed.

Core-Q66. Do you agree with the application of a volume adjustment based on the industry average ratio of forecast capacity added relative to the forecast demand growth above firm capacity? If not, what do you consider to be a better approach to assessing the efficiency of a DNO’s proposed workload for primary network reinforcement?

We agree with this approach. It is important that Ofgem factors in demand growth above firm capacity and reflects the current utilisation level of primary level substations as these will be key drivers to LRE requirements

Core-Q67. Do you agree with our proposed assessment approach for secondary reinforcement?

Broadly, we are supportive of the proposed volume driver mechanism for secondary reinforcement. However, we believe that Ofgem needs to address the following substantial issues in the Final Determinations:

- The inclusion of flexibility in the volume driver mechanism in order to avoid a capex bias;
- Setting appropriate unit costs for cable reinforcement reflective of the overhead / underground mix within the respective DNOs, noting that this is a particular issue for LPN which almost exclusively uses underground cable. LPN is materially disadvantaged and discriminated against by Ofgem adopting the current approach;
- The capitalisation rates should be identical for ex-ante and ex-post funding. DNOs that have followed Ofgem’s guidance with realistic ex-ante totex forecasts should not be penalised with a different capitalisation rate; and
- Setting appropriate unit cost allowances for the LV services volume driver.

Please refer to our answer to Core-Q4 for further detail.

Related to the ex-ante assessment is the need for the volume driver to incorporate an element of funding for indirects. Please see NERA report section 9 which sets out clear evidence of the relationship of direct and indirects.

Core-Q68. Do you agree with the level of disaggregation and period of data used to calculate the unit costs listed in the table above for transformer reinforcement, circuit reinforcement and proactive service reinforcement?

We do not agree with the way that Ofgem has calculated CV2 (secondary reinforcement costs) and would request that this is addressed in the Final Determinations. There is a significant difference between overhead and underground costs, which Ofgem’s approach does not reflect. This is clearly evident in the asset replacement analysis undertaken by Ofgem, where the median RIIO-ED2 unit cost for LV overhead line work is £21.9k per km, whilst the LV underground main (plastic) unit cost is £107.9k per km, which is a material differentiation in cost. Similarly, at HV, the respective RIIO-ED2 median unit costs for 6.6/11kV overhead lines and underground circuits are £25.4k per km and £119.8k per km. However, Ofgem has not sought to disaggregate the two costs in its unit cost analysis for secondary reinforcement. This has led to manifest errors in the appropriate allowances, which are particularly pronounced in the case of London (which has almost no overhead cables).

We believe that Ofgem already has the necessary disaggregated LV and HV overhead and underground circuit data from the responses to a Supplementary Question (UKPN016) it asked all DNOs (to be able to undertake its unit cost analysis at the appropriate level of disaggregation).

Since the publication of the Draft Determinations, Ofgem has requested further information from the DNOs on the cost of fuse upgrades. We understand Ofgem plans to strip these costs out of benchmarking. We support this

approach. We consider there needs to be consistent treatment of this activity for all DNOs, with all service reinforcement costs moving to CV2 as commented by Ofgem in paragraph 7.193 of the Core Methodology document. If Ofgem were to adopt a different approach, we would be grateful for early sight of the analysis, to allow us the opportunity to verify the calculations.

Core-Q69. Do you agree with our proposed assessment approach for fault level reinforcement?

Yes, we agree with Ofgem's assessment approach to fault level reinforcement.

Core-Q70. Do you agree with our proposed adjustments to account for outlier volumes data for ENWL and SSES?

We do not agree with Ofgem's proposed adjustment and would ask Ofgem to reconsider this in the Final Determinations.

We are unsure why ENWL has this bespoke adjustment given their own interpretation of the guidance is outside of the industry norm.

Given the materiality of the forecasts that are being carved-out for bespoke assessment (£84 million), we believe Ofgem should use a consistent approach for all DNOs.

Core-Q71. Do you agree with our proposed assessment approach for connections?

We disagree with Ofgem's move away from a blended median unit cost used in RIIO-ED1 to a more disaggregated unit cost per voltage-based approach. This change seems to uplift industry wide totex by £100 million with very little evidence as to why this change is in customers' interest. Furthermore, whilst the impact on UK Power Networks at group level is negligible, there is a DNO to DNO rebalancing of over £40 million.

Moving to the disaggregated unit costs for different voltages increases the coefficient of variation of the data set being used to model the median. This is in stark contrast to the approach to Asset Replacement where Ofgem argues that higher coefficient of variations represents data quality concerns that provides reason for the data to be disregarded. Aside from the inconsistency between Ofgem's approach to connections and Asset Replacement, we consider that Ofgem has made an error in the use of "coefficient of variation" as a method for determining which datasets to make use of. However, we do believe there is merit in recognising that the more disaggregated the analysis is undertaken the greater the likelihood of spurious results being obtained – this is clearly evident in Ofgem's modelling of connections.

The "gross to net of income adjustment" assumes that income is constant when costs are reduced through the benchmarking. This is unsupported by the evidence as there is a clear relationship between gross costs and customer contributions. We propose that Ofgem removes this "gross to net adjustment", and the conversion from "gross to net" after allocations allowances is performed in one adjustment.

We also disagree with the concept of assessing and varying connections inside price control whilst holding connections outside price control constant. Any reduction in inside price control costs should be proportionately matched to the outside price control costs and the non-price control allocations. This includes income allocations between Connections inside price control and indirects/non-op capex.

In addition, please see our response to Core-Q68 above for service reinforcement. Given that we had followed the Business Plan Guidance in placing fuse upgrades under connections we would like to better understand the proposed revised approach to benchmarking fuse upgrades and unlooping ahead of Final Determinations. We understand that through an information request issued in August 2022 Ofgem is seeking to collect data to assist in additional benchmarking for this area.

Core-Q72. Do you agree with our proposed assessment approach for NTTC expenditure?

We do not agree with Ofgem's assessment approach for NTTC expenditure. Ofgem confirmed in a Cost Assessment Working Group (CAWG) that all New Transmission Capacity Charges (NTTC) costs would be funded with a pass through. We were surprised to discover that this was not the approach in the Draft Determinations and we do not understand the rationale for the change from the position which had previously been advanced.

If NTTC costs are to be funded in ex-ante allowances rather than pass through, updated information from National Grid – which was received in June 2022 - must be factored in for the Final Determinations. It is a regulatory principle that the most up-to-date information should be used. Please see our supplementary documents “CV4 NTTC-additional information” for supporting evidence and commentary.

Core-Q73. Do you agree with our proposed assessment approach on asset replacement?

We fundamentally disagree with the way Ofgem's Engineering Hub has carried out its assessments.

Through the Supplementary Question process, we have sought clarity over the disconnect between the EJPs assessment and Ofgem's resultant proposals on allowed cost. The common cause of discrepancy is something that Ofgem describe as “portfolio deliverability”. We understand that this phrase refers to instances where our actual spend on a particular category of expenditure in RIIO-ED1 varies from the allowed spend. In these instances, Ofgem's Engineering Hub has set the allowance for that category of expenditure to zero, regardless of the level of actual expenditure. The stated rationale for doing this is that any divergence between actual and planned expenditure undermines Ofgem's confidence in UK Power Networks' genuine intention to spend money on this category of expenditure in the future. This approach is not supported by the evidence and is irrational.

Through our bilateral engagement with Ofgem post Draft Determinations, we have explained how variance in delivery should not be viewed as negative. Variance in fact reflects the fact that the regulatory framework focuses on outputs, not inputs, to give DNOs flexibility to plan their activities. There are three main drivers that have contributed to the variance identified in our RIIO-ED1 delivery:

- Our RIIO-ED1 Business Plan was submitted in 2013 in which we were forecasting intervention volumes up to 10-years in the future. New information, priorities and emerging issues present themselves in period and we must respond to these to ensure network integrity;
- The RIIO-ED1 Ofgem Final Determinations resulted in a 14% cut to our asset replacement allowances. This immediately forced us to reassess our planned interventions, particularly large capital programmes to ensure we could operate within the allowances provided and deliver the risk reductions that are specified in our licence; and
- The introduction of CNAIM in 2017 resulted in large risk movements within some asset categories. For example, for HV switchgear - distribution, almost 70% of forecasted HI4s and HI5s at the end of the RIIO-ED1 period were reclassified as HI1, 2 and 3. This meant there were no longer enough HI4 and 5 assets to intervene on to deliver in line with requested business plan volumes.

The above three factors explain why there is a disconnect from submitted volumes and why an efficient, high performing business should continually update its intervention strategy to deliver its regulatory outputs and RIIO-ED1 commitments at the lowest cost without compromising network performance.

In response to Ofgem's Engineering Hub's request to provide further justification, and evidence our asset management strategy (in RIIO-ED1 and that proposed for RIIO-ED2), we have included detail in our “Non-Load Engineering Response”. This document is provided with the view to allow Ofgem to update its assessment and remove the current zero allowances and reduced volume assessment placed on a number of asset categories.

Following Ofgem's review of this report, we are available for further engagement and/or to provide additional information as appropriate since holding these asset classes to zero allowances at Final Determinations is an untenable position.

Core-Q74. Do you agree with our assessment approach to refurbishment?

We fundamentally disagree with the approach that Ofgem has adopted. Ofgem has acknowledged its spreadsheets contain errors that need to be fixed in the Final Determinations³⁶. Correcting errors in the spreadsheets is welcomed but this will not be sufficient to address our concerns which are fundamental.

Ofgem has argued that we do not need to incur asset replacement costs because it would be more cost effective for us to refurbish assets instead. We categorically disagree with Ofgem's approach. However, if Ofgem was being consistent our refurbishment numbers should have been increased, to reflect the presumption that asset replacement should be substituted by refurbishment. For the avoidance of doubt, we are not recommending that Ofgem reduces asset replacement and increases refurbishment funding. We are merely pointing out the conflicting information we have received. It is illogical and untenable to argue that asset replacement activity can be substituted by refurbishment activity and then provide no funding for the additional activity. This would leave us unfunded for a material part of our functions without adequate or any justification.

Core-Q75. Do you agree with our proposed assessment approach for asset replacement driven civil works?

Yes, we agree that the disaggregated asset replacement driven civil works approach is broadly appropriate and the selection of both the RIIO-ED1 and RIIO-ED2 time periods facilitates the calculation of a credible intervention rate.

We note that Ofgem has chosen to select all asset replacement expenditure as the denominator and grouped expenditure across all voltage levels to derive the industry median intervention rate.

Core-Q76. Do you agree with our proposed assessment approach for Condition Based Civil Works?

Yes, we agree that the disaggregated condition driven civil works approach is broadly appropriate and the selection of both the RIIO-ED1 and RIIO-ED2 time periods facilitates the calculation of a credible intervention rate.

We note Ofgem has used an industry median unit cost at the individual category level, e.g. Civil Works at HV Outdoor Substations, calculated from the RIIO-ED1 and RIIO-ED2 time periods. We recognise this provides more stable unit costs than purely focussing on the RIIO-ED2 period. For example, had Ofgem relied purely on the RIIO-ED2 forecast unit cost for Civil Works at 66kV Substations this would have been £14.9k whereas, over the combined RIIO-ED1 and RIIO-ED2 periods this is £11.5k, which, given the small number of DNOs undertaking activity on such substations appears to provide a more robust benchmark and is supporting evidence for Ofgem's choice of time periods in this instance.

Core-Q77. Do you agree with our proposed assessment approach for diversions?

We disagree with Ofgem refusing our proposed UM for diversions. We followed Ofgem's guidance in good faith and only included high confidence diversion costs in our ex-ante request, leaving an additional £181 million spend to be funded through our proposed UM. We think that this is the most efficient approach for funding diversion costs which are customer-driven, highly uncertain and not within our control. Ofgem's approach will lead to higher costs for customers and does not live up to its ambition to implement an agile price control. In addition, we find it strange that Ofgem has included UMs for both the gas distribution and electricity transmission sectors but has irrationally rejected the inclusion of such a mechanism for electricity distribution. This would seem to go against the requirement on Ofgem to act consistently and predictably and in a non-discriminatory way. As set out in our Business Plan submission, we believe Ofgem's cost assessment for diversions needs to take into account differing land values across the country. The failure to incorporate this in the benchmarking places UK Power Networks at a disadvantage given the parts of the country we serve.

³⁶ This error was identified by ENWL in Gitlab issue #92. Ofgem confirmed the error in the 33kV Transformer (GM) naming within the model and proposed to rectify this ahead of Final Determinations.

Please see our supplementary documents “CV5 Diversions-additional information” for supporting evidence and commentary.

Given Ofgem’s decision to not include a UM for diversions, we have submitted additional totex as part of our ex-ante request.

Core-Q78. Do you agree with our proposed approach for Rail Diversions?

Yes, we agree with Ofgem’s approach for Rail Diversions, which is consistent with RIIO-ED1.

We note that Ofgem’s decision on Rail Diversions is not consistent with its refusal to introduce a UM for diversions. As discussed in our response to Core-Q77 above, we think that the magnitude of diversions costs and the fact that they are externally driven warranted the introduction of an UM.

Core-Q79. Do you agree with our proposed approach to assessing Non-Operational, Operational and Business Support IT&T costs?

We do not agree with Ofgem’s proposed approach to assessing these cost categories.

Although the Core Methodology document suggests that Ofgem took account of a qualitative and quantitative assessment, there is no evidence that Ofgem attached any weight to the qualitative assessment. UK Power Networks provided Ofgem with an independent, expert assessment of our projected IT spend. We also submitted what Ofgem has indicated was an industry-leading DSO plan. Despite this, Ofgem is proposing to disallow a significant proportion of our proposed expenditure.

In addition, we disagree with the breadth of activities that Ofgem has modelled using a Modern Equivalent Asset Value (MEAV) cost driver. We do not consider the activities are comparable or that these costs are driven by MEAV. For example, SSEH’s MEAV is increased because the company’s asset base includes a high value submarine cable. However, we do not think this increase in MEAV justifies an increase in their need to invest in LV monitoring.

Please see NERA document, section 5.2 for supporting evidence and commentary.

Core-Q80. Do you agree with our proposed assessment approach for Legal and Safety?

We do not agree with Ofgem’s proposed assessment approach for Legal and Safety for two reasons. We ask that Ofgem considers our position in its Final Determinations.

- **We do not agree with Ofgem’s use of MEAV to determine the costs associated with Legal and Safety.** This approach does not take into account changes in strategy from one period to the next. For example, our strategy for cable pit mitigation in RIIO-ED1 has in the main focussed on filling identified pits with sand or to install a vented cover. Whilst both options are effective at lowering the risk associated with cable pits, they do not prevent continued inspection and maintenance costs or remove the risk entirely.

As detailed in our EJP-RP-06, in RIIO-ED2 we seek to increase the use of permanent reinstatement of cable pits. This will create a higher upfront unit cost because of increased traffic management and the chosen top surface finish (i.e. if bespoke and not standard paving slab or tarmac). However, permanent reinstatement does not require ongoing inspection and maintenance costs and is successful in removing any ongoing public safety risk, which is particularly important within the high-footfall areas of London, for example.

At present, Ofgem’s use of MEAV to determine costs makes no allowance or adjustment for our change in strategy for RIIO-ED2; and

- **We do not agree with Ofgem’s decision to disallow 100% of all costs associated with fire suppression.** Additional evidence and justification for this expenditure is provided in our “Non-Load Engineering Response”.

Core-Q81. Do you agree with our approach to assessing Overhead Line Clearance costs?

We agree with Ofgem's proposal to use a blended approach of total costs across the RIIO-ED1 and RIIO-ED2 periods to generate the industry median unit cost as it is a broadly similar mix over time periods.

Core-Q82. Do you agree with our proposed approach to assessing ESR costs?

We do not agree with Ofgem's approach to assessing ESR costs.

The UK Government has advised that there will be new ESR requirements, which have not yet been published. As we are unclear about what the guidance will stipulate, we did not submit costs in our ex-ante request.

We believe that, either there should be no ex-ante allowance for any DNO with access to a UM for ESR or, all DNOs should be provided with an equivalent level of ex-ante funding and access to the proposed UM once the new ESR requirements are published. We noted in the Draft Determinations that the disaggregation assessment shows that SP has received £6.5 million and SSE has received £5.6 million.

We are concerned that Ofgem's position on ESR costs could create a similar situation as we have seen in RIIO-ED1 with Rail Electrification Diversions costs, where one DNO received ex-ante funding whilst the other five DNO groups had a UM. This resulted in Ofgem needing to rely on the RIIO-ED1 mid-period re-opener to claw unnecessary allowances from the one DNO, rather than having it covered by a UM.

Core-Q83. Do you agree with our proposed approach to assessing QoS and NoSR costs?

