RIIO-ED2 Draft Determinations Core Methodology Document Consultation response

Annex 2: Core Methodology Response

August 2022

Contents

Introduction

In this annex we set out our response to the questions set out in the Core annex of the Draft Determinations (DD).

In considering the questions raised by Ofgem, and our response to these, we have engaged with our CEG as well as wider stakeholders to understand their views on the DD and the positions set out by Ofgem. We have done this throughout the ED2 preparation process and consider that the views of our customers, stakeholders and CEG remain as important as ever. It remains critical that the settlement which is finalised for ED2 enables ENWL to deliver for the communities we serve. From our stakeholder engagement over the summer we understand that our stakeholders will respond independently setting out their views. It is vital that Ofgem act on these in the development of Final Determinations (FD) reflecting regional stakeholders needs.

We continue to welcome the ongoing engagement with Ofgem, both through bilaterals and working groups and view this as vital as we work through the changes required between DDs and FDs to ensure a workable and acceptable framework/ determination. We would note that the time remaining is short and there are significant amounts of detail still needing to be developed. This can be achieved but requires both DNOs and Ofgem to constructively work together in a solution orientated way. We are fully committed to playing our part in this regard. We also suggest given the time available and volume of work need that Ofgem consider its short-term resourcing requirements and scale as appropriate.

The responses contained in this and the other documents should be considered alongside the detailed comments we have made within licence drafting working group (LDWG) and its associated issues logs. We recognise that the licence for ED2 is not a formal part of this DD consultation stage and a separate process will be run to consult on the licence to be put into place, therefore we have not sought to include views on the licence at this stage in our response. An effective Ofgem led informal and formal licence consultation process is critical including the timely provision of updated issues logs showing how Ofgem has considered and actioned DNOs feedback contained within.

Further, whilst we note the DDs are a consultation with the opportunity to provide our views and evidence on the proposals contained within, we remain seriously concerned that the process and timing is not optimal and risks this important part of the ED2 process being rushed, especially considering the range and complexity of changes from RIIO-ED1. We remain of the view that an eight-week consultation period, especially given the timing over the summer, is not sufficient for such an important part of the process and urge Ofgem consider this in future stages and price review processes. This issue of process and the time available to fully understand the DDs and develop a fully informed and thought out response has further been exacerbated by additional and short order data requests from Ofgem with response dates overlapping, ultimately diverting resources away from our core response at times.

On next stages and steps in the process we remain open to working constructively with Ofgem and others to develop workable solutions for ED2. We urge that Ofgem are open and transparent and encourage that this occurs on an ongoing basis and ahead of FDs, including the expediting and sharing of decisions where possible. It is important that FDs contain no surprises to DNOs and we are of the view that if there are, this is unhelpful to all parties and a failure of process. This is of increased importance when considering the area and outcomes from Ofgem's cost assessment process.

To that end, we will continue to feed in evidence and information for the consideration of Ofgem over the coming weeks and months. We expect that Ofgem will consider this information on the same basis as it will the information contained in this document and included in our wider DD response.

1 Embedding the consumer voice in RIIO-ED2

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

We welcome the lack of a prescriptive approach towards CEGs, but we are concerned that whilst Ofgem accepts the proposals for CEGs 'or similar panels' in ED2, the language in the detail is very focused on CEGs specifically. Language that better reflects general 'independent scrutiny' would be more appropriate so as not to be unintentionally prescriptive as to any specific format.

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?

We suggest the relevance of this as well as the value cross-CEG reporting will bring is low due to the regionally-driven outputs and the differences between DNO plans. Our view is that there is a substantial risk that significant work may be expended by CEGs only to conclude that the common and co-ordinated reporting will in fact come from annual performance reporting[1] undertaken and published by Ofgem.

We are further concerned by the use of the phrase "*CEGs working together*" which assumes DNOs will all retain the same structure and form without consideration that this isn't required to be the form in ED2. Our proposed panel structure will enable in-depth and specialised expert scrutiny, split between topic-specific expert panels, rather than continuing with a single CEG format.

2 Networks for Net Zero

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

Whilst we recognise there is a need to assess DNOs LRE, we disagree with how this has been done by Ofgem for Draft Determinations (DD) and are keen to work collaboratively with Ofgem to seek a better and more transparent approach ahead of Final Determinations (FD).

Ofgem has consciously enabled, in its FBP guidance, a bottom-up regional approach to this vital policy area, which we think is the right approach. It is important that this work, and the regionally reflected outcomes are considered and used as an input to calibrate the allowances within the full Load Related area. For example, we suggest that ENWL System Transformation outcomes should be used with LRE to distribute/calibrate the allowances between primary, secondary and other allowance pots.

We share our views on each aspect of the adjustment in the following sections.

Overview of Scenarios

We are surprised that Ofgem has chosen at this late stage to apply a common scenario of ESO FES System Transformation (ST). The method of adjusting our Central Outlook scenario to arrive at ST volumes is, in our view, without consideration of the impact and the outcome of adjustment delivers an incorrect treatment of costs pushing all these to uncertainty impacting upon future customers. This issue is discussed further in our response to the capitalisation rates proposed for variant allowances in question 30 and 31 under the finance section.

[1] Recent example RIIO-1 Electricity Distribution Annual Report 2020-21 | Ofgem

The use of the ST scenario risks not allowing networks to adequately support the transition to Net Zero. We are also concerned that the sole use of this national scenario to determine allowances fails to take appropriate account of the differing levels of regional and sub regional ambition demonstrated by stakeholders.

In our preparations for the ED2 FBP submission we modelled all four scenarios of the common FES/DFES scenario framework as reflected in our area. These modelled scenarios detail the expected costs for the ST scenario in our region. These are detailed in Annex 3a of our final business plan and shown in the diagram and table below (fault level and connections funded reinforcement included in EHV and HV/LV figures).

Given that the ENWL ST 2020 scenario (based on the 2020 FES ST scenario) does not consider a 2030 ban on sales for purely internal combustion engine (ICE) vehicles and a 2035 ban on plug-in hybrids, we therefore treated this scenario as non-compliant with Ofgem's RIIO-ED2 business plan guidance.

[redacted]

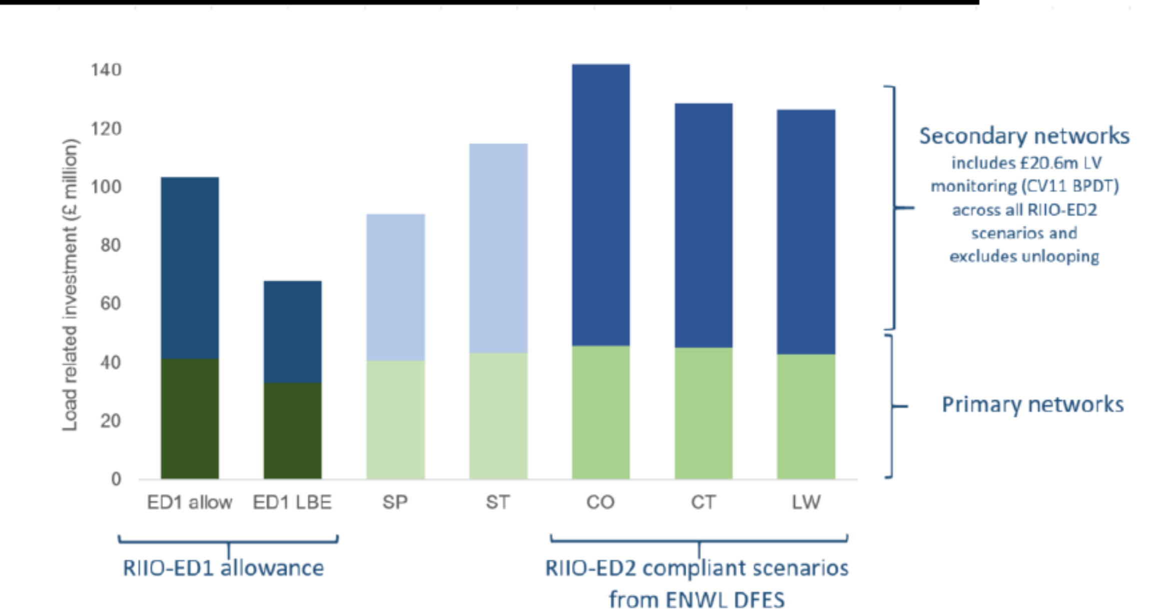


Table 1: Impact of required investment by voltage, and by scenario

Load Related Investment	**Central Outlook** (informs baseline allowance), £M	**System Transformation,** £M	**Leading the Way** (lowest LRE compliant scenario), £M	**Accelerated Decarbonisation CO** (meeting local stakeholder ambitions), £M
EHV	46	45	43	102
HV and LV	96	72	84	196
Total:	**£142**	**£117**	**£127**	**£298**

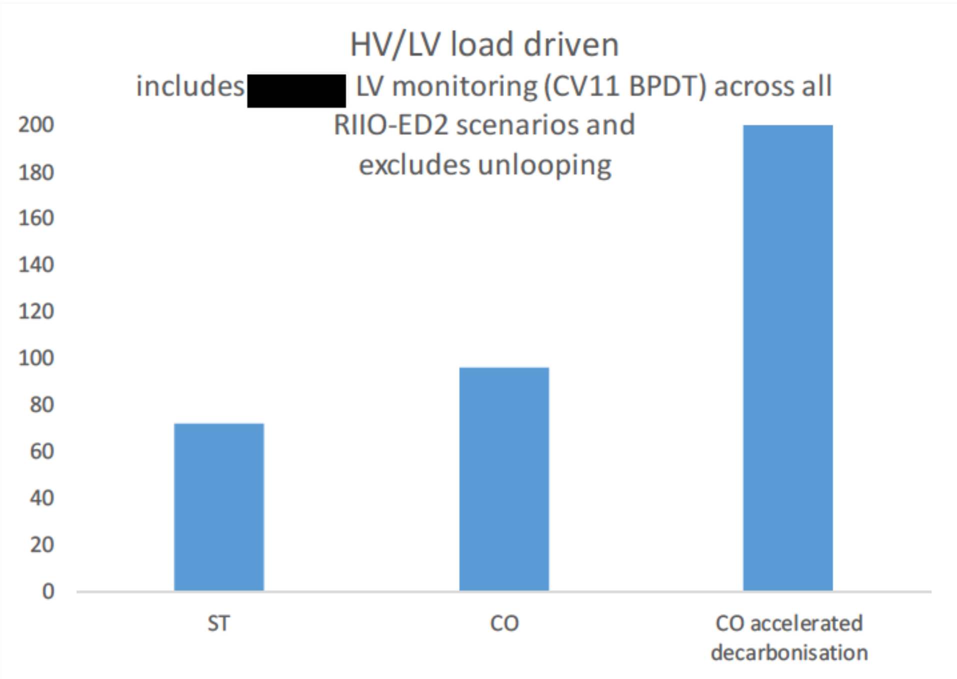
The inclusion of stakeholder views and regional factors is, in our view, a critical component of determining adequate allowances. In order to avoid an arbitrary approach, we propose that Ofgem use either:

- our Central Outlook scenario LRE that captures the highest certainty view for our region and is compliant with Ofgem guidance, this is our recommended approach; or

- allocate the LRE that Ofgem has proposed based on the disaggregation model using the split between EHV and HV/LV LRE from our System Transformation scenario LRE, which whilst not compliant with Ofgem's original guidance is based on our robust ATLAS bottom up forecasts and captures through detailed network impact analysis, a sensible split between primary and secondary LRE for our area.

Given that our EHV schemes for RIIO-ED2 are driven by well justified planned developments rather than volumes of LCT uptakes (see next subsection on "EHV schemes"), this means that the ST scenario has a very low LRE associated with secondary network interventions. As shown in figure 2 below, the ST is 25 percent lower than our "best view" Central Outlook (CO) and nearly a third of our accelerated decarbonisation CO scenario that corresponds to the expected volumes of LCTs that our local stakeholder ambitions expect. For example, regional ambition in Greater Manchester aims to meet Net Zero before 2040 (as demonstrated by the accelerated decarbonisation scenario shown in Table 1 above).

[redacted]



<u>EHV Schemes</u>

Our EHV load related investment programme is based on strong developer and planning evidence containing only those planned developments with a high certainty of building. These are detailed in section 4.3 "*stakeholder engagement*" of our LRE Annex 3a on methodology. This explains the small differences between the EHV load related investment programme across the different scenarios modelled, given that this is a) less driven by volumes of domestic EVs and heat pumps and b) mainly driven by economic developments identified as high certainty projects.

Table 2 below shows all EHV schemes that have been identified between Central Outlook, which informed our ex-ante LRE, and System Transformation scenarios from the ENWL DFES.

Table 2: Varying EHV schemes by scenario

Load Related Investment (location or site-specific ID)	**EJP Ref**	**Central Outlook** (informs baseline allowance)	**System Transformation**
Eastlands		Yes	Yes
Queens Park		Yes	Yes
Baguley		Yes	Yes
Blackfriars		Yes	Yes
Chorley South		Yes	Yes
Hattersley		Yes	Yes
Little Hulton	LRE-EJP1	Yes	Yes
Frederick Rd BSP	LRE-EJP2	Yes	Yes
Wigan BSP		Yes	Yes
Bow Lane - Whittle Le Woods Group		Yes	**No**
Southern Gateway	LRE-EJP3	Yes	Yes
Northern Gateway / South Heywood	LRE-EJP4	Yes	Yes
Mayfield Re-gen	LRE-EJP5	Yes	Yes
Moss Nook		Yes	Yes
Ambleside Windermere Group		Yes	Yes
Pirelli Capontree Westlinton Group		Yes	Yes
Lower Darwen	LRE-EJP13	Yes	Yes
Nelson		Yes	Yes
Bredbury Harmonics	LRE-EJP14	Yes	Yes
Total number of projects:		**19**	**18**

Credibility of ENWL approach

We welcome the use of the high-level load related investment methodology framework as proposed by ourselves and shown in Figure 4 of Ofgem's RIIO-ED2 DD Core Methodology document.