As explained in our response to Core-Q49, we agree with the proposed approach to assessing QoS.

Core-Q84. Do you agree with our proposed assessment approach for Physical Security?

We agree with Ofgem's proposed assessment for Physical Security.

Core-Q85. Do you agree with our proposed assessment approach for Flood Mitigation?

We do not agree with Ofgem's approach. Ofgem states that it accepts costs and volumes submitted by DNOs where the EJP was approved³⁷. However, in the assessment, Ofgem has applied a 13-year median unit cost instead of the costs in the EJP. This approach of using a 13-year median unit cost fails to reflect the variety of circumstances around flood mitigation and of solutions used by DNOs. For example, it fails to differentiate the frequency of the events the licensee is addressing, which in turn impacts the complexity of the intervention involved. We also note the very varied unit cost for delivering flood resilience across the DNOs which we believe to be indicative of more than just differences in efficiency.

To remedy this error, **Ofgem should return to the RIIO-ED1 approach, which used a risk-based approach to assessing costs and was therefore more reflective of the circumstances.**

Additional information on our flood mitigation programme is also included within our "Non-load Engineering Response" supplementary document.

Core-Q86. Do you agree with the proposed approach to assessing Rising and Lateral Mains costs?

We do not agree with Ofgem's decision to disallow 100% of allowances associated with rising and lateral mains works. Additional evidence and justification for this expenditure is provided in our "Non-Load Engineering Response" and we would ask that Ofgem reconsiders this evidence in reaching its Final Determinations.

³⁷ RIIO-ED2 Draft Determinations, Core Methodology, paragraph 7.293

Core-Q87. Do you agree with our approach to assessing WSCs?

We agree with Ofgem's approach to assessing WSCs.

Core-Q88. Do you agree with our proposed assessment approach for Losses?

We agree with Ofgem's proposed assessment approach for losses.

Core-Q89. Do you agree with our proposed assessment approach for environmental reporting?

We accept the approach for all areas of environmental reporting apart from PCB. Please refer to our response to Core-Q90 where we explain that we think that both costs and volumes should be reported by DNOs, to allow for a more robust cost assessment.

Separately, Ofgem has requested further information on carbon offsetting³⁸ which we have supplied in our "Carbon offsetting" supplementary document

Core-Q90. Do you agree with our proposed assessment approach for PCBs?

We disagree with the proposed assessment approach for PCBs. The approach of generating a combined RIIO-ED1 and RIIO-ED2 aggregate unit cost for each DNO and using this to determine RIIO-ED2 allowances is an error, for the following reasons:

- **The combined aggregate unit cost fails to reflect the changing mix of PCB activities over the respective periods.** For example, for EPN, we move from oil inspections being 85% of the total RIIO-ED1 expenditure, to being 40% of RIIO-ED2 total PCB-related expenditure. The RIIO-ED2 industry median unit cost for oil inspections being circa £90 an inspection. Conversely, physical replacement of PMTs, with an industry median unit cost of £4,568 per asset in RIIO-ED2 goes from being 15% of EPN's expenditure to 45% in RIIO-ED2. At an industry level, the respective movements in oil inspections between RIIO-ED1 and RIIO-ED2 and PMT replacements are 80% to 33% and 19% to 62% respectively. Such a material movement in the composition of PCB-related activity cannot be dealt with by using a composite unit cost across all activities;
- **Unit cost analysis should be done at an individual category level as noted above.** Given the observed variability in the reported data, we believe the industry median values at each activity level should be determined from the RIIO-ED2 data – noting that RIIO-ED2 makes up 86% of the total expenditure forecast to be spent on addressing PCBs across RIIO-ED1 and RIIO-ED2;
- **Failing to conduct any inter-DNO efficiency analysis produces perverse results.** For example, the approach of giving DNOs their own combined RIIO-ED1 and RIIO-ED2 unit cost for RIIO-ED2 results in no reductions to allowances for a number of DNOs, even though their RIIO-ED2 unit costs are significantly higher than the industry median for key activity categories, e.g. DNO RIIO-ED2 unit cost of £5,000 per PMT replacement compared to an industry median unit cost of £4,568. Conversely, EPN, with a unit cost equal to the industry median for PMT replacements, is seeing a significant reduction to overall RIIO-ED2 PCB allowances;
- Our understanding of Ofgem's policy intent is that there will be a volume driver for PMT-related activities and an ex-ante allowance for GMT-related activities. The current benchmarking approach combines all activity volumes and costs. **GMT activities need to be assessed separately and the associated allowances clearly demarcated from those subject to the volume driver. We would ask that Ofgem reconsiders its approach in reaching its Final Determinations;** and
- We note there are instances of volumes but no costs being reported. We believe this relates primarily to inspections, where costs may be reported against the primary driver, but a count has also been included in the PCB table for visibility of activity to ascertain exposure to PCB replacement volumes. **We would**

³⁸ RIIO-ED2 Draft Determinations, Core Methodology, paragraphs A1.43 and A1.44

request that unit costs are only derived for periods where there are both costs and volumes reported i.e. if a DNO has reported zero expenditure for inspections in RIIO-ED1 but a volume count, this volume count is not used in the denominator for calculating combined RIIO-ED1 and RIIO-ED2 unit costs.

Core-Q91. Do you agree with our proposed assessment approach for Property?

We agree with the proposed assessment approach for Property.

Core-Q92. Do you agree with our proposed assessment approach for STEPM?

We agree with the proposed assessment approach for Small Tools, Equipment, Plant and Machinery (STEPM).

Core-Q93. Do you agree with our proposed assessment approach for Vehicles and Transport?

We do not agree with Ofgem's approach, and we make five observations.

- First, Ofgem models vehicle and transport costs by using MEAV as a cost driver. Along with other DNOs, to play our part in the transition to Net Zero, we are proposing to convert our fleet to low carbon vehicles. Historical information on vehicles and transport reflects the use of vehicles powered by internal combustion engines, rather than low carbon technologies. The use of MEAV to model allowed costs is an error as it is not representative of future costs;
- Second, the DNOs have different ambitions for converting their fleets. It would be wrong to normalise for these differences in a way that penalised the more ambitious DNOs;
- Third, UK Power Networks provided Ofgem with investment case documentation which set out the justification for our investment in this area. There is no evidence in the Draft Determinations that Ofgem has considered this documentation in coming to its judgement on allowed vehicle and transport expenditure;
- Fourth, we put forward our proposals to decarbonise our fleet to deliver our Science Based Target Initiative (SBTI) commitment. The diesel consumed in our fleet made up over 40% of our Business Carbon Footprint in 2018/19. If the conversion of our fleet to low carbon technology is not appropriately funded, it will affect our ability to meet our SBTi requirements; and
- Five, as set out in Supplementary Question 5, Ofgem has acknowledged that it has made an error in the way that the Price Control Financial Model (PCFM) categorised this expenditure. This error will need to be corrected.

Core-Q94. Do you agree with our proposed assessment approach for HVPs?

Whilst we have reservations about the late change to Ofgem's position with respect to High Value Projects (HVPs), given our response to Q4 we agree with Ofgem's proposed assessment approach for HVPs. As part of Ofgem's disaggregated cost assessment, we believe Ofgem should undertake some cross-checks between Asset Replacement and HVPs to ensure that DNOs without HVPs are not disadvantaged in Ofgem's run-rate and survivor modelling.

Core-Q95. Do you see any merit in setting a HVP threshold for RIIO-ED2, and if so should it be based on the RIIO-ED1 threshold?

Yes, as per our response to Core-Q4, we see merit in continuing with the RIIO-ED1 threshold.

Core-Q96. Do you agree with our proposed assessment approach for faults and ONIs?

We agree with Ofgem's proposed assessment approach for faults and Occurrences Not Incentivised (ONI).

Core-Q97. Do you agree with our proposed assessment approach for Tree Cutting?

We accept Ofgem's proposed assessment approach for tree cutting. However, Ofgem has applied a median unit cost to all volumes, combining spans cut and spans inspected. We note that these two activities typically generate substantially different unit costs. As such, Ofgem might want to consider whether its modelling caters adequately for these circumstances. More specifically, Ofgem's approach combines tree cutting and inspection volumes into a single number. UK Power Networks uses helicopters to carry out inspection work. As a result, Ofgem's approach is favourable to UK Power Networks.

Core-Q98. Do you agree with our proposed assessment approach for Severe Weather 1-in-20 Events?

We are comfortable with Ofgem's assessment approach for Severe Weather 1-in-20 Events. However, this is subject to agreement of details in any guidance provided on qualifying costs and exclusions as discussed at the SRRWG on 28 July.

Core-Q99. Do you agree with our proposed approach to assessing Inspections and Repair & Maintenance costs?

For EPN and SPN, the approach looks acceptable. However, for LPN, the approach needs refining.

We believe that the use of a MEAV driver overlooks network variations such as the lack of an overhead network in LPN and the location of high-profile sites, such as in London, where we need to undertake enhanced maintenance regimes. In addition to our broader comment on the selection of the right activities to include in MEAV i.e. not to include protection assets, we would advocate an adjustment for LPN to recognise the skewed composition of its MEAV compared to the rest of the industry. Overhead assets comprise 0% of LPN's MEAV, compared to an industry average of 15%. Such an adjustment would be consistent with the approach Ofgem took at RIIO-ED1³⁹. We would ask that Ofgem reconsiders this evidence in reaching its Final Determinations

Core-Q100. Do you agree with our proposed assessment approach for NOCs other?

We agree with the approach for assessing the costs of dismantlement and remote generation.

We disagree with the approach Ofgem uses for assessing substation electricity costs. Given the current market volatility in electricity prices, we cannot see the relevance of using historic RIIO-ED1 rates to set RIIO-ED2 allowances, which should be set on an ex-ante basis rather than adopting out-of-date data. Indeed, we currently project substation electricity costs in RIIO-ED2 to be double the level seen in RIIO-ED1. We estimate the exposure to currently reach £150 million across all DNOs.

We consider there is a very strong case for a Real Price Effects (RPE)-type adjustment to allow for further movements in the prices of electricity to be funded or returned to customers. We believe this would be an appropriate protection for customers and DNOs given current market turbulence.

³⁹ RIIO-ED1: Final Determinations for the slow-track electricity distribution companies, Business plan expenditure assessment, page 26

Core-Q101. Do you agree with our proposed assessment approach for Smart Metering Rollout?

As noted above in Q5, we disagree with the removal of the volume driver which afforded both customers and DNOs protection.

The benchmarking approach uses an industry median intervention rate of three percent. This is in line with what UK Power Networks would expect if we were to put in a plan using ex-ante funding and no variable volume driver. However, this does result in a change in allowance composition across our three DNO away from the expenditure seen in history.

Core-Q102. Do you agree with our approach to assessing CAI costs?

We disagree with Ofgem's approach to assessing Closely Associated Indirect (CAI) costs. Please see NERA document, section 5.1 for supporting evidence of our position.

Core-Q103. Do you agree with the proposed assessment approach for Business Support costs?

We disagree with Ofgem's approach to assessing Business Support Costs. Please see NERA document, section 5.1 for supporting evidence of our position.

Core-Q104. Do you agree with our approach to assessing streetworks costs?

We do not agree with Ofgem's approach to assessing streetworks costs. The use of the ratchet⁴⁰ affects UK Power Networks the most, with Ofgem's modelling indicating we would receive an additional £30.9 million (circa 42% more than forecast), whereas the ratchet results in an overall reduction of £5 million (circa 7% reduction). Overall, this reduces the Ofgem modelled view by c. £36 million for UK Power Networks. This is a further example of how Ofgem's use of ratchets in its cost assessment unduly punishes efficient DNOs and contributes to the position where UK Power Networks is not receiving a BPI stage 4 reward. We would like a consistent approach whereby the ratchet is not used, and the Ofgem modelled costs are used for allowance setting.

Core-Q105. Do you agree with our proposal to carry out a demand driven post- modelling adjustment?

We disagree with Ofgem's proposal to carry out a demand drive post-modelling adjustment. Please see NERA document for supporting evidence section.

Core-Q106. Do you agree with our proposal to not carry out any Quality of Service based adjustments?

We do not agree with Ofgem's proposal. We believe an adjustment could have been made which factors in the monetised value of the combined CIs and CMLs experienced by customers in each DNO. We have previously shared an approach to doing this with Ofgem during a bilateral held on 13 August 2021.

We consider it is particularly important to do this in a world where customers place increasing importance on the reliability of their electricity supply, for example, as a result of the more prevalent use of internet broadband services, the greater take-up of home working; the wider use of electricity for heating; and/or the greater deployment of electric vehicles.

⁴⁰ A ratchet is where Ofgem compares Ofgem modelled costs to DNO submitted costs and set the modelled output as the lower of the two.

Core-Q107. Do you agree with our approach to combining our totex and disaggregated benchmarking models?

We disagree with Ofgem's approach to combining totex and disaggregated benchmarking models. Please see NERA document, section 7 for supporting evidence.

Core-Q108. Do you agree with our approach to setting and applying the efficiency challenge using a glide path between the 75th and 85th percentile over a 3-year period?

We disagree with Ofgem's approach. Please see NERA document, section 7 for supporting evidence.

Core-Q109. Do you agree with our proposed RPEs allowances? Please specifically consider our proposed notional cost structure, assessment of materiality, and choice of indices in your answer.

We do not agree with the proposed RPEs allowances. The detailed arguments in support of our view can be found in NERA's Report on "Response to RIIO-ED2 Draft Determinations on Real Price Effects". The key points that NERA make are summarised, as follows.

- **CEPA combines all labour costs into a single cost category.** In CEPA's analysis, "General Labour" (25% of DNOs' total costs) and "Specialist Labour" (38% of DNOs' total costs) are combined into a single, homogenous cost category that are therefore expected to face common external price pressures. By failing to separately account for the two different and significant labour costs categories, there is a risk that Ofgem is understating the RPEs and hence is making an error. CEPA's rationale for combining the categories is that there is difference in classification across the DNOs. Ofgem should seek to understand the differences in classification rather than apply a high-level adjustment;
- **CEPA unjustifiably applies an RPE allowance of zero to some cost categories.** CEPA deems that "Plant and Equipment" (3% of DNOs' total costs), and "Transport" (2% of DNOs' total costs) costs categories have low materiality (accounting for less than 5% of DNOs' total costs) and therefore an RPE allowance is not required. Similarly, while the "Other" cost category accounts for seven percent of DNOs' total costs, CEPA deems it is insignificant and again no RPE is applied;

However, we note that Ofgem has applied ongoing efficiency (OE) to these costs which is inconsistent. As NERA's report suggests, we support applying RPEs to all three categories as follows:

- "Plant and Equipment" and "Transport" should be combined and an RPE for this category calculated using "BCIS PAFI plant and road vehicles (90/2) index",
- RPEs for the "Other" cost category should be calculated using the ONS' output producer price index (PPI), which is more likely to reflect the cost pressures DNOs face more closely than CPIH does.
- **CEPA does not update the notional cost structure for Draft Determinations proposals** – The notional cost structure derived by CEPA is based on BPDTs submitted by the DNOs. However, as Ofgem has disallowed costs from specific cost categories in Draft Determinations, the DNOs notional cost structures must have changed. For the Final Determinations Ofgem must ensure that the notional cost structure reflects the costs it has allowed.

Core-Q110. Do you agree with our proposed approach to setting the ongoing efficiency challenge and the level of challenge applied?

We do not agree with the proposed approach to setting the OE challenge and the level of challenge applied in the RIIO-ED2 Draft Determinations. As detailed in NERA's "Response to RIIO-ED2 Draft Determinations on Ongoing Efficiency" and Frontier's "RIIO-ED2 Productivity Target" reports, the proposed OE assumption in the RIIO-ED2 Draft Determinations of 1.2% per annum is based on a flawed interpretation of data.

The primary source in CEPA's analysis to inform productivity targets is growth accounting analysis drawing on the EU KLEMS database. While CEPA presented a range of values of historical growth rates from 0.2% using a Gross

Output (GO) measure for a narrower comparator set (developed for RIIO GD2/T2) to 1.2% using a Valued Added (VA) measure for an expanded⁴¹ comparator set (developed for RIIO-ED2), Ofgem has chosen to dismiss the GO-based analysis and place more weight on the expanded comparator set. Ofgem have not sufficiently justified why it is appropriate to select the upper bound of the values determined by CEPA and we note that VA measures are consistently higher and are often more than double when compared to similar GO measures. Furthermore, the expanded comparator set contains the Information and Communication sector, which experienced transformational change in the late 1990s and early 2000s and its inclusion in the comparator set is likely to exaggerate OE over RIIO-ED2.