Following our proposed framework, we have:

- applied our credible ATLAS methodology to produce all forecasting outputs for the scenarios modelled. ATLAS is a transparent and published methodology and to improve transparency we have presented in our LRE Annex 3b detailed insights and values/graphs on various forecasting components
- identified through impact analysis EHV schemes that in line with ATLAS methodology are driven from evidence based planned developments i.e. considering connections activity using confidence factors based on historical performance and stakeholder engagement inputs only for projects with high certainty in terms of demonstrating secure funding, strong backing from local/central government, planning consent and ongoing development work
- used a credible approach to inform secondary network reinforcement using our Future Capacity Headroom (FCH), which as shown in LRE Annex 3b on methodology (section 5.3) can better represent local impacts and reflect local forecasts compared to other alternative modelling approaches, and
- considered a "*flex first*" approach in optioneering to estimate the savings from flexibility services as described in LRE Annex 3b on methodology (section 6.2).

We feel the need to highlight the credibility of our approach, as opposed to the modelling approach in the Ofgem disaggregation model used for the DD in LRE. The use of a bottom-up System Transformation scenario for our region using the credible modelling approaches listed above results in a 5 percent reduction in EHV reinforcement allowance compared to our FBP proposal that was based on the Central Outlook scenario. This is a much lower reduction than the 22 percent reduction resulting from Ofgem's high level approach to align with a System Transformation scenario.

This is why as we recommend above, if Ofgem does not want to proceed with our recommended Central Outlook approach, a sensible approach would be to allocate the LRE that Ofgem has assessed using the disaggregation model taking into account the split between EHV and HV/LV LRE from our System Transformation scenario LRE.

Again, it should be noted that even though this scenario is not the highest certainty view for the future of our region, it is based on our robust ATLAS bottom up forecasts and captures through detailed network impact analysis, a sensible split between primary and secondary LRE for our area.

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

We agree with the introduction of an LV services volume driver to deal with the uncertainty of the work required at the service point position, and this aligns with our proposal in this area within our FBP. We do have some comments as regards the parameters proposed for this volume driver, and our comments should be read in conjunction with the comments on the Secondary Network Volume Driver as the issues and challenges are similar.

We also agree with the principle of a mechanistic volume driver for secondary network reinforcement, indeed we originally proposed this concept to Ofgem back in 2018 and have worked with Ofgem and other DNOs to develop the concept, with options, into potentially workable solutions. There have been a number of challenges in getting to this point and indeed we considered at the time of submitting our FBP that the challenges in some areas meant that a mechanistic volume driver in this area could be a price control too soon. We suggested it would be better worked on in ED2 for implementation in ED3, given the vital importance of having a robust and workable LRE mechanism for ED2.

We do welcome the ambition of Ofgem to try to put this in place for ED2 and maintain our support for the concept of a fully mechanistic volume driver for secondary network reinforcement.

It is critical that such a mechanism is carefully designed and implemented given the importance of LRE in this period and in the context of the current point in time on the transition to Net Zero and DNOs.

The UM design for both volume drivers should ensure the mechanism is fast acting, agile and does not have unintended consequences nor acts as a blocker to Net Zero developments. These fast acting and agile characteristics must extend to all aspects of the DNO framework including:

- simple and transparent mechanistic reporting,
- fast acting cashflows through revenue adjustments,
- financial parameters that do not have unintended consequences, and
- do not result in unduly favouring one solution over another.

Importantly, the Access SCR is another major Ofgem-driven change that needs to be facilitated by ensuring LRE mechanisms for ED2 work effectively.

We remain of the view that there are still issues of important detail that need to be solved by FD, particularly around the subject of volume driver controls, clawback and ensuring indirect costs are adequately catered for.

Whilst safeguards are important, there is a significant risk that implementation by Ofgem of too many controls and measures could result in the mechanism becoming unwieldy and outweigh the benefits that an automatic mechanism brings. Overall, the secondary network volume driver could result in a large amount of complexity, lack of transparency for stakeholders and does not at present seem to promote the use of flexibility.

If these issues can't be adequately resolved, having a more traditional re-opener in the space of secondary networks should still be considered because, when combined with the Totex Incentive Mechanism (TIM) this arrangement would naturally favour and incentivise DNO's to utilise flexibility solutions where these are economically efficient.

Our view is the ED1 process for flexibility drives the right behaviour, we provide further detail below as to how the framework can be adjusted to ensure flexibility is adequately catered within the mechanisms.

We consider there are four key points to raise on the DD proposals which we provide in further detail below:

1. Unit rates,
2. Volume driver controls,
3. Flexibility procurement, and
4. Financial parameters.

We take each of these in turn below:

1. Unit Rates

Unit rates – feeders

We would like to bring to Ofgem's attention that in our FBP we have populated the CV2 table cells AU181 and AU183 with gross lengths of HV and LV feeder km, i.e. with feeder length corresponding not only to capacity constraint at feeders but also inclusive of feeder km to be installed from distribution substation reinforcement. Table 3 shows the net volumes, i.e. purely capacity constraint feeder length, that should have been reported in CV2. It also presents the gross volumes presented and the corresponding cost of our BP proposal.

Our analysis on HV and LV feeders reveals that ENWL unit rates are [redacted] in £/km compared to the proposed values in Ofgem's DD. We understand that this difference is due to the mix of overhead lines and underground cables in our network. The cost differential between OHL and U/G cables will be familiar to Ofgem and must be taken account of in coming to an accurate composite unit rate for circuits. Consideration should be given to having separate unit rates for OHL and U/G cables.

Table 3: Gross and net feeder lengths

Circuit voltage	Gross volume (km) (total length across all types of reinforcement)	Net volume (km) (only for feeder capacity constraints)	Cost (£m) (based on net volumes)
LV	235	191	[redacted]
HV	282	271	[redacted]

<u>Unit rates – unlooping</u>

We understand that Ofgem's proposed cost in the DD for a single full unlooping intervention corresponds to the cost of one service unit and two cut outs, i.e. 1 x £1.4k + 2 x £0.25k = £1.9k. This cost estimate is unrealistic given that the unlooping activity covers a broad range of legacy installations and often requires additional work such as reconfiguration or re-routing of existing service cables, installation of sub-main extensions etc. As such, use of in-situ like-for-like asset replacement costs does not reflect the complexity of the work often required.

Our experience based on increase in this activity in the latter part of ED1 shows that the indirect costs are significant in this area, as the unlooping activity is significantly different to a like-for-like asset replacement. The indirect cost element for this activity should not be under-estimated and should be included in the unit cost for this activity. Our FBP showed a breakdown of the costs for each aspect of unlooping, with a full cost of [redacted] per intervention. It should be noted that an intervention covers the full solution of unlooping, whereas Ofgem in the DD has disaggregated each component down to an individual asset by asset basis, not taking into account other associated costs to the direct work carried out.