Ofgem has also taken the effect of innovation funding into their consideration of an appropriate OE target. However, this is only briefly explained and has not been supported by any quantitative evidence by Ofgem in the Draft Determinations. We note that at the RIIO-2 CMA appeal the CMA dismissed Ofgem's innovation efficiency-related quantitative analysis as not robust and struck out the additional 0.2% efficiency challenge that Ofgem had proposed. To overcome this issue Ofgem's approach for the RIIO-ED2 Draft Determinations is to provide only qualitative evidence to support their assertion that there is significant innovation ongoing efficiency benefit available in RIIO-ED2.

Furthermore, CEPA has incorrectly interpreted the values included in the OE table within our BPDT. They have wrongly concluded that we included an OE assumption of 1.4% per annum across the RIIO-ED2 period. This misinterpretation, which we have highlighted to Ofgem, should not be used to justify the 1.2% value for OE.

Core-Q111. Do you agree with our proposed disaggregation methodology?

We disagree with the simplified proposal. As discussed in our bilateral, the current approach provides funding in areas that have received significant disaggregation cuts and conversely penalises areas where DNOs have performed well in disaggregated analysis. This creates significant unit cost distortions to cost and volume tables where the volume treatment is disconnected from the cost treatment.

At the CAWG-28 meeting on 23 August 2022, UK Power Networks presented an alternative approach.

QUESTIONS IN THE DRAFT DETERMINATIONS - FINANCE ANNEX

Cost of capital overarching summary

It is vital that we can continue to attract the necessary debt and equity funding that will allow us to deliver on our commitments. This requires Ofgem to set:

- An allowed cost of debt that appropriately remunerates efficiently incurred embedded and new debt and which also considers the current level of macro-economic uncertainty; and
- An allowed cost of equity which is set at level that compensates investors for the risk that the company is bearing and which will impact on the returns which investors will recover.

Ofgem's current proposals achieve neither of these objectives.

With respect to the **allowed cost of debt**, Ofgem's baseline cost of debt allowance underfunds the sector's debt costs and in contrast to the decision for gas distribution and transmission, provides no headroom for macro-economic uncertainty which has increased materially since the gas distribution and transmission Final Determinations and the subsequent CMA appeals. This approach significantly increases the risk profile of electricity distribution relative to the other energy network sectors.

On the **cost of equity**, the Oxera report⁴² highlights that Ofgem has made several methodological errors in its derivation of the cost of equity. These include:

- Ofgem has erred by setting the **Risk-free Rate (RfR)** at the level of government bond yields. Government bond yields embed a convenience premium and therefore are below the returns on a zero-beta asset,

⁴¹ RIIO-ED2 expanded comparator set have included two new sectors: (1) Professional, Scientific, Technical, Administrative and Support Services activities and (2) Information and Communication.

⁴² OXERA, 19 August 2022, Cost of Equity in RIIO-ED2 Draft Determinations

which is required to be used as a RfR in the Capital Asset Pricing Model (CAPM). It makes the use of unadjusted government bond yields inappropriate for the determination of the allowed RfR;

- Ofgem has erred by using a **Total Market Return (TMR)** estimate based on an outdated CPIH back-cast series. The new Office of National Statistics (ONS) Consumer Price Index with Housing Costs (CPIH) back-cast series is more robust than the previous one and therefore should be used to deflate historical returns; and
- Ofgem has erred by placing too much weight on the **beta** of water companies. The newly developed evidence shows that there are significant differences between water and energy networks and that, at a minimum, Ofgem should also have placed weight on the betas of European energy companies. In other words, Ofgem's error is in the emphasis it puts on the beta of water companies while precluding any weight on European energy companies.

Correcting for these errors results in **a cost of equity of at least 5.5%** which we believe is a more appropriate level, considering the need to attract and retain investment and provide financial resilience.

Finally, please note that all the documents referenced in support of our positions below have been submitted separately by the Energy Networks Association (ENA) on behalf of all network operators.

Consultation question on allowed return on debt

FQ1. Do you agree with our approach to estimating efficient debt costs and setting allowances for debt costs?

We are concerned that Ofgem has taken a significantly different approach to setting the cost of debt allowance for electricity distribution compared to that taken for the gas and transmission companies. The table below shows that Ofgem's chosen index will under-remunerate the electricity distribution sector under the base case and if derivatives are included this under-performance could rise to 23bps⁴³.

Table 16 - Ofgem index debt calibration analysis*

Calibration approach	Base	Inflation +1%	Inflation -1%	IBoxx and LIBOR +1%	IBoxx and LIBOR - 1%
10yr + 25 bps costs	-0.82%	-0.92%	-0.71%	-0.91%	-0.72%
15yr + 25 bps costs	-0.25%	-0.36%	-0.15%	-0.41%	-0.09%
17yr + 25 bps costs	-0.02%	-0.13%	+0.08%	-0.20%	+0.15%
18yr + 25 bps costs	+0.07%	-0.04%	+0.18%	-0.11%	+0.25%
20yr + 25 bps costs	+0.21%	+0.11%	+0.32%	+0.02%	+0.40%
10-14yr + 25 bps costs	-0.47%	-0.58%	-0.36%	-0.62%	-0.32%
11-15yr + 25 bps costs	-0.35%	-0.46%	-0.25%	-0.51%	-0.20%
10-20yr + 25 bps costs	+0.17%	+0.06%	+0.28%	-0.02%	+0.36%

*Taken from the RIIO-ED2 Draft Determinations, Finance Annex, Table 7

⁴³ RIIO-ED2 Draft Determinations, Finance Annex, paragraph 2.62

By contrast, in RIIO-GD2/T2, Ofgem allowed between 26bps and 29bps of headroom, as shown below. It also stated that its chosen debt index was sufficient to cover debt costs including derivatives⁴⁴.

Table 5: FD debt allowance calibration compared to expected GD&T debt costs under different scenarios

Scenario/ Assumption	Net Zero 2 Totex	Ofgem FD Totex
March '20 OBR RPI Forecast	0.29%	0.26%
RPI +1%	0.03%	-0.02%
RPI -1%	0.53%	0.51%
Long Term RPI = 3%	0.26%	0.22%
RPI 3%, Iboxx & LIBOR +1%	0.11%	0.10%
RPI 3% Iboxx & LIBOR -1%	0.40%	0.34%

** Taken from the RIIO-GD/T2 Final Determinations, Finance Annex*

A key rationale for Ofgem allowing this headroom in RIIO-GD2/T2 was to cater for uncertainty in the macroeconomic environment. The macroeconomic situation facing the electricity distribution sector is more uncertain than at the time of the RIIO-GD2/T2 decision. Therefore, we believe that Ofgem should adopt the 20yr +25bps costs index as this provides a similar level of headroom as that provided to the gas distribution and transmission companies.

We also note that Ofgem has undertaken additional analysis that indicates there is an increased positive halo effect for electricity distribution bond issues relative to the Utilities index and hence it does not need to include an allowance for a new issue premium in its allowance for borrowing costs. However, as Ofgem states in paragraph 2.15 of the Finance Annex, the impact of electricity suppliers issuing debt during the pandemic may explain the increase in Ofgem's calculated halo rate. Furthermore, as Ofgem is setting the allowed cost of debt below the sector's observed debt costs, it is capturing any perceived halo (or a proportion of it). Therefore, we remain of the view that Ofgem should allow a new issue premium of six basis points in its financing costs allowance, particularly in the light of the substantial requirement for the provision of new capital to support the Net Zero transition.

In summary, Ofgem's baseline cost of debt allowance underfunds the sector's debt costs and in contrast to the decision for gas distribution and transmission provides no headroom for macro-economic uncertainty which has increased materially since the gas distribution and transmission Final Determinations. This approach significantly increases the risk profile of electricity distribution relative to the other energy network sectors.

We also disagree with Ofgem's proposal not to apply an infrequent issuer premium to embedded debt.

Ofgem's principal argument is that, as it has matched the sectors' debt costs, it does not need to allow an infrequent issuer premium on embedded debt for the smaller companies. However, Ofgem has presented no analysis to support this assertion. Over the first seven years of RIIO-ED1, LPN has issued an average of circa £70 million per annum which illustrates that this is not a RIIO-ED2 only issue. Therefore, we believe that Ofgem should allow the infrequent issuer premium on embedded debt, otherwise it would under-remunerate LPN's efficient debt costs.

Step 1 - Consultation question on risk-free rate and equity indexation

FQ2. Do you have any views on the model to implement equity indexation that is published alongside this document, (the 'WACC Allowance Model - RIIO-ED2 30th April 2022 update Alternative Wedge')?

We disagree with Ofgem's approach to solely use index linked gilts as its only source for the RfR. As OXERA outlines in its report⁴⁵, Ofgem has erred in its approach because:

- **Ofgem failed to account for the convenience premium on Index-Linked Gilts (ILGs).** The CAPM assumes that all investors can borrow at the same RfR. However, even investors with the highest

⁴⁴ RIIO-GD/T2 Final Determinations, Finance Annex, paragraph 2.39

⁴⁵ OXERA, 25 August 2022, Cost of Equity in RIIO-ED2 Draft Determinations pages 4-8

creditworthiness face significantly higher borrowing rates than those faced by Governments with high credit ratings;

- **Academic literature supports the inclusion of a convenience premium.** For example, Krishnamurthy and Vissing-Jorgensen (2012)⁴⁶ conclude that: “*Treasury interest rates are not an appropriate benchmark for ‘riskless’ rates. Cost of capital computations using the capital asset pricing model should use a higher riskless rate than the Treasury rate; a company with a beta of zero cannot raise funds at the Treasury rate*”; and
- **There is growing regulatory precedent for the inclusion of a convenience premium.** In addition to the CMA PR19 determination, both ARERA (the Italian regulatory authority) and BNetzA (the German regulatory authority) have included convenience premiums in their calculation of the Risk-Free Rate.

Based on the above we believe that the convenience premium is between 50bps -100bps.

FQ3. In light of the upcoming change to the definition of RPI in 2030, should the RPI-CPIH inflation wedge be based on: a) a single year (as shown in the WACC allowance model when: cell D2 is “year 5 forecast” and cell B5 is “01/04/2022”); or b) should it be based on 20 years of inflation forecasts (as shown in the WACC allowance model when: cell D2 is “20 year geometric” and cell B5 is “01/04/2031”)?

We believe that method (a), which Ofgem uses in its current calculation of the RPI-CPIH inflation wedge, is understated by 30bps.

In method (a) Ofgem is using year 5 of the Office for Budget Responsibility (OBR) inflation forecasts which produces a wedge of 0.7%. Ofgem’s rationale is that this represents the best long-term inflation forecast. However, in its March 2022 publication, the OBR states⁴⁷: “*thereafter, we expect RPI inflation to rise a little as CPI inflation returns to target to reach around 2.7 per cent at the end of the forecast. This is slightly below the rate consistent with our current estimate of the long-term wedge between CPI and RPI inflation of around 1 per cent as the downward-sloping Bank Rate curve means we expect mortgage rates to fall slightly in the medium term [emphasis added]*”.

Method (b) assumes that the RPI reforms announced by the Chancellor in 2020 result in RPI and CPI being 100% aligned post-2030. There remains uncertainty over these reforms as a number of pension companies have been given permission to judicially review them⁴⁸.

Therefore, we believe that Ofgem should continue with method (a) but uplift the wedge estimate to 100bps.

Step 1 - Consultation questions on TMR

FQ4. Is there evidence that suggests we should change our approach to TMR for RIIO-ED2?

We remain of the view that utilising actual outturn averages to determine the TMR should be the prime methodology for setting the TMR for the cost of equity for RIIO-ED2. We believe that all cross-checks are subject to issues and, as such, the CAPM remains the most robust approach to determine the cost of equity.

As we set out in our answers to questions FQ10 to FQ13, and the evidence that we put forward there, we believe limited weight should be put on Ofgem’s preferred cross-checks, particularly those related to Market to Asset Ratios (MARs) and Offshore Transmission Owners (OFTO).

⁴⁶ Krishnamurthy, A. and Vissing-Jorgensen, A. (2012), ‘The Aggregate Demand for Treasury Debt’, *Journal of Political Economy*, 120:2, April, pages 233–67

⁴⁷ OBR, (2022), ‘Economic and fiscal outlook’, March, p. 40.

⁴⁸ [Pension schemes set for RPI/CPIH alignment appeal court case - Pensions Age Magazine](#)

We set out in our answer to question FQ6 that Ofgem has made two errors in its calculation of the TMR. These are:

- Ofgem has erred by using a TMR estimate based on an outdated CPIH back-cast series. The evidence we put forward in our response to FQ6 below shows that the new ONS CPIH back-cast series is more robust than the previous one and therefore should be used to deflate historical returns; and
- Ofgem has erred in calculating the TMR by using a geometric mean with an uplift rather than the arithmetic average.

FQ5. Can stakeholders confirm their view on the trade-off between: the objectivity of using outturn averages (even though the results may be materially higher or lower in future price controls than current TMR expectations); versus the benefits of putting more weight on current expectations (noting the evidence from cross-checks and the associated risk of subjectivity)?

Please refer to our answer to FQ4.

FQ6. Do stakeholders agree with our proposal to apply the same TMR for RIIO-ED2 (a mid-point of 6.5% CPIH) as we did for RIIO-GD&T2?

We believe that, in its calculation of the TMR, Ofgem needs to recalculate its real TMR estimate to:

- Take account of the ONS publication of revised historic CPIH data; and
- Use an arithmetic rather than a geometric mean to calculate the TMR.

With respect to the former, the ONS has published a new historical series for the CPI and the CPIH for the period 1950–88⁴⁹. As OXERA demonstrates in its paper⁵⁰, the impact of this change results in average inflation, over that period, being reduced by 0.24%, which translates into an increase in the CPIH-real equity returns of 0.24%. Given that the new ONS data suggests that CPIH inflation was 0.24% higher than the old estimates of CPI inflation over the period 1900–2021, the CPIH-real TMR should be corrected upwards by c. 0.25% (i.e. Ofgem's CPIH-real TMR range should be corrected to 6.50–7.00%).

Furthermore, Ofgem's use of the geometric average with an uplift is incorrect. The correct approach is to use the arithmetic average. As OXERA highlights⁵¹, Ofgem's proposed methodology is not correct because it is not substantiated by empirical evidence and it does not take into consideration the regulatory framework of setting allowed returns—that is, when setting allowed regulatory returns the regulator is setting a stream of annual cash flows (rather than cash flows that are compounded over time as a geometric averaging methodology would require).

On this basis we do not believe it is correct for Ofgem to set the TMR for RIIO-ED2 at 6.5%. Correcting for the above errors the TMR should be 7.1%- 7.2%.

Step 1 - Consultation questions on beta

FQ7. Do you believe that DNOs have a higher or lower level of systematic risk than the GD&T companies during their respective RIIO-2 periods?

We believe that DNOs have a higher level of systematic risk than GD&T companies. The rationale for this is:

- As demonstrated in our response to question FQ1 above, Ofgem's proposed electricity distribution cost of debt index allows materially lower headroom for macroeconomic volatility than that provided to gas distribution and transmission companies. This additional risk is borne by shareholders;
- The incentive package in electricity distribution is more asymmetric than either gas distribution or transmission. With respect to common ODIs, the range is typically 0.3% to -0.7% for gas distribution, 0.2%

⁴⁹ Office for National Statistics (2022), 'Consumer price inflation, historical data, UK 1950 to 1988'

⁵⁰ OXERA, 25 August 2022, Cost of Equity in RIIO-ED2 Draft Determinations, pages 12-18

⁵¹ OXERA, 25 August 2022, Cost of Equity in RIIO-ED2 Draft Determinations, pages 12-18

/ -0.7% for electricity transmission and 0.3% / - 0.3% for gas distribution. The equivalent range for electricity distribution is 1.95% to - 4%;

- The RIIO-ED2 price control framework is significantly more dynamic and complex than RIIO-GD2/T2 framework, as evidenced by the 33 UMs in the former compared to 17 in the latter; and
- Given the volume of UMs, electricity distribution companies are exposed to higher risk of mis-calibration of the mechanisms.

FQ8. What are your views on the relative risk comparison shown in Table 10?

Based on the points in our response to FQ7 above, **we believe that Ofgem's assessment of relative risk in Table 10 of the Finance Annex is incorrect and under-estimates the risks for DNOs relative to GD&T.** These additional issues should be included in the Table 10 analysis.

On the point in the table that gas distribution companies face greater stranding risks, we note that Ofgem's baseline Future Energy Scenario for RIIO-ED2 is System Transformation which assumes that the majority of home heating transitions to hydrogen.

Overall, therefore, we believe that the equity beta for electricity distribution should be set higher than that for gas distribution or transmission.

FQ9. Do you have any evidence that suggests the beta for GD&T companies has materially changed since RIIO-GD&T2 Final Determinations in December 2020?