We consider that further work is required via working groups to establish an efficient unit cost schedule for this activity which reflects the nature of this work. The impact of indirect costs in this area should also not be under-estimated and should be appropriately catered for when setting the mechanism design and parameters.

We understand that Ofgem has assessed the unit rates presented in the DD based on information and data provided across all DNOs in their FBPs. We also suggest that further work is undertaken before the FD to ensure absolute clarity of unit reporting in terms of properties, services and equipment counts (cut-outs etc,) to ensure consistency across DNOs.

<u>Unit rates – cut out replacement</u>

Similarly to the unlooping programme, the reduced unit rates proposed in Ofgem's DD (i.e. £250 per unit compared to [redacted] proposed in our ED2 plan) suggests that Ofgem has not taken a full view of the activity required here, with a key component being how the cut-out can be changed, and whether this can be done live, without any associated civil works, or if it is required to be performed dead for safety reasons. Changing a cut-out dead incurs excavation, backfill and reinstatement costs. Our experience tells us that a significant percentage of cut-out changes need to be performed dead, with the associated costs that these bring. This therefore brings the unit rate substantially higher than that currently derived by Ofgem.

Ofgem is therefore proposing to set unit rates based on incomplete information without full consideration or understanding of the activity and its requirements. In turn this will result in the underfunding of key activities which our customers will need. The rate needs to be set at an efficient level, not unrealistically low and further work is needed by Ofgem to understand the activity and develop the associated unit rates.

Ofgem has separately asked for additional information to inform the setting of unit rates for fuse upgrades as part of the LV Services Volume Driver which we will be providing within similar timescales to this response. As described in our FBP and associated EJPs in many cases (though not all), the upgrading of a customer fuse to facilitate an LCT also requires the changing of a cut-out. This interaction should be considered when setting the unit rates for other LV services activity.

Finally, as this is customer driven work, needing to be scheduled with customers, the associated indirect cost needs to be considered when setting unit rates. As with unlooping unit costs, further work is required between now and FD to fully inform this aspect of the volume driver.

2. Volume Driver controls and framework

We recognise that all novel mechanisms, particularly newly introduced proposals may require some “checks and balances” to satisfy Ofgem that they are sufficiently robust. However, there is a point where the “checks and balances” become so significant that a rethink might be required to more fundamentally address any risks and issues for customers, Ofgem and companies.

Volume Driver Cap

A cap should not be set in the first place as it places a stop on our ability to meet consumers’ needs. How critical or not any cap is, is dependent upon the final design of the mechanisms, the level of baseline allowances and outturn of consumers’ actual needs.

We see that there is an inconsistency using an ESO FES scenario to define baseline allowance and a CCC scenario to quantify the cap of the funding under uncertainty using volume drivers. We are concerned about the proposed calculation of the cap for volume drivers (in £) compared with the volumes of LCTs associated with a) the ESO FES ST scenario that defines baseline allowance; and, b) the CCC Balanced Pathway scenario that defines the cap. Our understanding is that there is a significant difference in LCT volumes between these two scenarios. More specifically, using the LCT volumes shown in Ofgem’s ED2 BP guidance the CCC BP scenario considers over 3.5 times more LCTs from ESO FES ST by 2030 (methodology explained in our LRE Annex 3a on methodology).

In the Ofgem ED2 BP guidance there is information around energy and LCT volumes for 2030 between the ESO FES and CCC scenarios. Even though we can allocate top down from FES ST and CCC BP scenarios the LCT volumes to our area, not all LRE items are driven by energy and LCT uptakes. Importantly, the HV and LV reinforcement is driven not solely by demand or LCT uptake, but by generation. There are also concerns over the limitations to correlate the LCT volumes with requirements for interventions to tackle such items as harmonic distortion issues.

We believe that a sensible scenario to define the cap for volume drivers should consider the early Net Zero targets announced by Local Authorities in our region. In our proposed LRE under uncertainty we included the investment associated with accelerated decarbonisation of our region, where a large part of our licence area meets Net Zero before 2040 based on stated ambition. Should Ofgem not allow the use of regional ambition in determining the cap value, then this risks systematically frustrating Net Zero in our region.

We agree with the proposed review of the cap on volume drivers by mid-RIIO-ED2 as we would need to facilitate potential accelerated decarbonisation trends that align with the early Net Zero targets announced by Local Authorities in our licence area. This approach allows both Ofgem and ourselves to demonstrate that funding is sufficient to meet regional political and stakeholder ambitions for Net Zero whilst protecting customers against potentially inefficiently timed expenditure.

Use of indicators

The proposed automated volume driver will use four indicators to support the needs case for the volumes of work undertaken. These metrics are:

i. transformer utilisation.
ii. circuit utilisation proxy.
iii. LCT growth.
iv. Broad measure of load growth – using annual load growth from representative sample of installed LV monitors.

Since the publication of DDs, we now understand that a fifth measure is to be added to this set of indicators.

Initially we were concerned about the lack of detail in how these indicators will work in conjunction with the automated volume drivers. But the information shared by Ofgem in the recent working group meetings and the discussion around that detail means that we are also concerned by the burdensome complexity of the five indicators and the suggestion that the reporting of some indicators will need to be independently audited.

It is right that DNOs should publish a set of indicators that Ofgem and stakeholders can use as a check against expenditure for the volume drivers. But simplicity is the key and we believe that Ofgem has chosen the right areas of utilisation, LCT growth and load growth, and would urge Ofgem to look at simplifying the requirements and triggers for further investigation. We note that the current DAG arrangements provide the necessary confirmation that the data has been appropriately gathered, manipulated and published.

These proposed controls need significant work over the autumn to allow DNOs and stakeholders to better understand how these controls will interact with the volume driver by FD. It is unclear how Ofgem will use the trend of the five indicators and use the spot values.

We remain concerned that there is no clarity on how associated assessment processes and any subsequent clawback mechanism will work in relation to the controls, this poses a significant risk to DNOs who will make decisions on the best information available at the time. The use of any of these controls must not result in a hindsight review and clawback. A vital principle must be that decisions made at the time they were made were not manifestly wrong based on the information at the time. Should a mechanism be put in place it must be fully defined sufficiently clearly at FD stage and included in our Licence.

3. Flexibility Procurement

We operate a Flexibility First approach, before investing in providing capacity via more traditional network solutions. We are still uncertain as to how the procurement of Flexibility Services fits into the LRE UM toolkit that Ofgem proposes. The DD does not clearly lay out Ofgem’s vision in this area, and this is one of the key challenges a volume driver poses.

This is surprising given many stakeholders view of the potential role of Flexibility Services, including Government and Ofgem itself having worked on the smart systems and flexibility plan. It looks a major gap at DD.

We consider that setting a unit rate within the volume driver comes with risks of distorting the market and feel that changes to flexibility allowances is better dealt with via the Load Related re-opener. We cover this more in our response to question 5 below.

4. Financial Parameters

As we touch on in our response to question 3 of this document, Ofgem's proposals on capitalisation rate for volume drivers and re-openers results in an asymmetrical treatment of costs, pushing all uncertain costs onto future customers. We provide further information on this in our response to question 30 and 31 of the Finance annex, however it is important that this is not considered as solely a finance issue, rather it has a significant operational impact and is fundamental to the delivery of the policy on LRE and enabling Net Zero.

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

We agree in principle with the proposal for a LRE re-opener, indeed we proposed a re-opener for all aspects of load in our FBP and welcome Ofgem's acceptance that this is the best way of managing the uncertainty for some categories of LRE spend.

We do, however have some concerns and proposals for revision in three key areas:

Timing

We are concerned as to whether the re-opener as proposed is sufficiently agile to allow investment with confidence due to the timing and materiality thresholds. More specifically, there is only one proposed re-opener window that can be triggered by the DNOs; it opens in mid ED2 and yet we face two significant uncertainties in the price control period. Firstly, the behavioural change due to Access SCR changes, which arguably brings the case for a window earlier in the period to allow for such impacts to be acted upon quickly. Secondly, we now face a real risk of an economic recession in the early part of the price control. This means that a potential economy bounce-back from mid-ED2 onwards combined with the large materiality threshold (currently stated by Ofgem at 1 percent) can result in a real risk of not having any allowance available for necessary flexibility procurement or reinforcement work.

In either case the current design of the re-opener will, in our view, act as a blocker to the Net Zero transition for our region.

We agree with the proposal to put the re-opener outside of the common parameters with a window in April 2025 as this ties in well with other key publications and planning cycles. However, given the scenarios outlined above, we also consider that there should be the opportunity for other windows triggered by DNOs, both earlier, to allow for the impact of Access SCR, and later, to consider impacts of further uncertainties including a potential economic "bounce-back" or other drivers not predicted at this time.

We therefore propose that there is a window in April 2024, a second in April 2025 and a final one in April 2026.

Scope

We have been calling within working groups for Ofgem to confirm which areas of LRE will fall under this re-opener. The consultation position shared at DD is that the re-opener would apply to all other LRE activities which fall outside of the scope of the Secondary Network Volume Driver and LV Services Volume Driver. Whilst this appears clear, there are nuances, for example if it includes NTCC. There is ambiguity in the DD as to the treatment of NTCC and it would be helpful for Ofgem to expand on this definition to list the items that they intend to be covered and state these explicitly within the FD.

We have also proposed that the costs incurred for LV network monitoring fall within the scope of this re-opener. From subsequent discussions with Ofgem via a working group in August we understand that LV monitoring is expected to be within scope of the Digitalisation re-opener. We agree with Ofgem that LV monitoring could be in the Digitalisation re-opener and would welcome that clarity to be laid out in FD.

Finally, as described in our answer to question 4 of this document, it needs to be clear how the treatment of costs relating to flexibility procurement interacts with the LRE mechanisms, and whether all flexibility procurement, regardless of which voltage level, falls under the scope of the load related re-opener. We have inputted solutions to ongoing working groups on this aspect, as well as other LRE regulatory mechanism topics.

Financial Parameters

As touched on in our response to question 3, Ofgem’s proposals on capitalisation rate for volume drivers and re-openers results in an incorrect treatment of costs, raising intergenerational fairness issues, pushing almost all uncertain costs onto future customers. Additionally, the specific capitalisation rate for uncertainty mechanism and re-opener costs does not reflect the actual costs of delivering for customers as indirect and closely associated indirect costs will also need to be incurred so allowances for these indirect and closely associated indirect costs also need to be increased as volumes increase. We provide further detail in our response to questions 30 and 31 in our Finance annex, however it is important that this is not considered as solely a finance issue and full consideration is given to the operational and distributional impact of such a proposal.

We agree with a common materiality applying to this re-opener, however highlight our response to question 6 in the overview document as to our views on what the appropriate rate of the common materiality threshold is that should be applied. For the avoidance of doubt, we consider a common materiality threshold for ED should be no more than 0.5 percent and that this should apply to the load related re-opener.

Should Ofgem continue with the intent to include costs of flexibility procurement within the load related re-opener, then the materiality threshold should be re-considered to ensure that materiality does not present a barrier or disincentive to perform these activities. We propose that in the specific case where flexibility procurement costs exceed the allowances set, then in the context of the load re-opener, Ofgem should either:

a) Set the material threshold for flexibility procurement costs to zero, or
b) Keep the threshold at the proposed common parameter of 0.5 percent and use the costs of the counterfactual (i.e. traditional asset-based solution) rather than the flexibility cost for calculation against the threshold.

We consider that these actions would go some way towards mitigating the risk that the LRE toolkit of uncertainty mechanisms as currently set out in the DD does not currently support flexibility market development.

We note that Ofgem intends to provide guidance on the expectations of an appropriate justification for a re-opener application. It is critical that any guidance which DNOs are obliged to comply with in RIIO-ED2 is available for DNOs to view well ahead of FDs and that this guidance is not developed by

Ofgem in isolation. This should be able to be viewed in line with, and alongside, any drafting of associated licence conditions.

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

We have significant concerns with the Net Zero re-opener as proposed in DDs, but we do support its inclusion within the framework. Our concerns relate to the scope, the triggering party and materiality threshold. We set out our concerns, proposal and reason/justification for each item in turn below:

- **Scope**: Ofgem seem to have narrowed the scope of the Net Zero re-opener from the SSMD, which in itself isn't a concern, however, as we have shared via working groups, we consider that Ofgem has applied the scope of the Net Zero re-opener identical to that which is in place for GD2/T2 without taking into consideration the sector specific differences and differences in the regulatory framework for ED2. The DD proposes that the scope is for "*Changes in national or local Government policy, new obligations arising from the agreement of a Local Area Energy Plan, the change in the pace or nature of the uptake of low carbon technologies, as well as technological or market developments to be reflected in company allowances."* This may be an appropriate scope for GD2/T2, however for some of the items that are proposed to fall within scope, there are already uncertainty mechanisms which deal with these circumstances. For example, changes arising from Local Area Energy Plans, or change in pace or nature of LCTs are very likely to flow through the load related expenditure uncertainty mechanisms rather than the Net Zero re-opener. We consider therefore that the scope should be reviewed in light of the other uncertainty mechanisms that fall within the ED2 framework.

  Further, we note the type of changes Ofgem consider[2] under this re-opener would be (amongst others) *"adjustments to existing output targets or the introduction of new output arrangements through a PCD".* Through licence drafting that has been shared so far, this has been converted to a default position in the licence that all changes would have an associated PCD. We do not consider that this default position is logical as it cannot be known whether changes would be appropriate for a PCD and we will continue to share this position via the Ofgem Licence Drafting Working Group that this should be an option available, rather than a default position embedded within the licence.

  It should also be noted that Ofgem in its DD has removed our proposed UIOLI funding for LAEP activities which was to be included in our NZARD UIOLI proposal in our FBP. We set out our response to the removal of UIOLI in response to question 6 of our ENWL annex.