The relevant question is whether Ofgem has set the equity beta for electricity distribution correctly. As we have demonstrated in our answers to FQ7 and FQ8, **we believe that the equity beta for electricity distribution is higher than either transmission or gas distribution.**

We continue to believe that Ofgem has erred and underestimated the RIIO-ED2 equity beta. This is because:

- **Disproportionate weight has been placed on the listed water company betas in the analysis** – OXERA's⁵² analysis shows that National Grid's asset beta has been consistently higher than the average asset beta of the water comparators. We note also that the asset beta of the average of the water companies has, in some of the regressions, fallen below the lower bound of the confidence interval for the NG beta estimate⁵³. This is supportive of a difference in the systematic risk of the UK listed water companies and National Grid;
- **While the equity beta that Ofgem has allowed is higher than that for the water companies, the size of the differential is insufficient.** As we highlighted in our Business Plan⁵⁴ and OXERA⁵⁵ has also highlighted, the risks associated with the regulatory regime of the water sector in the UK differ from energy networks despite similar models of economic regulation. An important difference is that, in the water sector, there is a process for redeterminations (by the CMA) compared to an appellate regime for energy networks. The outcome of the recent RIIO-2 appeals suggests there is more regulatory discretion (due to the margin of appreciation that is accorded by the CMA to the regulator) in the exercise of the appellate regime in energy. Higher regulatory discretion tends to imply higher risk to energy networks; and
- **Ofgem does not include beta evidence from other relevant comparators.** We continue to believe that Ofgem should expand its dataset to include other companies. In Table 4.3 of its report⁵⁶, OXERA shows that the systematic risk of a number of European Utilities is similar to that of National Grid. It is therefore illogical that Ofgem places weight on the equity betas of the listed water companies in its analysis, which

⁵² OXERA, 25 August 2022, Cost of Equity in RIIO-ED2 Draft Determinations, Section 4.1

⁵³ OXERA, 25 August 2022, Cost of Equity in RIIO-ED2 Draft Determinations, Figures 4.2 and 4.3

⁵⁴ Appendix 25b "The cost of equity for RIIO-ED2" of our RIIO-ED2 Business Plan, page 4

⁵⁵ OXERA, 25 August 2022, Cost of Equity in RIIO-ED2 Draft Determinations, Section 4.1

⁵⁶ OXERA, 25 August 2022, Cost of Equity in RIIO-ED2 Draft Determinations

have lower systematic risk than energy networks, but no weight on European energy utilities. We believe that Ofgem is making an error by not including these comparators in its beta assessment.

Step 2 - implied cost of equity consultation questions

FQ10. Do you agree with our interpretation of the cross-check evidence?

Please refer to our answer to FQ13.

FQ11. Do you agree with our updated MAR and OFTO cross-check techniques, in terms of drawing better inferences for RIIO-ED2?

Please refer to our answer to FQ13.

FQ12. Do you agree with the cross-checks we have used and are there other cross-checks we should consider?

Please refer to our answer to FQ13.

FQ13. Do you consider we should put greater weight on cross-checks or reconsider our CAPM parameters in light of the adjusted cross-check results?

We remain of the view that limited weight should be placed on the cross checks proposed by Ofgem and they should not be used as the prime method to set the cost of equity.

Ofgem's assumption that only a MAR close to one can confirm that a price control has been appropriately calibrated, can only hold under a very restrictive set of unrealistic assumptions. As highlighted by Frontier Economics⁵⁷, even if the regulator forecasts all aspects of the price control accurately (including totex) and all investors believe in expectation the outturn spend of regulated networks is equivalent to the expected spend and there is no room for any outperformance, the following conditions need to be met for MAR to be equal to one:

- Markets are efficient. This means that there needs to be perfect information, transactions are frictionless, and there is no information asymmetry;
- All investors are perfectly rational and have perfect foresight; and
- Investors also all need to employ the identical fundamental valuation approach for equity assets.

These conditions clearly do not hold in reality. If they did, we would not observe unexplained stock market fluctuations, e.g. the phenomenon of bull markets and bear markets, driven by market sentiment and momentum. In other words, market valuation is influenced by factors which are unpredictable, not based on fundamental valuation models and certainly outside the regulators' control.

Furthermore, as OXERA⁵⁸ highlights, there are several reasons why observed levels of MARs above 1x do not automatically mean that investors' required cost of equity is below the regulatory allowed CAPM-based estimate. These include:

- company-specific outperformance on financing and tax, ODIs, totex, and fast-track status (for water networks under Ofwat's regulatory regime);
- expected Regulatory Asset Base (RAB) growth, which strengthens the impact of outperformance;
- the value of non-regulated business activities, which is additional to the value generated by the RAB;

⁵⁷ Frontier Economics, 16 August 2022 "RIIO-ED2 equity cross checks", page 4-5

⁵⁸ OXERA, 22 August 2022, "Market to asset ratios as a cross check for the cost of equity", Section 2

- synergy-related cost savings where multiple assets are held, which could create value outside of the target asset;
- adjustments required due to the network transaction being a part of a wider exchange of assets;
- accrued dividends, which are likely to be embedded into the market capitalisation of a company and need to be adjusted for; and
- a RAB exit multiple as the terminal value.

As OXERA discusses in its report⁵⁹, investors' terminal value assumptions are a key reason why MARs above 1x times are observed. If investors have sticky expectations and believe that MARs will stay approximately at the current level (i.e. above 1x), they can assume a terminal value of above 1x MAR without a need to attribute it to outperformance or the difference between required and allowed return on equity in the upcoming regulatory period. This effect is amplified if the RAB growth is forecast.

With respect to Ofgem's other cross-checks, the TMR estimates produced by investment managers have the primary purpose of providing estimates of future returns to their clients, to ensure that clients are managing their finances prudently. This is mainly a function of their regulatory framework, which have the effect of limiting the maximum rates of return that financial services companies must use in their calculations when providing retail customers with projections of future benefits. With regard to OFTOs, these are operational assets with a very different risk profile compared to the onshore energy networks regulated by RII0-2. In particular, the net cash flows are largely fixed in real terms over the duration of the OFTO tender revenue stream.

We also believe that Ofgem should expand its portfolio of cross-checks. Additional cross-checks could include alternative market-based valuation methods such as price to earnings and enterprise value to EBITDA. Frontier Economics has analysed the profitability performance of UK utilities compared to the FTSE 100 companies against both price to earnings and enterprise value to EBITDA valuation methods⁶⁰. As shown in the graphs below, there is no compelling evidence in this relative valuation analysis that suggests that regulated utilities are outperforming the rest of the market. This is in contrast with the conclusion Ofgem might draw from looking at MAR evidence and assuming that MAR should be one.

Figure 12 - CAPE and Cyclically Adjusted enterprise value/EBITDA, UK networks vs P25, P50 and P75 of CAPE of other FTSE 100 companies



Frontier Economics⁶¹ has also developed two further cross-checks for the cost of equity: Dividend Growth Model (DGM) analysis and long-term profitability comparison. The table below sets out the implied cost of equity ranges derived from the DGM analysis. The values are averages of the cost of equity derived for each working day over the period April 2022 – June 2022. To facilitate comparison with Ofgem's CAPM cost of equity estimate, which is estimated using notional gearing of 60%, we estimated the cost of equity for a notional company with 60% gearing. The analysis utilised the same risk-free rate proposed by Ofgem and assumed a debt beta of zero.

⁵⁹ OXERA, 22 August 2022, "Market to asset ratios and a cross check for the cost of equity", page 4-5

⁶⁰ Frontier Economics, 23 August 2022, "RIIO-ED2 equity cross checks", pages 5-8

⁶¹ Frontier Economics, 23 August 2022, "RIIO-ED2 equity cross checks", pages 8-19

Table 17 - Implied COE ranges from the DGM cross-check

Company	Low case scenario	Base case scenario	High case scenario
Pennon Group	4.6%	5.4%	6.5%
Severn Trent	5.1%	5.9%	7.1%
United Utilities	5.2%	6.0%	7.0%
National Grid	5.7%	6.5%	7.5%
SSE	6.8%	7.9%	9.4%
Range	4.6% to 6.8%	5.4% to 7.9%	6.5% to 9.4%

Note: Figures are in CPIH real terms

Source: Frontier Economics

The cross-check indicates that the cost of equity is higher, across all scenarios and for all companies, than Ofgem's proposed cost of equity of 4.75%. In the most conservative scenario considered, which assumes no real dividend growth in the future, the evidence suggests an implied cost of equity of **between 4.6%-6.8%**, with a **mid-point of 5.7%**.

In the RIIO-ED2 Draft Determinations, Ofgem states that its Step 1 range is not too low, by suggesting that “*cross-checks provide greater support for the lower half of the CAPM-implied range from Step 1*”.⁶² However, the results of the DGM cross-check supports a much higher range than the range considered by Ofgem.

The DGM analysis also shows that the cost of equity for the energy companies is higher than that of water companies. This is in line with our expectations, given that the energy networks' systematic risk exposure is higher than that of water companies due to the structural changes that the energy networks will face in the near future.

To further assess the reasonableness of Ofgem's proposed cost of equity, Frontier Economics has used the DGM model to calculate the implied long-term real dividend growth required for the estimated real cost of equity to be 4.75%.

The findings are shown in the table below. The table shows that, according to the DGM model, the long-term real dividend growth consistent with Ofgem's 4.75% is a **negative real growth** for four out of the five companies considered, of between -0.29% and -1.29%. It would imply a decrease in the RAV or operating profit of the companies in the long term. This is implausible given the expectation of future capital expenditure expected in the water and energy network sectors in the future.

⁶² RIIO-ED2 Draft Determinations, Finance Annex, paragraph 3.82-3.83

Table 18 - Implied long-term real dividend growth required for DGM real COE to be equal to 4.75%

Company	Implied long-term real dividend growth
Penon Group	0.10%
Severn Trent	-0.88%
United Utilities	-0.43%
National Grid	-1.29%
SSE	-0.29%
Range	0.10%- (-)1.29%

Source: Frontier Economics

The DGM evidence shown above is in stark contrast to the conclusion Ofgem is drawing from all of its chosen cross-checks which is that its cross-checks provide “confidence” that the CAPM results are “not too low”. Conversely, our DGM analysis indicates that the 4.75% suggested by Ofgem could indeed be too low.

When setting the cost of equity allowance, Ofgem is effectively setting the allowed level of profitability of the regulated business. Outturn profitability is comparable to the parameter that Ofgem is setting and should be broadly in line with observed average levels of profitability in the long-term. A regime that reduces the profitability of the sector relative to benchmarks and the rest of the market will reduce the attractiveness of the sector in the eyes of investors and may limit the ability of the sector to attract and retain capital at a time when large scale investment is required.

The table below shows the smallest, largest and median CPI-real return on common equity achieved by comparable investment opportunities averaged over 2002 to 2021 (nominal returns are converted to real terms using outturn CPI inflation figures). The benchmark includes UK, EU and US utility indices, four European utilities and five US utilities. The cost of equity allowance range implied by the cross-check spans larger values than implied by Ofgem’s primary methodology, CAPM.

Table 19 - Real return on common equity

	Average 2002 - 2021
Low	6.4%
Median	9.3%
High	19.3%

Source: Frontier Economics analysis of Bloomberg data

Notwithstanding the potential difference in gearing levels of these benchmark companies and the difference between regulated equity and book value equity, these figures show that the allowed return of 4.75% proposed by Ofgem for RIIO-ED2 can safely be regarded as “not too high”. This is in contrast with Ofgem’s proposed set of cross-checks, which all seem to suggest that the cost of equity in real life must be lower.

Additionally, we continue to believe that the ARP-DRP cross check remains a valid cross check for the cost of equity. OXERA has recalculated the ARP-DRP differential and have shown that it decreases from 1.73% in RIIO-ED1 to 0.93% in RIIO-ED2⁶³. This further strengthens the argument that Ofgem should revise its cost of equity upwards.

Step 3 - allowed return on equity consultation questions

FQ14. Do you agree that we should not adjust for expected outperformance when setting baseline allowed returns on equity?

Yes, we agree that Ofgem should not adjust for expected outperformance when setting baseline allowed equity returns.

We remain fundamentally opposed to the principle of adjusting the cost of equity, the incentive to invest, for perceived forecast outperformance. If Ofgem can robustly identify that an element of the price control could lead to excess outperformance. Ofgem should adjust the targets in that element of the price control not the cost of equity. If Ofgem implements an approach of adjusting the cost of equity for expected outperformance we believe it would significantly erode investor confidence and hence increase investor risk. This must ultimately increase the cost of capital which would be an issue for all customers.

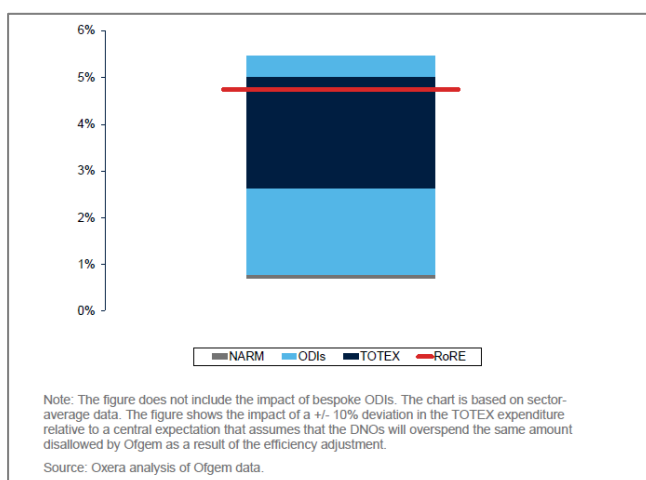
FQ15. Do you believe there is new evidence which would support an adjustment downwards (e.g. expected outperformance) or upwards (e.g. aiming up) that we have not yet considered?

As we have discussed in our response to FQ7, **the asymmetric nature of Ofgem’s proposed incentive framework increases the risk on investors.** We note that, at the CMA PR19 appeal, one of the reasons that the CMA aimed above the midpoint of its cost of equity range was the asymmetric nature of the incentive framework to which the water companies were exposed.

Furthermore, in addition to the asymmetric nature of the incentive framework OXERA illustrates in their paper,⁶⁴ Ofgem’s approach to a range of elements of the RIIO-ED2 price control are asymmetric. This includes totex benchmarking, RPEs, ongoing efficiency, and severe weather. The figure below, taken from the OXERA report, illustrates the scale of this asymmetry⁶⁵.

We also note that the RIIO-GD2/T2 appeals Ofgem recognised that the application of an asymmetric price control framework should result in it setting a cost of equity above the midpoint. At the appeal, the CMA noted that “GEMA

Figure 13 - Illustration of the impact of asymmetric risks on RoRE - post-RAMs



⁶³ OXERA, 25 August 2022, Cost of Equity in RIIO-ED2 Draft Determinations, Table 5.1

⁶⁴ OXERA, 22 August 2022, RIIO-ED2 balance of risks

⁶⁵ OXERA, 22 August 2022, RIIO-ED2 balance of risks, page 3

submitted that it accepted, in principle, that material net asymmetric risk in a price control settlement would warrant a degree of aiming up on the allowed return on equity.”⁶⁶

On this basis we believe that Ofgem should aim above the midpoint of the cost of equity range.

Inflation and WACC consultation questions

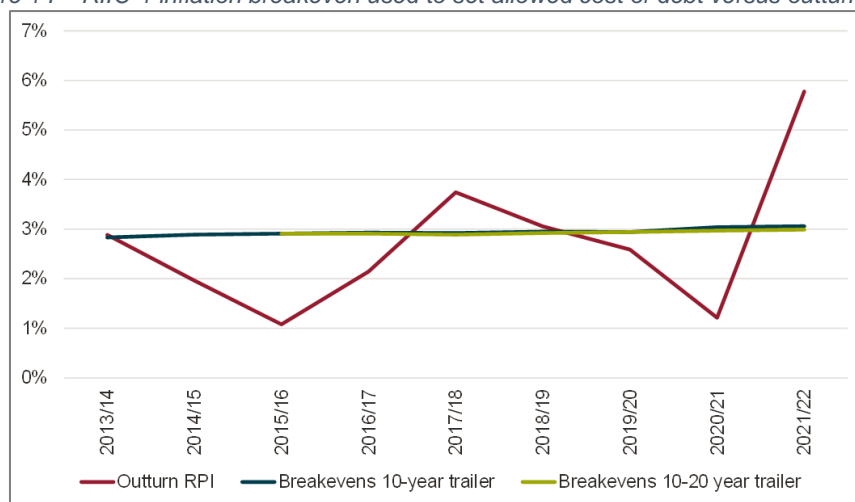
FQ16. Do you think we should adjust our approach to allowed returns (noting our approach to expected inflation for WACC and outturn inflation for RAV as described above) so that outturn inflation does not permit the notional company to generate real equity returns that are materially higher or lower than our cost of equity allowance? What would be the consequences to consumers and DNOs of doing so?