- **Triggering authority:** We disagree that this should be authority only triggered. It is more than likely that DNOs will have greater insight and foresight than Ofgem into events which will require the application of Net Zero re-opener as defined in the scope.

  During early ED2 policy discussions, Ofgem indicated that this re-opener would be for major change, material items and be driven in part by the advice and guidance from the Net Zero Advisory Group (NZAG). The link to NZAG and indication of this intent, seems to have been lost in the drafting. We do not understand why this would be an authority-only trigger and would call for Ofgem to explain the reason for this and add in windows for DNOs to trigger. A significant change to Government policy or decision, for example of future decarbonisation of heat, brings a real risk to DNOs in the absence of the ability to be able to trigger such a significant re-opener. We therefore suggest that this is a company and authority triggered re-opener reflecting the DNOs position and insight into need.

[2] Para 3.106 Core document

We note Ofgem justification as to authority only is "*Ofgem to consider whether the Net Zero Re-opener is the appropriate mechanism to be used as well as if there is certainty over the change in question and its impact.*" Our view is this can still be fulfilled under a company and authority trigger where the authority can assess this through early dialogue with the companies and upon receipt of the application from the DNO, where evidence on the areas outlined will be set out.

Separately, we have major concerns over the current licence draft which has been shared for this condition which gives power to modify any other special condition. This effectively gives powers to Ofgem beyond that which we consider reasonable. This gives the effect to change any condition at any time in the price control and gives rise to a level of regulatory uncertainty which is not reasonable.

- **Materiality threshold:** We continue to propose that as all of the Net Zero Developments are outside of DNO control, that materiality threshold for this re-opener should be zero. This is consistent with other re-openers which are entirely outside of the company control such as Physical Site Security or Cyber.

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

We broadly welcome the introduction of the Strategic Innovation Fund (SIF) and note that the £450m value assigned to the Strategic Innovation Fund (SIF) is roughly aligned to that assigned to NIC in RIIO-1.

Given the significant challenges faced by networks as part of the Energy System Transition we expect the need for innovation to grow and SIF widens the innovation focus beyond gas and electricity networks, including other energy vectors such as heat. These factors have the potential to increase the number of projects applying for funding leading to greater competition and a greater risk of a project that would benefit ED customers not being awarded funding. Additionally, it is unclear as to how the funding will be split between the various Discovery, Alpha and Beta phases.

This uncertainty makes it difficult to comment on the amount proposed for SIF, but we do welcome an ongoing review to ensure SIF is adequately funded to deliver its aims throughout the period of RIIO-2. We note that there is no information on how the fund will be aligned to real annual cost changes across the ED2 period. We expect an increase to the £450m to reflect the real price challenges across the ED2 period and for this to be re-evaluated each year.

If the value of the NIA reduces following the planned NIA review in year 3 of ED2, then we would expect to see a corresponding rise in the value of SIF to ensure that we can maintain the level of innovation required to help meet the Net Zero targets.

The timing of funding of innovation projects under the SIF also needs to be considered, as this may create a barrier to development of certain projects. Under SIF, owing to the need to traverse through each of the Discovery, Alpha and Beta phases, the timescales for project development appear considerably longer than under NIC. If, due to the timing issue, interim funds need to come out of a licensee's central business plan to finance a project over a long period, there will be risks over the financeability of the project if it is uncertain when, or if, the money will be paid back at the end of the project. This is of particular significance after the first two years of RIIO-2, as projects are more likely to run into RIIO-3, where there is even more uncertainty if there will be a return on the investment in the project. The three-stage SIF process would appear to elongate the time it would take to get to the trial stage, requiring first successful transition through the Discovery and Alpha stages. The uncertainty this introduces may also put further strain on the viability of potential projects.

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

Please see our answer to Q9 and our response to ENWL annex question 7 as these areas are intrinsically linked.

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

We answer questions 8 and 9 (along with question 7 of the ENWL company specific annex) with one response as we feel that the responses are intrinsically linked.

We strongly disagree with the proposed approach to setting NIA allowances.

The commitment shown by Ofgem to unproven smaller scale innovation in ED2 is reduced with a decrease in real terms overall annual funding for DNOs in years 1-3, with £23m per year in ED2 compared to £30m per year in allowances for ED1.

This is coupled with the NIA allowance review in year 3 which brings added uncertainty over further innovation funding for the remainder of the ED2 period. Ofgem will need to provide DNOs with clarity in good time on what will happen from year 3 of ED2 because NIA projects will need to be all planned to finish then. Timescales and criteria for deciding the future of NIA funding are unclear at this point. Ofgem has indicated the three-year review is to afford it flexibility to align ED funding with future GDN and T innovation funding packages. This approach will lead to uncertainty and potentially reduce innovator appetite for low technology readiness level (TRL) ideas requiring multi-phase project development that are outside the scope of SIF challenges. If NIA should be continued after year 3, the two-year extension will only allow short targeted projects to be completed.

The staggered process employed to the transition of GD and T to SIF in RIIO-2 which is now intended to be implemented for ED2 could be replicated for any future NIA changes, therefore giving innovation stakeholders certainty over the 5-year ED2 period.

It is acknowledged in the ENWL Annex that in our case the methodology for benchmarking ED2 NIA allowance against ED1 leads to a reduction in annual NIA levels. This is despite being awarded 5/5 in the SSMD criteria.

We offered higher company contribution seeking to stimulate a larger NIA sum being proposed from Ofgem, essentially by offering to place more of our funding into innovation and take more of the risk alongside consumers, effectively proposing to back ourselves alongside consumers.

Since Ofgem hasn't responded to this as at DD we urge Ofgem to reconsider and further would no longer propose us having a higher company contribution in ED2 than that set for all DNOs. For ENWL, a 33 percent reduction in annual allowance will result in lost innovation opportunity and impact our ability to deliver value adding business plan commitments such as the Collaborative Innovation Scheme, the Innovation Oversight Panel or the 15 percent contribution we proposed as well as some of the proposed innovation projects. The narrowing of NIA scope for ED2 to concentrate on energy system transition and customer vulnerability may also exclude other valuable opportunities in the areas of flexibility and commercial evolution, whole system solutions and optimising of assets.

Ofgem’s stated policy position was that it was intended to set levels of NIA funding on the basis of the quality of a DNO’s business plan submission and the justifications for NIA funding set out in the business plan.

The approach taken to setting NIA allowances by benchmarking business plan evidence against the equally weighted five SSMD criteria (each equating to 0.1 percent of base revenue) has led to a weak dependency between business plan quality and innovation stimulus for ED2. Some network licensees will receive more money in cash terms than Electricity North West even though they scored lower against the SSMD criteria. This approach had led to the size of base revenue becoming the dominating factor which puts Electricity North West at a disadvantage as the smallest DNO. Additionally, this assessment method was not adequately articulated in the SSMD and had it been, we may have offered a different proposal in our business plan. We strongly recommend this approach is revised and a group level innovation allowance for companies is set, which would therefore create fairness for all customers regardless of company group size.