We believe that any changes to the indexation methodology for the RAV would have significant negative consequences. Inflation indexation of the RAV has been a feature of the sector since privatisation and investors in the sector have invested in these assets based on the inflation approach that the framework provides. This feature of the price control framework is a key component of the risk profile of the sector and to change it will undermine investor confidence and hence increase the cost of capital.

Furthermore, we would expect the rating agencies to view such a change negatively. The stability, transparency and predictability of the UK electricity distribution price control framework is a key input into the ratings framework for all of the rating agencies. Such a fundamental change may result in sector downgrade increasing the required credit metrics achieve to Baa1/BBB+, the baseline for notional company. This would require the cost of capital to increase to compensate for this change, which would impact all consumers.

While it is clear that current inflation is at historically high levels, this needs to be viewed in the context of inflation over the longer term. The graph below (from the ENA Frontier Economics report⁶⁷) compares the average outturn inflation and the breakeven inflation for the period 2013/14 to 2021/22, which includes the RIIO-T1/GD1 (the most recently completed price control period). This shows that, despite the uptick in inflation in 2021/22, investors will have been under-remunerated.

Figure 14 – RIIO-1 inflation breakeven used to set allowed cost of debt versus outturn RPI⁶⁸



Note: RIIO-GD1/T1 ran from 2013/14 to 2020/21. RIIO-ED2 ran from 2015/16 and the final year (for which outturn data is not yet available) will be 2022/23. Some networks' allowed cost of debt was based on a 10-year trailing average of the iBoxx index while

⁶⁶ CMA. 28 October 2021, 'Cadent Gas Limited, National Grid Electricity Transmission plc, National Grid Gas plc, Northern Gas Networks Limited, Scottish Hydro Electric Transmission plc, Southern Gas Networks plc and Scotland Gas Networks plc, SP Transmission plc, Wales & West Utilities Limited vs the Gas and Electricity Markets Authority. Final determination. Volume 2B: Joined Grounds B, C and D', paragraph 5.837

⁶⁷ Frontier Economics, 24 August 2022, Inverse inflation exposure

⁶⁸ Frontier calculations of trailing average breakevens using the 2021 AIP cost of debt model here: <https://www.ofgem.gov.uk/publications/riio-ed1-annual-iteration-process-2021>. Outturn RPI as reported by Ofgem in GD2 PCFM for regulatory years here: <https://www.ofgem.gov.uk/publications/gd2-price-control-financial-model>

other networks were allowed a 10-20 year trailing average “trombone”. The chart shows that the breakevens implied by these two trailing average methods were not materially different.

We are unaware of Ofgem raising the issue of the inverse inflation exposure effect during that period to protect equity investors against the downside they were experiencing. The timing of Ofgem’s suggestion to introduce any change in the framework now – when inflation is higher than forecast and therefore currently benefiting investors, but immediately following a period where the leveraging effect worked against investors begs obvious questions about stability and credibility of the regulatory approach over time. In our view, investors could perceive the timing of this change to be opportunistic by Ofgem and would breach the regulatory principles of transparency, consistency and proportionality.

We believe that such a fundamental change to the price control framework must be subject to extensive analysis and consultation. If this proposal is to be taken forward, then it should be considered as part of a future price control process with a full impact assessment undertaken, and not rushed over a period of weeks during the RIIO-ED2 price review.

FQ17. If you believe we should make such an adjustment, what is the best method for making it?

Please refer to our answers to FQ16 and FQ18.

FQ18. If you don’t believe we should make such an adjustment, how should we ensure that the fairness of the price control is maintained to prevent ex post returns from deviating from ex-ante expectations for both consumers and investors?

As we illustrate in our answer to FQ16, if the impact of inflation indexation is considered over the longer term, then there is no indication that the current approach is unfair. **We are concerned that any change introduced without a robust examination of the long-term impact could result in an unfair outcome for both investors and customers.**

A core principle in Ofgem’s approach is that it sets an allowed return for a notional company – and the licensees are then free to choose their own financing strategy which may well differ from the notional firm. Some investors may have chosen to issue predominantly fixed-rate debt in the past and effectively chosen to bear the inflation risk or used it to offset their inflation exposure elsewhere in their wider portfolio. Other investors may have chosen to issue predominantly index-linked debt (or procure derivatives/instruments that have the equivalent effect) and thereby effectively insulated equity returns from the leveraging effect.

Networks’ debt portfolios are built up over time and are generally relatively long-dated. If Ofgem was to change its approach to inflation indexation with no prior signal, Ofgem would be making a decision which effectively imposes an entirely different risk profile on investors to the positions they had believed they were adopting. Any change will require significant time for networks to adapt debt portfolios to re-balance this risk efficiently in light of any new arrangements. This may directly increase the financing cost for many companies which will ultimately result in higher costs for customers.

Ofgem has a duty to protect future customers as well as existing customers. Our concern is that any change to the approach in inflation indexation, to resolve short term issues, without a proper analysis of the long-term impacts, may result in significantly higher costs for future customers which would also be unfair.

Consultation questions on financeability

FQ19. Do you agree with our approach to assessing financeability?

We believe that Ofgem’s assessment of the financeability of the sector is incorrect. Ofgem’s assertion that UK Power Networks would achieve a rating of A3 on the Moody’s scale with an AICR of 1.4x is incorrect. With respect to the latter, 1.4x is the bottom of the Baa1 range and hence we do not agree with Ofgem’s statement that there is sufficient headroom in the metrics.

We also note that Ofgem states that “our assumption on the proportion of the level of index linked debt in the notional company is based on current actual network average proportions of inflation linked debt”⁶⁹. Ofgem has not set out the analysis that supports this statement but the analysis we undertook for our Business Plan indicated that the level of index linked debt in the electricity distribution sector was circa 10% excluding derivatives. The proportion would be higher including inflation linked derivatives but given that Ofgem has excluded the costs associated with these derivatives in setting the cost of debt allowance it would be inconsistent to base the notional company proportion of index linked debt including them.

If the level of index linked debt is set to 10% rather 25% then for EPN and LPN the AICR drops to 1.33x compared to 1.43x in Ofgem’s base case analysis and 1.32x in SPN, compared to 1.42x in Ofgem’s base case analysis. These ratios are significantly below the 1.4x Baa1 threshold of 1.4x. Setting the cost of equity at a level of 5.5% would restore the AICR back to levels stated in Ofgem’s base case.

FQ20. Do you have any evidence that would enable us to improve our calibration of stress test scenarios?

We note that, unlike RIIO-GD2/T2, Ofgem has not published the results of the stress tests it mandated and now regards the -2% RoRE scenario as a highly unlikely outcome. Given that Ofgem has cut our proposed totex by 11% and is also proposing a highly negatively asymmetric incentive framework, we do not regard this as an unlikely scenario. The table below sets out our analysis of the -2% RoRE scenario for each of licence networks for both the base case and the high case.

Table 20 – Adjusted interest cover ratio analysis – Base case totex

Draft Determination base case totex	4.75% Cost of equity -2% RoRE case					Average
	2023/24	2024/25	2025/26	2026/27	2027/28	
EPN	1.08	1.06	1.04	1.03	1.02	1.05
LPN	1.07	1.06	1.04	1.03	1.02	1.05
SPN	1.07	1.05	1.03	1.02	1.01	1.04

Table 21 – Adjusted interest cover ratio analysis – High case totex

Draft Determination high case totex	4.75% Cost of equity -2% RoRE case					Average
	2023/24	2024/25	2025/26	2026/27	2027/28	
EPN	1.07	1.05	1.03	1.01	1.00	1.03
LPN	1.07	1.05	1.03	1.02	1.01	1.04
SPN	1.07	1.05	1.03	1.01	1.00	1.03

This shows that by the midpoint of RIIO-ED2, all three licence networks would be below the Baa3 threshold, particularly under the high case scenario. It should also be remembered that Ofgem adopts a simplified approach to calculating the Moody’s AICR ratio⁷⁰ so the figures derived by the Draft Determinations model will overstate the ratios.

However, if the corrected cost of equity of circa 5.5% is used then these ratios increase to circa 1.17x times which would maintain a minimum of a Baa3 rating under the downside scenario, taking into account that Ofgem’s model overstates the calculated AICR.

⁶⁹ RIIO-ED2 Draft Determinations, Finance annex, paragraph 5.7

⁷⁰ For example, Ofgem do not include adjustments relating to pension deficits, capitalised interest and operating leases which tend to lower the calculated ratios.

Table 22 – Adjusted interest cover ratio analysis – Base case totex

Draft Determination base case totex	5.5% Cost of equity -2% RoRE case					Average
	2023/24	2024/25	2025/26	2026/27	2027/28	
EPN	1.21	1.19	1.17	1.17	1.17	1.18
LPN	1.21	1.19	1.17	1.17	1.17	1.18
SPN	1.21	1.18	1.17	1.16	1.15	1.17

Table 23 – Adjusted interest cover ratio analysis – High case totex

Draft Determination high case totex	5.5% Cost of equity -2% RoRE case					Average
	2023/24	2024/25	2025/26	2026/27	2027/28	
EPN	1.20	1.18	1.16	1.15	1.14	1.17
LPN	1.20	1.18	1.16	1.15	1.14	1.17
SPN	1.20	1.18	1.15	1.15	1.14	1.16

Our view is that Ofgem must ensure that it sets its cost of capital to maintain an investment grade credit rating under the -2% RoRE downside stress test under both the base and high case totex scenarios. It should also be remembered that if the level of index linked debt is set at 10% then all of these ratios would decrease by circa 0.1x.

FQ21. Do you agree with the requirement to provide the Financial Resilience Report within 60 days?

We note that Ofgem's proposal is in line with its approach for both gas distribution and transmission and agree in principle. However, we are concerned that there could be unnecessary duplication. As we outlined in our response to the Sector Specific Methodology Consultation⁷¹, it would be helpful if Ofgem could outline how this additional requirement interacts with the current requirement to prepare, on an annual basis, a statement of financial adequacy.

FQ22. Do you agree with our proposals to make allocation and allowance rates variable values in the RIIO-ED2 PCFM?

Yes, we agree.

FQ23. Do you agree with the proposed additional protections?

Please refer to our responses to FQ24-FQ26.

FQ24. Do you have any views on a materiality threshold for the tax reconciliation?

We agree that a materiality threshold is required.

However, as Ofgem has noted⁷², there remains work to do on the detailed mechanics of the tax review process in terms of aligning the relevant licence conditions and the Price Control Financial Handbook (PCFH). We welcome Ofgem's intention to engage with the companies on the drafting of the licence conditions and PCFH. We believe there should be a reduction in the complexity of the proposed reconciliation statement, reduction in the volume of unnecessary information and simplification of the tax reconciliation to the meaningful variance calculations.

⁷¹ UK Power Networks' response to Ofgem's RIIO-ED2 Sector Specific Methodology Consultation, page 113

⁷² RIIO-ED2 Draft Determinations, Finance Annex, paragraphs 7.34 and 7.35

FQ25. Do you think that the “deadband” used in RIIO-ED1 is an appropriate threshold to use? If not, what would be a more appropriate alternative?

Yes, we agree that the RIIO-ED1 threshold level is appropriate.

FQ26. Do you have any views on our proposals relating to the Tax Trigger and Tax Clawback mechanisms? In particular, do you have any views on a proposed “glide path” for the notional gearing levels used in the tax clawback calculation?

We support the use of the glidepath in relation to the Tax Clawback calculation. We note that Ofgem is planning to undertake a review of the Tax Clawback mechanism⁷³. We would encourage Ofgem to undertake this work sufficiently in advance of the Final Determinations to allow any identified changes to be reflected, where appropriate, in the associated licence conditions and Price Control Framework in a timely manner.

We are comfortable with the Tax Trigger proposals.

FQ27. Do you agree with our proposals for the RAM thresholds and adjustment rates?

We are unclear why Ofgem requires an additional RAM threshold at four percent. Ofgem states, in relation to the three percent RAM threshold, that *“this analysis suggests that there is limited probability that either the upside or downside RAMs will be triggered in the price control”*⁷⁴. The four percent threshold seems superfluous and adds unnecessary complexity in the price control framework.

FQ28. What are your views on the technical implementation of the switch to CPIH as set out in the attached PCFM?

We are comfortable with the proposed methodology.

FQ29. Do you agree with our proposal to set depreciation policy on RAV additions in the RIIO-ED2 period to 45-years straight line, based on the average economic life of the assets?

Yes, we agree.

Consultation question on capitalisation rates

FQ30. Do you agree with our proposal that we should set different capitalisation rates for ex-ante allowances and re-openers and volume drivers?

We do not agree with setting different capitalisation rates for ex-ante allowances, re-openers and volume drivers. The same capitalisation rate should be applied to an area of expenditure whether it is funded under an ex-ante allowance, re-opener or a volume driver.

For example, Ofgem is currently assuming that the capitalisation rate for the secondary reinforcement volume driver is 100%. However, this is linked to its decision that demand flexibility, where the costs are typically treated as opex, is not a valid solution but that it is an acceptable approach for ex-ante expenditure in this area. Such an approach is logically inconsistent. Furthermore, as Ofgem appears to be using sector averages to set the load-related UMs capitalisation rates, it is penalising UK Power Networks. This is because UK Power Networks has significantly more flexibility expenditure in its Business Plan than all the other DNOs. Using a sector average means that UK Power Networks costs are over-capitalised relative to its actual cost make-up, which is incorrect.

This error is also prevalent in Ofgem’s approach to calculating the capitalisation rates for non-variant RPEs. Ofgem has again used a sector average capitalisation which ignores the differences in totex approach between

⁷³ RIIO-ED2 Draft Determinations, Finance Annex, paragraphs 7.24 and 7.25

⁷⁴ RIIO-ED2 Draft Determinations, Finance Annex, paragraph 8.7

companies. For the Final Determinations, Ofgem must calculate individual company RPE capitalisation rates. Furthermore, on variant RPEs, Ofgem has moved costs from the non-variant cost categories to create the variant cost categories. However, for load-related activities such as secondary reinforcement, Ofgem has assumed that these costs are 100% capitalised. Our Business Plan includes flexibility payments for secondary reinforcement and, as we discuss above, these are operating costs. To correct this issue in the Final Determinations, Ofgem must use the same capitalisation rate for both non-variant and variant load-related expenditure.

With respect to UMs, we also disagree with the blanket application of 98% capitalisation factor for all UMs. Ofgem has set out no analysis of how it has come to this figure, and we note that it is materially different to the values that it derived for gas distribution and transmission. With respect to the former, Ofgem set a capitalisation rate of 70% and for the latter it ranged from 70% for gas transmission to 85% for electricity transmission. In coming to its view for these sectors, Ofgem set the UM capitalisation rate based on a range of financeability analysis, stating that this should provide financial support to network companies in the event that higher than anticipated totex (specifically capex) materialises. Given that there's no obvious difference in underlying assumptions (e.g. importance of UM expenditures, notional gearing, credit rating, financeability metrics) between the GDNs and TOs on the one hand and DNOs on the other, it is not evident why Ofgem has carried out financeability analysis to inform the UMs capitalisation rate for the GDNs/TOs but not for the DNOs.

We also note that Ofgem referred to intergenerational equity and the delivery of Net Zero when considering capitalisation rates for GD/T2, but it has not referred to these factors when determining the UMs capitalisation rate for RIIO-ED2. We expect Ofgem to undertake similar analysis for the RIIO-ED2 Final Determination.

The UM percentages also only relate to direct costs. We have proposed that the associated indirect costs must be included for these mechanisms and the impact of these costs must be considered when determining the appropriate capitalisation rate for each uncertainty mechanism.

FQ31. Do you have any evidence that would enable us to improve our estimates of regulatory capitalisation rates?

Please refer to our answer to question FQ30. In addition, we identified that Ofgem has incorrectly mapped BPDT cost categories into PCFM cost categories which resulted in an overstatement of the capitalisation rate. We provided this information as part of the Supplementary Question process and expect that this will need to be corrected for Final Determinations.

FQ32. Do you have any views on the use of forecast RAV opening balances for the start of RIIO-ED2, which will be trued-up following RIIO-ED1 closeout?

We are happy with the proposed approach.

Consultation question on transparency through RIIO-ED2 reporting

FQ33. Do you agree that additional corporate governance reporting described (including on executive director remuneration and dividend policies), will help to improve the legitimacy and transparency of a company's performance under the price control? If not, please outline your views in relation to the rationale provided for these additional requirements, including consumer protection.

In principle, we agree that additional reporting on corporate governance and dividend policies could improve the transparency of a company's performance under the price control. We are happy to work with Ofgem to ensure that the level of reporting is proportionate and meets stakeholders' requirements.

FQ34. What are your views on the proposed consolidation of the revenue RRP and PCFM, or applying a fully dynamic concept of allowed revenue?

We agree that consolidation into a single allowed revenue model, along with the removal of lags will make the calculation of allowed revenue much simpler than the current arrangements. We do, however, have some concerns. The final PCFM model will need considerable development from where it is now, to make it robust, reliable, transparent and hence easy for all stakeholders to use. The dynamic nature of the proposal means that there will not be a point at which the allowed revenue becomes fixed until well after the end of each regulatory year, at least 30 months after tariffs are calculated. This will dilute the link between performance and revenue and also increase the potential for error when forecasting allowed revenue.

FQ35. What are your views on allowing licensees to self-publish the PCFM with their charging statements, rather than relying on an Ofgem publication or direction to determine allowed revenue?

We have some concerns with this proposal. We already publish regular allowed revenue statements, including those within tariff setting, so this would be a simple extension of current practice. We would, however, need very clear and unambiguous guidance. In RIIO-ED1, the final outcome of some incentives and uncertainty mechanisms has only been achieved with direct input from Ofgem and this process would need to be eliminated if we are to self-publish. Unless there is significant simplification of the PCFM it would also be sensible to publish a stakeholder summary document for use by third parties to aid transparency.

FQ36. What are your views on having a best endeavours obligation for charge setting: "The licensee must, when setting Network Charges, use its best endeavours to ensure that Recovered Revenue equals Allowed Revenue"?

We disagree with Ofgem's proposal that the obligation should remain a "reasonable-endeavours" obligation. Please refer to Appendix 1 where we explain our views.

In summary, we think that Ofgem made a conscious decision to require DNOs to use reasonable endeavours when setting network charges for RIIO-ED1 and has not adequately justified its proposal to impose a more onerous obligation.

Ofgem's argument for making this change seems to rely on three pieces of logic:

- That the obligation is arguably "*the most fundamental obligation*" in the price control;
- That greater responsibility is appropriate given the expectation that licensees will self-publish the value of allowed revenue; and
- That making the change would bring electricity distribution into line with other sectors.

These arguments are not sufficient, individually or collectively, to justify the proposed change. Furthermore, Ofgem has failed to recognise that it would be inconsistent to increase this obligation at the same time as making other changes to the price control package, such as removing the two-year lag that applies to many aspects of the price control as they flow through to Allowed Revenues.

Additionally, while Ofgem has recognised that the introduction of such an obligation would cause DNOs to incur additional costs in meeting a more stringent obligation, Ofgem has failed to fund DNOs to undertake those activities.

We cover these three points in more detail in Appendix 1.

FQ37. What are your views on applying a single time value of money to all prior year adjustments, based on nominal WACC?

We support this proposal. Given that Ofgem is proposing to remove lags and require companies to forecast revenue each year, the only timing adjustment would be the K term. On this basis a single adjustment would make sense rather than trying to decompose the source of the error and apply different approaches to it. **However, we are not sure why it is the nominal rather than the real WACC as our working assumption is that all revenue adjustments will be in 2020/21 prices and then multiplied by inflation.**

FQ38. What are your views on our proposed approach to using forecasts within RIIO-ED2?

We agree that forecasting actual inputs rather than waiting for historical trued up values makes the process simpler, but we believe this approach will lead to increased forecasting error. Many of the forecast components are driven by precise formulae to which our best view of inputs can be applied. However, some items, which may in the past have been decided by Ofgem and may contain a degree of discretion, will require comprehensive and unambiguous guidance from Ofgem to facilitate accurate forecasts. Even then the extended forecast period will reduce accuracy.

FQ39. What are your views on the proposed charging penalty mechanism?

The splitting of the forecast penalty mechanism into two components is sensible and we agree that the threshold of six percent is reasonable, based on recent experience. We believe that Ofgem's intention to keep the discretion to waive penalty interest is necessary. The push towards Net Zero, along with general social and economic uncertainty and an increasingly complex tariff structure, will make forecasting more difficult over the coming years.

FQ40. What are your views on the proposed revenue forecasting penalty mechanism?

The removal of inflation from this mechanism is a necessary step, as is demonstrated by current events. We also agree with Ofgem's intention to retain the ability to waive penalty interest where appropriate. However, we still believe that changes to the allowed revenue calculation, in particular the removal of the two-year lags and Modification of Base Revenue (MOD) term adjustment, will increase the difficulty in preparing accurate forecasts at the time tariffs are set. These forecasts will then be exposed to change over the next 30 months. It should also be noted that, by the time we have a final version of the RIIO-ED2 licence, PCFM models and RIGS, we will have already published two sets of tariffs and be working on the publication of the third.

FQ41. What are your views on removing lags from incentives?

We have some concerns with the proposed approach which we would ask Ofgem to address in its Final Determinations.

In principle, we can see benefits from removing incentive lags as it allows better alignment between in-year performance and revenue earned and reduces complexity, thus aiding transparency.

However, the link between performance and revenue will not be perfect as tariffs will be set 30 months before performance for any year is out turned. In addition, the transition to this policy may require one-off arrangements. The 2023/24 revenue has already been calculated and 2024/25 revenue will have to be calculated at the same time as the Final Determinations are being published. There may be an issue associated with the truing-up of revenues from the first two years of RIIO-ED2, as this will impact the overall 2025/26 revenues. It may be beneficial once the impact of this is more certain, and if it is determined to be material, to spread it over the remaining years of RIIO-ED2 in an NPV neutral manner. Ofgem adopted a similar approach in relation to catering for the impact of the DPCR4 losses closeout.

FQ42. What is your view on using RoRE as a general baseline for describing ODI caps, rather than base revenue?

In principle, we have no issues with ODI caps being set relative to RoRE, as long as the equivalent overall financial value is maintained (as per paragraph 10.175 of the Finance Annex). However, we are concerned that Ofgem's approach does not recognise the overall financial incentive in key areas, such as reliability and customer service. Ofgem needs to appropriately reflect the value customers place on these areas. This is particularly true in an environment where electricity will become essential for both transport and heating. This is addressed further in our responses to Core questions on the calibration of each key incentive scheme.

FQ43. What is your view on fixing the potential £m 20/21 value of incentives using one number for all years, based on a forecast of RIIO-ED2 at Final Determinations (an approach similar to RIIO-ED1)?

We agree with using a fixed value, in 20/21 prices, to fix the value of the incentives.

FQ44. What is your view on the method of calibrating incentive caps in RoRE terms, or the overall proposed incentive caps?

In principle, we agree that using the RoRE to calibrate incentive caps is sensible. However, the sector average RoRE factor that Ofgem is using is heavily influenced by the WPD networks (which is evidenced by the fact that all four of the networks plus SP Manweb sit below the average with the remaining nine DNOs above the average). Therefore we think that Ofgem should use the industry median of 0.41% rather than the average of 0.39%.

FQ45. What are your views on our proposal to remove the Bad Debt terms from the pass-through licence condition?

We can see no adverse effects from bad debt being included in the correction factor rather than as a pass-through cost.

FQ46. Should Ofgem allow proposals to re-allocate or re-profile revenue throughout the RIIO-ED2 period and what profiles could be considered in the customers' interest?

We remain of the view that it is appropriate to allow companies to profile revenue across the price control period. Ofgem has allowed revenue profiling in previous price controls and has used it itself to smooth customer bill impacts. The profiling of revenue is net present value neutral and as it is all undertaken within the specific price control period there are no inter-generational issues.

The profiling that we proposed in our Business Plan reduced revenues in the early years of RIIO-ED2 and increased them towards the end. From a customer perspective this lowered the bill at the start of the RIIO-ED2 period. Given the current cost-of-living crisis we believe that this is in customers' interests. The table below compares the unprofiled customer bill profile from Ofgem's Draft Determinations with our calculation of the bill profile using the revenue profiling we proposed as part of our original Business Plan submission. This illustrates that our proposal would produce a bill reduction of between five percent to seven percent in the first two years of RIIO-ED2 compared to Ofgem's Draft Determinations proposal.

Table 24 - Unprofiled vs profiled bill comparison (£ per domestic customer, 2020/21 prices)

Ofgem proposed bill profile	31 Mar 2024	31 Mar 2025	31 Mar 2026	31 Mar 2027	31 Mar 2028
EPN	83	83	80	78	77
LPN	61	62	60	58	56
SPN	98	101	91	89	87

UKPN revised profile	31 Mar 2024	31 Mar 2025	31 Mar 2026	31 Mar 2027	31 Mar 2028
EPN	79	79	82	82	81
LPN	57	57	61	61	61
SPN	93	95	93	94	92

% Difference	31 Mar 2024	31 Mar 2025	31 Mar 2026	31 Mar 2027	31 Mar 2028
EPN	-6%	-5%	2%	4%	5%
LPN	-7%	-7%	2%	6%	8%
SPN	-5%	-7%	2%	5%	6%

The ability to profile revenue is also positive from a company perspective. Based on the historic approach to revenue profiling, investors and the market expect an initial decrease in a company's revenue with a growing profile from that point. Furthermore, it allows the smoothing of the profile of a number of credit metrics, which is also beneficial from an investor perspective.

QUESTIONS IN THE DRAFT DETERMINATIONS – UK POWER NETWORKS ANNEX

UKPN-Q1. What are your views on the company specific parameters we have proposed for the common outputs that we have set out above?

We agree with the proposed company specific parameters.

UKPN-Q2. What are your views on our proposals for UKPN's bespoke ODIs?

We accept Ofgem's position on our proposed bespoke ODIs, although we are disappointed by it. We summarise our views below.

Table 25 - Summary of our views on bespoke ODIs

Bespoke ODI proposal	Our position	Commentary
Short Interruptions	Accept	We are disappointed by Ofgem's position. More generally, we do not understand Ofgem's reasons for delaying the introduction of a minimum standard for short interruptions. In response to Ofgem's position in paragraph 6.100 of the Core Methodology, we consider that research on the appropriate value of the payment to customers could be conducted and that payment should be automatic (contrary to Ofgem's suggestion that customers would need to claim payment). In addition, we consider that, if a minimal standard were implemented in RIIO-ED3, we should not be disadvantaged in RIIO-ED3 target setting having already committed to an improvement.
Reporting repeat power cuts	Accept	We are disappointed by Ofgem's position. We think that our proposal would have provided better visibility of performance for a wider range of customers and would have been a steppingstone to introduce a metric for RIIO-ED3.
Reporting Total Time not Supplied	Accept	We are disappointed by Ofgem's position. We think that our proposal would have provided better visibility of performance for a wider range of customers and would have been a steppingstone to introduce a metric for RIIO-ED3.
Collaborative Street works	Agree	We agree with Ofgem's position. Please note our views in our response to UKPN-Q3 below.

UKPN-Q3. What are your views on our proposal to implement a collaborative streetworks ODI-F as set out above?

We welcome Ofgem's inclusion of a collaborative streetworks ODI-F. We also note that Ofgem has clarified through the Supplementary Question process that the incentive extends to all DNOs in London.

Our only concern is about the cap, currently set at 0.5% of base revenue pre-TIM. We think Ofgem should apply the cap post-TIM to allow us to carry out more projects. Ofgem notes that each completed collaboration project has a value of £305k. As shown on the table below, if the cap is applied pre-TIM, we can conduct 16 projects per year. If the cap were applied post-TIM, only £152.5k per project would count towards the cap – which also corresponds to the amount we have effectively received. We could then undertake up to 34 projects per year. Independent research has demonstrated that, by collaborating on streetworks projects, utilities can significantly reduce disruption in London, which translates into financial and social benefits. We therefore see no reason to constrain our capacity to participate in the GLA collaborative streetworks framework.

In addition, Ofgem suggests that at least 40 projects must be completed by the end of RIIO-ED2. We expect that most projects will take place in LPN as it covers most of London. The table below shows that, if the cap is applied pre-TIM we would only be rewarded for undertaking up to 20 projects in LPN during RIIO-ED2. The cap is therefore not aligned with the fact we expect most of our activity on collaborative streetworks to be in LPN.

Table 26 - Comparison of number of projects allowed pre- and post-TIM given 0.5% annual cap on base revenue

DNO	Annual maximum incentive (0.5% of base revenue)	Annual number of projects before reaching the cap (pre-TIM)	Annual number of projects before reaching the cap (post-TIM)
LPN	£1.5m	4	9
SPN	£1.6m	5	10
EPN	£2.4m	7	15
UKPN	£5.5m	16	34

UKPN-Q4. What are our views on our proposals for UKPN's bespoke PCDs?

Please refer to our response to UKPN-Q5 below.

UKPN-Q5. What are your views on our proposal to fund investment to release capacity in off-gas grid areas ahead of need via a PCD as set out above?

In principle, we agree with Ofgem's proposal to fund our proposed CVP as a PCD, but Ofgem's approach will underfund our plans. Our proposal had two dependent parts. The first is a programme of capacity release ahead of need to enable - by the end of 2028, 241,687⁷⁵ off-gas grid customers will have the capacity to decarbonise their heating and transport. The second element is a programme of coordinated engagement, education, advice and referrals to off-gas grid communities to promote the uptake of energy efficiency and heat electrification. Ofgem has only funded the first element of our proposal and excluded the £1.5 million of costs associated with the energy efficiency advice and support service.

This is problematic because the funding we requested was based on our estimation of what we need to spend, to unlock the required capacity. As Ofgem has disallowed this part of our proposal, capacity requirements, and therefore the associated network investment, will be higher than we anticipated in our proposal. Ofgem should either increase our allowance to enable us to deliver the required capacity or accept that the delivered capacity will be lower and therefore fewer customers will be able to transition to electric heating.

Moreover, it is not clear why Ofgem has ruled out funding for us, when another DNO has had a similar scheme accepted with reward under the CVP methodology. For example, we compare initiatives below and Ofgem's position against each in the table below.

⁷⁵ It is important to re-emphasise the 241,687 customers with available capacity includes those off-gas grid customers that could transition to electric heating through existing capacity or other investment drivers such as wider reinforcement work or the PCB replacement programme. We propose the funding of this PCD is only associated with the network investment linked specifically to allow off-gas grid customers to decarbonise, to avoid double funding. More details are provided in our response to UKPN-Q6.

Table 27 - Comparison of UKPN and another DNO's CVP on energy efficiency advice

DNO	Scheme	Description	Ofgem Decision
UKPN	Partner with trusted intermediaries to deliver energy efficiency advice and measures to off-gas communities	Part of our CVP, this £1.5 million scheme works with partners to deliver behavioural and energy efficiency measures.	Rejected
Another DNO	Energy savings and energy efficiency measures	Part of the CVP 5 (£7.1 million total) - Promoting a range of interventions such as tariff switching, application support for energy efficiency schemes and installation of smart meters.	Accepted with £3.6 million reward

To allow Ofgem the opportunity to give full consideration to our proposal, we are happy to provide additional evidence in support of our plans. Ofgem stated that there was “*limited justification and evidence of the benefits*” the collaborative work would provide, including from an innovation project – CommuniHeat – which had yet to conclude⁷⁶. CommuniHeat has now concluded. We have provided additional information as appendices, which are outlined below:

- **CommuniHeat Home Action Plan:** An example of the tailored advice provided to customers in off-gas grid communities to facilitate the transition to decarbonised heating; and
- **CommuniHeat Draft Report:** An overview of the innovation project, including the approach, methodology, results and benefits discovered. Please note this is a draft report only, a final, public version will be released in the coming months.

We consider it would be in the interests of customers if Ofgem were to reconsider its decision not to allow the funding associated with the collaborative support and energy efficiency advice as it offers the lowest cost and most efficient route to enabling these customers to transition to decarbonised heating. We would ask that Ofgem considers this additional evidence in reaching its Final Determinations.

UKPN-Q6. Which metrics could be used for holding UKPN to account for delivery of its off-gas grid proposal via a PCD and protecting consumers by clawing back allowances?

Notwithstanding our views on the funding of the PCD, we propose a mechanistic measurement where the output is defined as the number of customers enabled to decarbonise their heating. We think our proposed approach has three key advantages:

- The proposed output definition is directly linked to the outcome the PCD seeks to achieve;
- A mechanistic approach will provide better visibility of the progress made while minimising the administrative burden; and
- The proposed output definition is likely to be more reliable than a PCD based on volumes of work which remain uncertain. While we have based our estimates of our work on the best available evidence, it is likely the specific volumes of assets installed on the network (e.g. numbers of transformers, kilometres of cables and overhead lines etc) will vary as more detailed studies and engineering optioneering are undertaken, along with other external changes to the network (i.e. other connections and impact of energy efficiency and customer behaviour).

The table below provides more detail on our proposal, which we have also discussed with Ofgem during bilateral engagement.