As a consequence of the proposed reduction in NIA funding in ED2 we anticipate there will a change in the type of innovation network companies will do.

Looking forward into ED2 network companies may focus Innovation funding away from areas which deliver long term whole system, customer and societal benefits to those of narrower and more short-term considerations focused on return periods. An example that may not be prioritised in this scenario is the work we undertook to successfully innovate to trial and roll out Smart Street. The Smart Street project has proven there are significant benefits to customers and NIA funding and its predecessor funding regime was fundamental in developing the component technology required to implement the Smart Street network control techniques. We foresee these type of forerunner projects that may benefit customers will have less precedence in ED2.

We face the same challenges as other DNOs in meeting the requirements of the energy system transition to Net Zero. However, the cost to innovate and deliver projects to meet the future challenges does not vary with the size of the company but with ambition. Throughout RIIO-ED1, we have consistently found our innovation ambitions constrained by our allowances. In a nutshell, we have more ideas than we have funding to support. While we worked with other DNOs to encourage them to address many of the issues we believed were important to support the transition to low carbon, it is not always practical to directly influence the work of other network operators.

We believe that we have excellent innovation credentials, delivering innovation into BAU as evidenced by our two LCNF Tier 2 projects now operating effectively in BAU: CLASS and Smart Street; the latter being rolled out currently with an expectation of being fully operational by 2023. We were the DNO that worked with Kelvatek on the development of its Bidoyng and Weezap devices that are now used in their thousands by all DNOs. This places us in a fantastic position to take on a greater share of the overall innovation effort. Our RIIO-ED2 Business Plan included a higher allowance for innovation than was provided in RIIO-ED1 to help us achieve the ambitious plan we set out.

There is a danger that reducing the NIA will decrease the amount of innovation, which in turn will result in less innovation by all companies and also lost benefits to customers and the environment. In reducing funding and introducing the SIF which is much more complex than the NIC, companies may not be able to influence the challenges sufficiently to help address any network-specific needs. Additionally, reducing NIA may result in resource limitations, restricting the number of projects that can be entered into the SIF process.

<u>Additional information – IMF</u>

Regarding the point raised by Ofgem in section 3.130 of the Core Methodlogy Document, the IMF (Innovation Measurement Framework) was developed by Baringa on behalf of the Gas and Electricity networks, and the Gas and Transmission companies will be reporting via this mechanism in RIIO-2. The IMF forms part of the "Energy Networks Innovation Process" which sets out a process for registering, monitoring and reporting of Innovation projects to which all networks have agreed.

At the recent Innovation Working Group Ofgem requested that DNOs should provide an example IMF report using data from ED1, including details of how the underlying benefits are derived. As we are still collating all the required IMF data in readiness of the agreed start ED2 implementation date, we require some additional time to produce the example data. The ENA is leading on this piece of work through the Innovation Managers working group, and we expect to provide an example excel file with a supporting commentary on the ENWL projects. Our current plan is to provide this information to Ofgem by 5 September 2022.

The IMF contains a benefit tracking methodology to report on a range of innovation outcomes, including collaboration and partnerships, the speed at which successful innovation is transitioned into BAU, and the benefits innovation has delivered for network customers. This is done in a transparent and consistent manner, using agreed benefits tables to populate a balanced scorecard.

In our business plan, we said that although it is not strictly necessary, we have already started to use this process internally following its publication in April 2021, to ensure we have it fully embedded ready for the start of RIIO-ED2. As such, we have been recording the ideas received and new projects registered since April 2021. The projects we have recorded are either still in progress or have closed down but require follow on work for a BAU solution and therefore are not delivering financial benefits yet.

It should be noted that not all innovation projects produce a solution which is financially quantifiable, for example improved forecasting techniques, improved business processes or better investment decisions. The IMF scorecard does allow us to show that these projects have successfully transitioned to BAU but will not show a financial benefit.

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 the 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.

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

We agree with the proposed approach for the Annual Environmental Report ODI-R. This report will enable us to keep stakeholders informed of progress and commitments during our journey to manage the environmental impact of our activities.

We note that Ofgem intend to provide guidance on the expectations for this report. It is critical that any guidance which DNOs are obliged to comply with in ED2 is available for DNOs to view well ahead of FDs and that this guidance is not developed by Ofgem in isolation. This should be able to be viewed in line with, and alongside, any drafting of associated licence conditions.

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

We do not feel that a mid-period review is required as the intent of this review should be covered by the yearly review. A focused mid-period review could be affected by short-term issues outside our control, such as supply chain issues seen during the COVID pandemic or Ukraine conflict. Also, several activities are in their infancy and as such the initial years will be spent increasing understanding and baselining, a mid-period review may not fully reflect this.

Should any mid-period progress review by Ofgem take place it is vital that this is sufficiently clearly scoped, well resourced, involves stakeholders, appropriately comprehensive and timely. If comparisons are going to be made between DNOs, work will be needed well in advance to move ED2 targets and measurements of progress to a comparable basis. Ofgem may want to be involved in this work as it could in certain circumstances require targets to be reset.

Core-Q13. Do you agree with our consultation position for the DNOs' EAP proposals in RIIO-ED2 as set out in this document?

We agree in principle with the consultation position for our Environmental Action Plan (EAP) proposals and believe that it matches stakeholder views on our EAP aspirations. Delivery of these proposals requires relevant funding and we highlight this in our response to question 106 where Ofgem's cost assessment and allowance allocation process fails to ensure that appropriate funding is allowed for the delivery of these key outcomes.

Please see below for specific requested clarifications:

DNO proposals for science-based targets (SBT) to reduce BCF

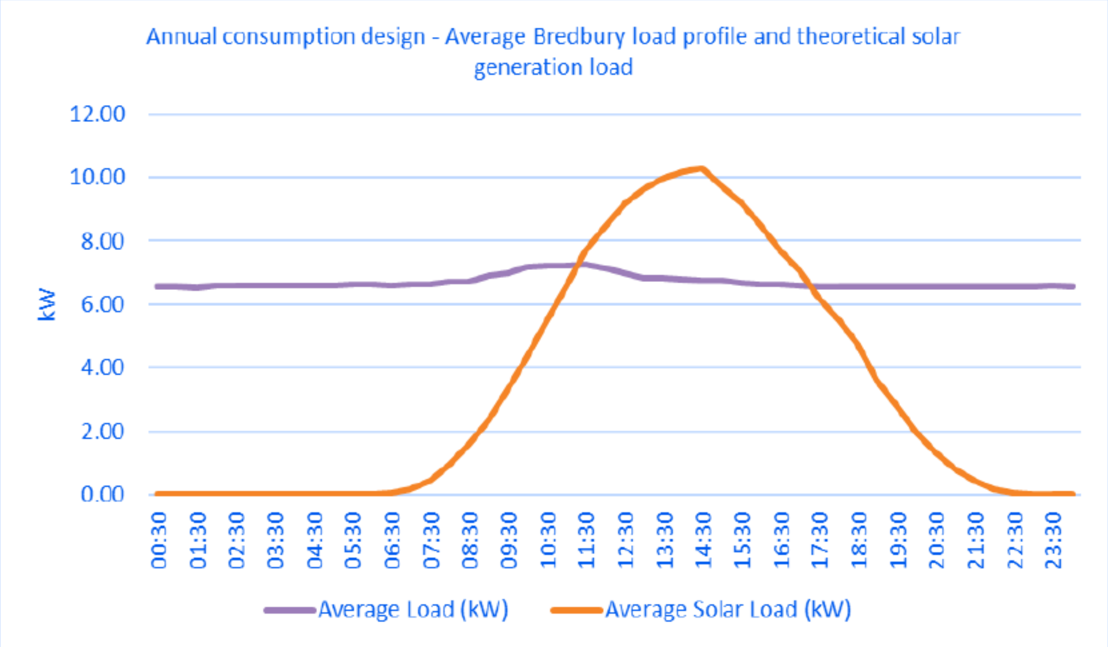
We submitted our SBT application for validation by the SBTi, committing to the 1.5°C pathway. This validation is due to start on 16 January 2023 and will take at least 30 days to complete. This application was delayed due to the SBTi not accepting new applications for part of 2022.