⁷⁶ RIIO-ED2 Draft Determinations, UKPN annex, paragraph 2.36

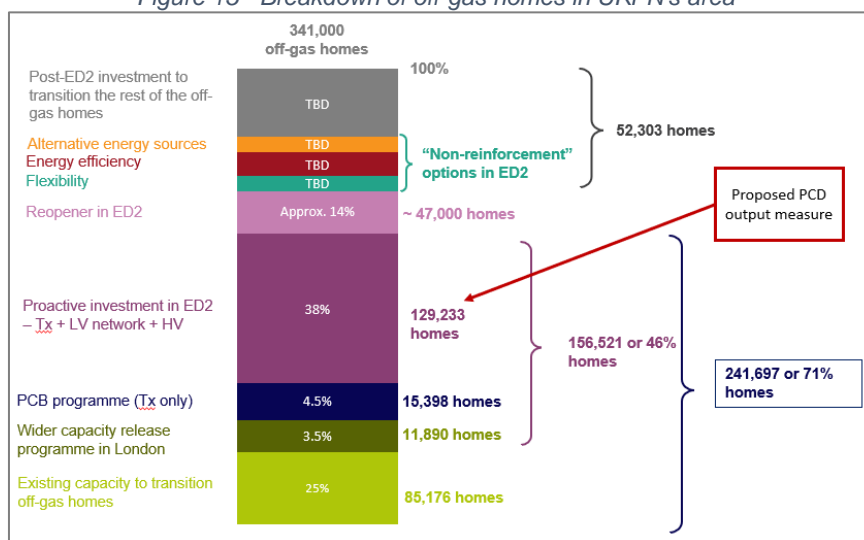
Table 28 - Proposed PCD measurement

Definition of output	129,233* number of customers with the capacity to decarbonise their heating
Key requirements	Customers must be or have previously been off-gas grid and their electricity supply must be capable end to end to provide a connection for a heat pump and EV (up to and including the cut out) as a result of our dedicated off-gas grid investment.
Delivery date	31 March 2028
Allowance	£75.25 million*
PCD type	Mechanistic PCD, where the number of customers with available capacity is recorded on a yearly basis as part of the RRP annual submissions. Unit cost = allowance/output.
Secondary reportable measures	Number of assets installed. We also propose to include within annual reporting a summary of the work we have delivered, including reporting on the wider number of off-gas grid customers that have the available capacity to transition to electric heating, such as through existing capacity or other reinforcement drivers. This will provide an insight into specific achievements and challenges within the year, but it should not lead to requiring a formal review and response as an evaluative PCD would.

* Subject to our views on Ofgem's decision on community collaboration and energy efficiency support and its impact on customer numbers and/or network investment. Please refer to our response to UKPN-Q5.

Our proposed output, 129,233 customers, is based on the number of customers who would be able to decarbonise their heating as a result of our proposed off-gas grid programme, rather than those who already have the capacity or those enabled by other activities for example in flexibility or energy efficiency. The figure below provides a breakdown of off-gas grid customers in our area and captures those customers we think should be included in the PCD. Further detail is provided in our Off-Gas Grid EJP-NP-102.

Figure 15 - Breakdown of off-gas homes in UKPN's area⁷⁷



⁷⁷ For the 52,303 homes marked as TBD in the figure, the substations that supply electricity to these customers also supply on-gas homes and there is much less certainty on the decarbonisation pathway for these customers. For example, the magnitude

Furthermore, we want to clarify two points which Ofgem raised during bilateral engagement:

- **Treatment of business customers within our off-gas grid strategic investment proposal.** If the business is a single-phase supply with the same network attributes as a domestic supply, we would count them towards the output as the customer is likely to be a SME who could transition to decarbonised heating as a result of our upstream investment. Any business on 3-phase would not be counted towards the output; and
- **Avoiding double counting of other load investment.** As mentioned above, it is important that the PCD only captures those customers who were able to decarbonise their heating *as a result of our off-gas grid programme*. To avoid double funding of investments or double counting of customers able to transition, we have proposed to only include those customers that have been enabled through the investment demarcated via the off-gas grid programme, i.e. 129,233 homes.

This demarcation is enabled by the list of interventions that are part of this proposal, these are all HV and LV interventions and do not include Primary Substation interventions. Within our wider response to the Draft Determinations we have included a map, titled '*Proposed Off-Gas Grid Investment Map*', that outlines the investments at HV and LV from the off-gas proposal and that of those anticipated under load. Additional load investments will be recorded via the secondary and primary load-related volume drivers.

We believe that the information above and supporting information should provide enough detail for Ofgem to define a PCD for this investment. We remain available for further dialogue as required.

UKPN-Q7. What are your views on our proposal for UKPN's CVPs?

Consumer Vulnerability Fuel Poverty support programme

We disagree with Ofgem's draft determination on our proposed Fuel Poverty Programme. We make three observations.

First, Ofgem's refusal to fund our Fuel Poverty Programme is in complete disconnect with the current context. At a time when one in three households is expected to fall into fuel poverty following October' price cap increase – with further increases expected in January and April, according to the National Energy Action⁷⁸, we believe Ofgem should support DNOs in their effort to provide fuel poverty support rather than hinder them.

Second, Ofgem's position on our CVP creates anomalies which should be corrected:

- Ofgem's position puts us at odds with other DNOs which received funding for fuel poverty support through their ex-ante allowance. This is summarised in the table below. We require equivalent treatment to other DNOs to ensure that there is no discrimination and Ofgem is treating all of the DNOs fairly and consistently. There is no reason why our customers should not have access to fuel poverty support like customers from other DNOs would; and
- We are still being held to account for delivery of the full fuel poverty programme through the Vulnerability ODI-(F). Our targets reflect the full programme with both customer and shareholder funding. We should be appropriately funded to meet our targets.

Third, Ofgem's concerns about the proposed scale of our fuel poverty programme are ill-founded. Ofgem states that "*while we recognise the need for a scale up in fuel poverty support and the impact of the cost-of-living crisis, we consider that investing a further £9 million of consumers' money into a scheme for an additional 100,000 customers to be supported is not appropriate. Accepting this would push UKPN's fuel poverty support beyond that of any other DNO for RIIO-ED2 contributing to a disparity of support across DNO regions*"⁷⁹. The scale of our effort should not be assessed in absolute terms but relative to our customer base, which is larger than that of other

of homes that could have capacity enabled via other means such as energy efficiency, flexibility and alternative energy sources is much less certain. This is why at this stage we have not defined the splits of customers across the different stacks. As a result, we believe investing at this stage to allow 100% of all off-gas grid customers to electrify does not deliver best value for customers.

⁷⁸ Utility Week, 21/07/2022, "One in three households expected to fall into fuel poverty".

⁷⁹ RIIO-ED2 Draft Determinations, UKPN Annex, paragraph 2.42

DNOs. The table below (last column) shows that our programme proposes to help 24 customers per 1000 customers connected to our network, which is in line with other DNOs.

Ofgem should accept our Fuel Poverty Programme CVP without reward and include £9 million in our ex-ante allowance to ensure the programme is appropriately funded and on an equivalent basis to the rest of the country.

Table 29 - Comparison of Fuel Poverty programme funding

	Strategy cost*	Year 2 target (NPV, £m)	Year 5 target (NPV, £m)	Customers reached (from Strategies)	Customers supported per 1,000 customers connected
UKPN	£0m**	£3.7m	£9.3m	100,000 (shareholder funding)/100,000 (customer funding)	24
WPD	£9.7m	£21.3m	£51m	113,000 customers	14
SPEN	£9.4m	£3.2m	£9.7m	100,000 customers	28
ENWL	£10m	£20m	£61m	125,000 customers	52
SSEN	£4m***	£2.6m	£15.7m	50,000 households, 114,000 customers	29
NPG	£3m	£6.8m	£16.4m	100,000 customers	25

*These figures are as presented in Vulnerability Strategies for Fuel Poverty programmes

**This is the perceived outcome of the Ofgem position, our strategy had £9m customer funding through the CVP and £9m shareholder funding through the UK Power Networks Trust. We are being held to equivalent targets but with no baseline funding

***Plus £1.2m additional activity across Fuel Poverty and LCT, plus £1m for partnership fund, also note £2.5m shareholder fund focused on Net Zero

Whole system CVP for public charging

Although we are disappointed by Ofgem's position, we accept it.

Whole system CVP for off-gas grid

We provided views on Ofgem's position in our responses to UKPN-Q5 and UKPN-Q6 above.

UKPN-Q8. What are your views on our proposals for the outcome of Stages 3 and 4 of the BPI for UKPN?

We were extremely surprised and disappointed by Ofgem's proposed outcome for stages 3 and 4 of the BPI – both for UK Power Networks and across the rest of the DNOs. We followed Ofgem's Business Plan Guidance and the ethos of having an agile plan which could flex to changing scenarios, whilst minimising uncertain costs falling on customers upfront. Ofgem's own Customer Challenge Group held our plan up as clearly the best overall plan, with almost more green ratings than the rest of the industry combined. Subsequently Ofgem's own assessment of plans has identified omissions in the plans from a number of DNOs, which have gone unpunished. In addition, Ofgem's cost benchmarking, with its mixture of totex and disaggregated models, places UK Power Networks as the "most efficient" DNO, but due to the various flaws in Ofgem's benchmarking, plus the choice of an efficiency catch-up which exceeds the level of the most efficient DNO (UK Power Networks), we find there is no upside in the stage 4 BPI assessment.

We have seen no reflection of the benefits we have provided by keeping actual costs down to customers in RIIO-ED1 and minimising cost increases for RIIO-ED2. Had we followed an equivalent approach to that of the wider industry the costs to our customers would be higher, and the industry benchmarks would also increase – resulting in higher costs to GB customers. It is incomprehensible that the DNO forecasting an average cost per customer of £112 (post-ongoing efficiency and pre-RPEs) receives no stage 4 reward, when the industry average cost per customer excluding UK Power Networks is moving up by c.30% from £131 to £170. The failure to place any value on UK Power Networks taking a customer orientated approach to the Business Plan Incentive signals that for future RIIO price controls there is zero merit in putting forward a stretching business plan.

The Draft Determination outcome, with zero penalties and zero rewards for the BPI stands in stark contrast to the equivalent outcome at RIIO-ED1. Making use of the Fast-track and Slow-track processes Ofgem ultimately provided a Fast-track reward of over £175 million and imposed penalties via the IQI of up to 0.4% p.a. of RoRE, which for UK Power Networks will be in the region of £58 million over the RIIO-ED1 period.

We are encouraged by our recent discussions with Ofgem's team who recognise that the proposed application of RIIO-ED2 regulatory tools do not differentiate between high performers and bad performers. As Ofgem's team has acknowledged, this is not in line with Ofgem's Business Plan Guidance. To remedy this, Ofgem should:

- Make stage 1 of the BPI assessment meaningful and enforce the minimum requirements outlined in the Business Plan Guidance. We detail our views on the stage 1 assessment in our response to Q7;
- Apply Ofgem's assessment criteria of CVPs fairly across DNOs, to bring substance to the stage 2 and CVP as a regulatory tool. We detail our views on Ofgem's assessment of our proposed CVPs in our responses to UKPN-Q7; and
- Effectively penalise DNOs who have submitted unnecessarily high costs and reward those DNOs with ambitious plans as part of the stage 3 and stage 4 assessments.

UKPN-Q9. What are your views on our proposals for UKPN's bespoke UMs?

We are concerned by Ofgem's rejection of our bespoke UMs. We present our views below on diversions, accelerating London's decarbonisation, and LRE re-openers.

1. We disagree with Ofgem's rejection of our proposed UM for diversions

We disagree with Ofgem's assertion that DNOs can manage the forecasting risk associated with diversions. Our Business Plan submission covering diversion works was predicated on a UM being included by Ofgem in this area. Ofgem itself notes that "*wayleaves and diversions are inherently subject to a high degree of uncertainty*"⁸⁰ We therefore remain supportive of including a UM on diversions and wayleaves, but in the absence of one being included, we would require Ofgem to move the associated £181 million of additional expenditure flagged in our Business Plan into our baseline allowances. Doing so would help to ensure consistent treatment between DNOs.

In addition, Ofgem's proposal creates a number of inconsistencies:

- We note that UM for diversions has been introduced in RIIO-GD2;
- A UM was allowed in Scotland but not in England & Wales;
- Rail and highways diversion activities are managed through a UM. Please our response to Core-Q78; and
- It is generally accepted that DNOs should be funded to manage circumstances beyond their control. We do not understand why diversions should be an exception.

We therefore believe there is a strong case for Ofgem to include a common diversions UM, which would enable DNOs to submit a request for additional allowances in year 2 of RIIO-ED2.

⁸⁰ RIIO-ED2 Draft Determinations, WPD Annex, Table 28 - row for EJP016

2. We disagree with Ofgem's rejection of our proposed Accelerating London's Decarbonisation UM

Ofgem notes that the LRE UMs and/or Net Zero re-opener negate the need for a specific re-opener to enable the GLA to meet its target of delivering Net Zero at a quicker pace than the UK's 2050 target.

As covered in our response to Core-Q6, we do not yet have sufficient confidence that the Net Zero re-opener process will enable us to make strategic investments across our London networks that would cater to the GLA's needs. Currently there is no clarity around how we would trigger the Net Zero re-opener in terms of the evidence we would be required to provide, the time any review would take and what exactly the role of the Net Zero Advisory Group is. As there could be a need to undertake significant network upgrades across all voltages to support a rapid transition, we seek greater assurances that the price control will not be a blocker should these network upgrades be justified.

3. We have strong concerns about the LRE UMs

Please refer to our responses to Core-Q4 to Core-Q5 for further detail.

Whilst we agree with the development of the common LRE UMs, there are fundamental issues across these, which we summarise below alongside our proposed solutions:

- The volume drivers exclude flexibility, which will encourage DNOs to prefer capital-based solutions;
- The 98% capitalisation rate of volume drivers is not reflective of the combination of indirect, flex and direct work that will be undertaken and is misaligned to ex-ante arrangements. It also disadvantages DNOs who have submitted ambitious plans; and
- The LRE UMs do not fund closely associated indirect and business support costs, effectively under-funding DNOs for additional LRE.

UKPN-Q10. What are your views on the level of proposed NIA funding for UKPN?

The level of proposed funding is stretching and acceptable to UK Power Networks. UK Power Networks set this level of funding as a result of stakeholder engagement, based upon spend on the RIIO-ED2 themes, in RIIO-ED1, demonstrating a mature innovation culture, which is less dependent on stimulus.

Appendix 1: Detailed response to FQ36

FQ36. What are your views on having a best endeavours obligation for charge setting: "The licensee must, when setting Network Charges, use its best endeavours to ensure that Recovered Revenue equals Allowed Revenue"?

We disagree with Ofgem's proposal: the obligation should remain a "reasonable endeavours" obligation

Ofgem made a conscious decision to require DNOs to use reasonable endeavours when setting network charges for RIIO-ED1 and has not adequately justified its proposal to impose a more onerous obligation.

Ofgem's argument for making this change seems to rely on three pieces of logic:

- That the obligation is arguably "*the most fundamental obligation*" in the price control;
- That greater responsibility is appropriate given the expectation that licensees will self-publish the value of allowed revenue; and
- That making the change would bring electricity distribution into line with other sectors.

These arguments are not sufficient, individually or collectively, to justify the proposed change. Furthermore, Ofgem has failed to recognise that it would be inconsistent to increase this obligation at the same time as making other changes to the price control package, such as removing the two-year lag that applies to many aspects of the price control as they flow through to Allowed Revenues.

Additionally, while Ofgem has recognised that the introduction of such an obligation would cause DNOs to incur additional costs in meeting a more stringent obligation, Ofgem has failed to fund DNOs to undertake those activities.

We consider each of Ofgem's arguments below.

1. Ofgem's argument that a change is required to reflect "*the most fundamental obligation in the price control*" fails to recognise (a) the increasing costs to be funded by consumers without additional benefit or (b) the safeguards that are already incorporated into the price control to protect customers from any deviation between Allowed Revenue and Recovered Revenue

DNOs take their obligations in respect of setting network charges seriously and recognise the importance of taking appropriate care in setting network charges. However, there is a balance to be struck between the effort expended (and costs incurred) in chasing increased accuracy of network charges and the extent to which incremental efforts actually result in improvements that benefit customers.

In order to set network charges so that Recovered Revenue equals Allowed Revenue, DNOs have to forecast the level of Allowed Revenue and the amount of electricity that will be used by different customer groups during the relevant Regulatory Year. The level of uncertainty in both components is already considerable, and is expected to increase for RIIO-ED2.

We remain concerned that the costs incurred in meeting the more stringent obligation may not be in customers' interests and may run counter to other policies that customers value, especially the requirement to give 15 months' notice of changes to network charges.

Any efforts to further improve the accuracy of forecasting of network charges will only ever make marginal improvements. The costs incurred to do so may be considerable, and, in any case, any marginal improvements in accuracy will be dwarfed by the general uncertainty associated with forecasting many material aspects of both Allowed and Recovered Revenue.

There are other existing safeguards in place to protect customers from the adverse effect of network charges being set in a way that does not lead to Recovered Revenues matching Allowed Revenue. These safeguards include under- and over-recovery mechanisms that ensure that customers ultimately pay the appropriate amount, and penalty interest calculations that apply to any material deviations between Allowed Revenue and Recovered Revenue. These are far more effective safeguards than Ofgem's proposal to change the level of obligation.

1.1. Ofgem has failed to provide examples that justify increasing the obligation, and has not answered the examples provided by DNOs that demonstrate the additional costs that would be incurred in chasing very marginal improvements in accuracy of network charges

The current obligation to use reasonable endeavours is already a strongly phrased obligation. Ofgem has also not yet provided any examples of shortcomings with the current DNO processes that merit any increase in obligation standard.

DNOs accept that there have been some instances where DNOs' Recovered Revenues have not matched Allowed Revenue during RIIO-ED1. However, these have largely arisen due to significant exogenous factors such as the effect of the COVID-19 pandemic on consumption by different customer groups, the changes in Allowed Revenue due to supplier of last resort obligations and the change in customer behaviour following the recent material increases in energy prices. These simply would not have been forecast in advance under any obligation standard, and especially at 15 months' notice.

While some components of Allowed Revenue and Recovered Revenue can be forecast with some accuracy at the time of setting network charges, many simply cannot. Those factors that can be readily and accurately forecast will already be forecast with appropriate accuracy under the current reasonable endeavours requirement.

In contrast to Ofgem's approach, DNOs have provided Ofgem with specific examples of activities that could be required under a best endeavours obligation. Most have not been addressed in Ofgem's justification for proposing a best endeavours obligation.

We do not repeat all of the examples previously provided in this response, but highlight a few to illustrate the issues. It is simply illogical to impose such an increased burden in the face of clear evidence that increasing the obligation would increase costs for very limited, if any, customer benefit.

1.1.1. Example: Uncertain costs – uncertainty mechanisms

Ofgem proposes to set baseline totex allowances "*only where [it is] satisfied on the need for and certainty of the proposed work*"⁸¹. Totex allowances for all activities where uncertainty remains will be set via uncertainty mechanisms.

In setting network charges, DNOs need to estimate future totex allowances associated with these uncertainty mechanisms without knowing actual performance or need and ahead of any re-opener submission or Ofgem decision. Ofgem acknowledges that "*Forecasting costs and outputs with confidence for the duration of a price control is challenging*"⁸². These uncertainty mechanisms may amend totex allowances for any year of the price control. This is different to RIIO-ED1 where the decision would result in an amended MOD term that would apply to future Allowed Revenues.

Any move to a best endeavours standard would require considerably more expenditure by DNOs in predicting acknowledged uncertainties, as well as a need for DNOs to engage regularly with Ofgem to understand its intended outcome of re-opener processes etc, with little or no real benefit to electricity consumers.

1.1.2. Example: Uncertain costs – pass-through

Ofgem proposes to introduce cost pass-through mechanisms "*for costs incurred by the DNO over which they have limited control*"⁸³. Pass-through items represent costs that are either outside DNOs' control (such as business rates) or that have been subject to separate price control measures (such as Transmission Connection Point Charges and Smart Meter Communication Licensee Costs).

Pound for pound, any difference between forecast costs and costs ultimately incurred has a bigger impact on the difference between Allowed Revenue than other cost areas (because all costs flow directly to in-year revenues).

A best endeavours obligation would oblige DNOs to incur additional costs forecasting these activities, despite these being acknowledged to be outside of DNOs' control or subject to separate regulatory processes.

⁸¹ RIIO-ED2 Draft Determinations, Overview document, paragraph 6.2

⁸² RIIO-ED2 Draft Determinations, Overview document, paragraph 6.5

⁸³ RIIO-ED2 Draft Determinations, Overview document, paragraph 6.4

For example, in the case of forecasting of supplier of last resort payments, the change to a best endeavours basis may well oblige the DNOs to carry out much closer and more frequent monitoring of supplier financial health on an ongoing basis, such as employing special analysts to assess the likelihood of suppliers ceasing to trade and, therefore, incurring the associated additional cost. Customers would not benefit from this incremental cost.

1.1.3. Example: Sales response to external stimulus

In estimating future Recovered Revenue, DNOs have to forecast the amount of electricity that will be used by different customer groups during the relevant Regulatory Year. Historically, the biggest factor affecting customer usage has been the weather (in itself, not a factor that it is easy for DNOs to forecast 15 months ahead). However, increasingly uncertain times mean that there is much greater uncertainty about future electricity usage.

Factors such as changes in customer working practices, responses to wholesale energy prices and government policy changes designed to achieve the UK's transition to Net Zero can all materially change consumption by individual customer groups.

A best endeavours obligation applying to forecasting of Recovered Revenue could suggest an expectation by Ofgem that DNOs invest considerably more effort in detailed forecasting of the macro-economic and political factors that drive this. There is no evidence to suggest that more effort in forecasting these factors, and the cost of doing so, will be in customers' interests.

1.1.4. Example: Setting of network charges for RIIO-ED3

The proposed best endeavours obligation would apply to DNOs when setting network charges for the first years of the RIIO-ED3 period. More than half of the routine annual cycles of setting network charges undertaken in RIIO-ED2 will involve setting network charges for the RIIO-ED3 period. Ofgem has provided no guidance on its expectations here.

It is very unlikely that DNOs would have visibility of sufficient aspects of the future price control to accurately set network charges on that basis 15 months in advance.

1.1.5. Example: Considering whether to seek consent to re-set network charges with less than 15 months' notice

Once network charges have been set, the only recourse DNOs have if it becomes clear that Allowed Revenue and Recovered Revenue are divergent would be to seek Ofgem's consent to re-set network charges at very short notice, in time to affect in-year revenues. The move to best endeavours is likely to result in an additional burden for Ofgem in considering requests as well as more frequent, later, changes to network charges. Such a requirement could be triggered by any factor that affects Allowed Revenue or Recovered Revenue in a Regulatory Year for which network charges have already been set, including a change in forecast inflation or the forecast risk free rate, or any change in legislation that could result in additional expenditure.

Moreover, it is not clear in the current drafting that "*setting Network Charges*" refers to an event that happens only once for each regulatory year. Setting network charges is an activity that DNOs undertake at least once a year (and sometimes more often). The obligation could be read as requiring DNOs to use their best endeavours to lobby Ofgem to waive the 15 months' notice requirement for setting network charges that have already been set every time they go through the process of setting network charges.

2. Ofgem's suggestion that the proposed move to self-publishing the Allowed Revenue justifies the change in obligation misrepresents the extent to which this change will improve DNOs' ability to forecast Allowed Revenue more accurately

Ofgem partially justifies its proposal to move to a best endeavours obligation by reference to its proposal that Licensees will be given more control of the process of setting Allowed Revenue.

This process change does not impart on DNOs any significantly greater ability to forecast Allowed Revenue accurately. While there will be some components of Allowed Revenue that DNOs may have superior forecasts than are available to Ofgem, such as latest expenditure plans for certain activities, it is not the case that DNOs have a universal view of all future expenditure, economic conditions, legislative decisions, etc.

DNOs will still be required to forecast Allowed Revenue based on the algebra specified in the licence. As explained in the examples above and in DNOs' correspondence with Ofgem, a considerable proportion of the elements of

Allowed Revenue are subject to forecasting uncertainty. Increasing the level of obligation will not increase a DNOs' visibility of accurate forecasts without considerable effort being expended.

The move to self-publishing the Allowed Revenue will also not change the considerable challenges associated with forecasting customer consumption.

Ofgem recognises that this new process of self-publishing Allowed Revenue will need to be supported by sufficient guidance⁸⁴. Once such guidance has been developed, it would be far more appropriate to oblige the DNOs to comply with this guidance than to introduce a broader obligation that may result in costs being incurred that are not in customers' interests.

3. The change in standard for DNOs cannot be justified by reference to the standard applied in other sectors

Ofgem partly justifies its approach by reference to a desire for alignment between sectors.

The DD rightly states that there “*should be a reason for inconsistency between sectors*”⁸⁵. The DNOs believe that there are strong reasons to justify a different approach for electricity distribution.

The process for setting network charges for DNOs is quite different to other sectors, such as gas distribution. Ofgem considered these differences in reaching its decision in respect of RIIO-ED1 and concluded that it was appropriate to set the level of obligation at a lower standard for DNOs than for GDNs or TOs.

The arguments for DNOs to have a different approach to other sectors have strengthened during RIIO-ED1, in particular with the introduction of the requirement to give 15 months' notice of changes to network charges and the additional forecasting complexities and difficulties associated with that.

These forecasting difficulties will be compounded by the extra costs that will be incurred due to Ofgem's intended move to a greater proportion of costs being included in in-year revenue calculations. Ofgem's proposal to remove the lag to changes flowing into Allowed Revenue that is applied in RIIO-ED1 to many mechanisms further increases the difficulty associated with forecasting Allowed Revenue, and the costs that would need to be incurred to meet a best endeavours obligation. Where GDNs will set network charges in possession of the majority of the actual economic data, performance and spend data that will flow into the Allowed Revenue calculations, DNOs will set network charges in the absence of that data.

Furthermore, Ofgem proposes to set DNOs the more accurate target of “*equal to*” rather than the target of “*does not exceed*” that is applied to GDNs and TOs⁸⁶. While we agree that this different target more accurately reflects the intent of the price control, it is a different standard to that applied to GD and requires greater accuracy to achieve it. The level of uncertainty in forecasting both Allowed Revenue and Recovered Revenue means that the two ultimately being exactly equal would be a very rare event. After all, a GDN could more easily achieve its obligation by systematically targeting that Recovered Revenues are lower than Allowed Revenue. That option is not available to DNOs.

In reality, the complexities and difficulties involved in setting network charges will increase from RIIO-ED1 to RIIO-ED2, even without any change to the level of obligation applied. This will cause DNOs to incur additional costs. These costs will ultimately be borne by customers.

This increases the difference between ED and GD and justifies continuation of a difference performance standard. Alignment between sectors simply cannot be used to justify this change.

⁸⁴ RIIO-ED2 Draft Determinations, Finance Annex paragraph 10.123

⁸⁵ RIIO-ED2 Draft Determinations, Finance Annex paragraph 10.129

⁸⁶ ED SpC 2.1 paragraph 2.1.3, GD SpC 2.1 paragraph 2.1.3, TO SpC 2.1 paragraph 2.13

4. Ofgem's proposed change to the level of obligation is internally inconsistent with its proposal to remove the current lag on many aspects of economic condition or performance flowing through to Allowed Revenue

Ofgem proposes to remove the lag that currently applies to many aspects of the price control. Ofgem acknowledges that the current lag in performance flowing through the revenues was introduced to improve predictability of charging⁸⁷.

While the text of the Draft Determinations focusses on incentive revenues, we understand that Ofgem's proposal is much wider and that it proposes changes to the timing of many components of the Allowed Revenue so that adjustments to Allowed Revenue are applied in the year of performance. We understand that changes are proposed to the timing of revenues for aspects such as incentives, pass-through costs, uncertainty mechanisms and price control close-out mechanisms.

At present, DNOs have access to approximately three quarters of the performance data for aspects of the price control that are lagged by two years at the time of setting network charges (15 months prior to the relevant Regulatory Year commencing). The fact that DNOs did not have access to all of the performance data when setting network charges for RIIO-ED1 was part of Ofgem's rationale for applying a lower standard to DNOs than GDNs.

For RIIO-ED2, DNOs will not have access to any of that data. They will have to rely on forecasts. Costs will be incurred in determining those forecasts. For aspects of the price control such as pass-through components, the costs of developing those forecasts to a best endeavours standard could be considerable.

We understand that the change will also extend to removal of the current "MOD_t" term⁸⁸ with all changes to totex allowances arising from the considerable number of uncertainty mechanisms being reflected in retrospective changes to Allowed Revenue for the relevant Regulatory Year.

The removal of the MOD_t term means that DNOs face the potential for the level of Allowed Revenue for any one given Regulatory Year to be recalculated multiple times after the relevant Regulatory Year has ended. Indeed, it is expected that changes to RIIO-ED2 Allowed Revenues will continue well into RIIO-ED3 due to aspects of RIIO-ED2 close out.

Ofgem also plans to change the approach to forecasting of inflation with the removal of the current approach of forecasting inflation using a standard forecast (RPIF) and truing up to actual inflation (RPIA) on a lagged basis once actual data is available⁸⁹. Inflation shocks are very difficult to forecast and can drive very significant differences between forecast and actual Allowed Revenue calculations. This change will further increase the difficulty of providing accurate forecasts of Allowed Revenue.

Ofgem has recognised the difficulties associated with forecasting several material aspects of Allowed Revenue in its proposal that inflation and incentives should not be subject to penalty interest⁹⁰. It is illogical for Ofgem to insist that DNOs should incur the costs associated with meeting a best endeavours standard for forecasting such aspects of Allowed Revenue when elsewhere in the price control package it recognises the difficulty of achieving accuracy.

Furthermore, if DNOs obtain updated evidence that shows that material changes to Allowed Revenue should be made relative to those assumptions used in setting network charges the only recourse DNOs have would be to seek Ofgem's consent to re-set network charges at very short notice, in time to affect in-year revenues. The move to best endeavours is likely to result in an additional burden for Ofgem in considering requests as well as more frequent, later, changes to network charges.

⁸⁷ RIIO-ED2 Draft Determinations, Finance Annex paragraph 10.163

⁸⁸ See draft SpC 2.1 paragraph 2.17

⁸⁹ See draft SpC 2.1 paragraph 2.1.9

⁹⁰ RIIO-ED2 Draft Determinations, Finance Annex, paragraph 10.160

5. If Ofgem has views as to specific actions that DNOs should undertake, it should make those requirements clear on face of the licence rather than imposing a generic obligation

Ofgem suggests that DNOs' interpretation of the expectations of a best endeavours obligation may be more onerous than its own expectations of the actions required to achieve the obligation⁹¹.

Ofgem's articulation in the Draft Determinations of its expectations on DNOs is not fully consistent with our understanding of case precedent-related to the requirements under a best endeavours obligation. Best endeavours is clearly a legal test and we would expect that, unless further qualified by the licence, it would be this legal test that would be considered during any enforcement action. In the absence of specific Ofgem guidance setting out the expectations under the proposed obligation, DNOs either face (a) a considerable, unfunded obligation that creates no benefit for customers or (b) an unacceptable compliance risk if they assume that Ofgem actually requires a somewhat lower level of activity than it has imposed as an obligation and will assess any alleged compliance breach against this lower standard.

Without prejudice to our position that the obligation should continue to be based on reasonable endeavours, if Ofgem ultimately disagrees with the DNOs and opts to introduce a best endeavours obligation, it must include a set of exhaustive guidance specifying the actions that DNOs should undertake to meet the standard. This guidance should either be set in the licence itself, or in guidance that has the appropriate power to qualify the obligation in the licence.

If Ofgem intends that a DNO that complies with the associated PCFH guidance will be deemed to have complied with the over-arching obligation this should be made clear on the face of the licence⁹². We note that the proposed PCFH guidance on forecasting Variable Values referred to by Ofgem is not yet available. It is essential that well-developed drafts of these obligations should be made available to DNOs as soon as possible so that they can consider how any new requirements will be implemented.

It is essential that Ofgem provides guidance on how attempts to improve the accuracy of revenue forecasts should be valued so that DNOs can make decisions regarding whether an action is or is not required in order to comply with the proposed obligation.

6. Ofgem's proposal is also inconsistent with its assumptions in other aspects of price control package.

Ofgem acknowledges that its proposed new obligation is more stringent than the current obligation⁹³. A more stringent obligation will require additional effort by DNOs. The costs associated with these extra activities are not included in current cost base that Ofgem proposes to use to set totex allowances. As such, Ofgem is currently proposing to impose a new, unfunded obligation on DNOs.

Notwithstanding our view that the proposed change to the level of obligation should not be implemented, if Ofgem persists with this change, cost allowances must be increased to cover the costs of this additional obligation.

⁹¹ RIIO-ED2 Draft Determinations, Finance Annex, paragraph 10.127

⁹² RIIO-ED2 Draft Determinations, Finance Annex. paragraph 10.131

⁹³ RIIO-ED2 Draft Determinations, Finance Annex. paragraph 10.127