Reducing emissions from building energy use

Our EAP commitment is to convert one site to Net Zero Carbon (NZC) for each year of ED2. To reach this commitment, solar panels will be installed on sites; this falls under the '*energy management at licensee-owned sites'* status, as set out in paragraph 2.13.3 of the Prohibition on Generating Guidance (POGG). In line with paragraph 2.15 of the POGG, excess units generated will be exported to the grid to address a 'temporary surplus'. This is an annual consumption design for an owned asset, where annual consumption would align with annual generation to enable a site to become Net Zero. This approach also provides benefits with asset control, security, liability and access right benefits and was confirmed to fall within the POGG requirements in the correspondence '*Clarification regarding the Prohibition on Generating Guidance (POGG)*' from Alex Walmsley (Head of Distribution Flexibility & Enablers, Ofgem) sent on the 29 April 2022.

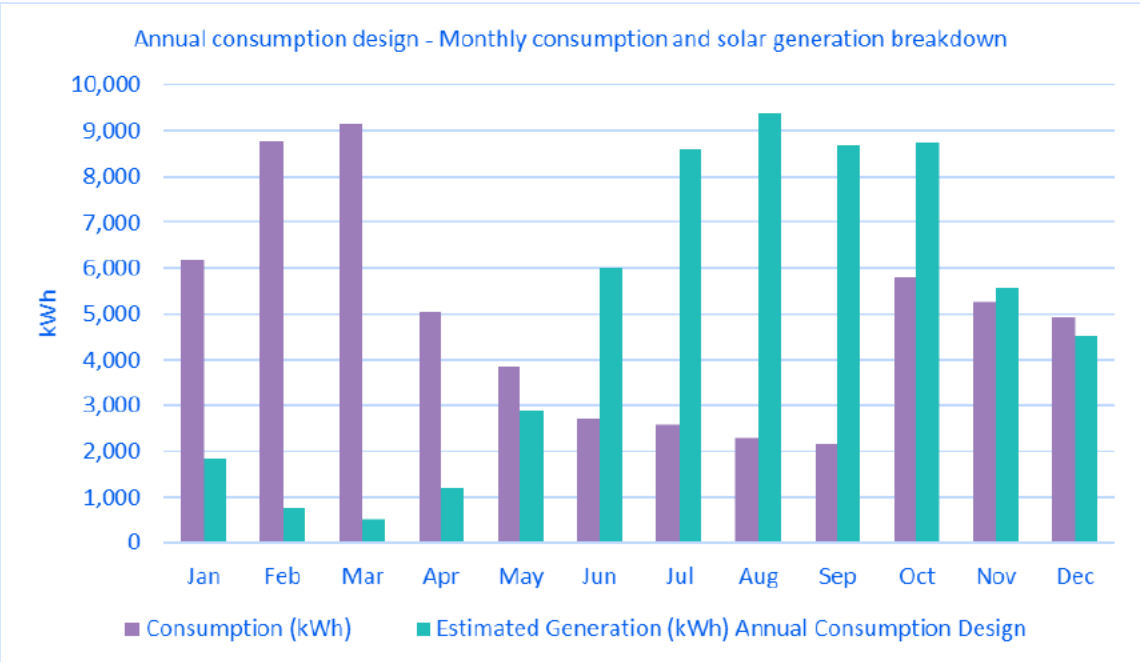
As an example, the annual consumption design for Bredbury grid substation, based on the [redacted] annual renewable energy generation target and assuming [redacted], has determined that the desired solar system size would be [redacted]. This would account for 100 percent of the annual generation target specified and would therefore enable the site to achieve Net Zero Carbon (NZC) status. However, this would result in [redacted] of renewable electricity being exported to grid per year (70.9 percent of annual solar generation). The average Bredbury load profile and theoretical solar generation load, based on an annual consumption design, is shown in the chart below. The average solar generation load is higher than the average site load from 11am to 5.30pm, but this approach ensures that the site achieves NZC status.

Figure 3: Annual consumption design – Average Bredbury load profile and theoretical solar generation load



The monthly consumption breakdown and anticipated solar generation is shown in the chart below. The solar generation significantly exceeds monthly consumption from June to October but is lower for the remainder of the year.

Figure 4: Annual consumption design – Monthly consumption and solar generation breakdown



The annual consumption design enables sites to become NZC in the most cost-efficient way.

Fluid-filled cables

The table 4 below shows the proposed length of cable expected to be replaced during RIIO-ED2 and the justification for this is covered in the Engineering Justification Paper Ref No NARM EJP 7 – 33kV and 132kV UG Cable Replacement which was submitted alongside our FBP.

Table 4: Proposed length of cable expected to be replaced during RIIO-ED2

Voltage	Length on Network (km)	ED2 programme	Proportion to be replaced
132kV	157.9	22.2	14%
33kV	232.3	49.3	21%
Total	**390.2**	**71.5**	**18%**

We will reduce our leakage rate to no more than 25,000 litres per year, a 30 percent reduction on our RIIO-ED1 average and less than 3 percent of our total oil in service as planned over the RIIO-ED2 period.

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

We agree with the proposal to withdraw the Environmental scorecard and its associated ODI-F for RIIO-ED2. At present, some of the potential items for inclusion are in their infancy in terms of reporting metrics or the ability to provide a baseline upon which to inform targets which could be financially incentivised as well as issues of reporting comparability and consistency which may not exist under a scorecard mechanism as currently proposed.

We believe that the reputational incentive (ODI-R) will drive all DNOs to deliver their commitments and progress made during ED2 in some of the newer areas will be able to potentially lay the foundations for consideration of introduction of a financial incentive for ED3.

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

We disagree with the proposed approach, but we agree in principle to its inclusion in the framework. We have specific and clear proposals on improvements to the design of the Environment Re-opener and set these out in three key areas:

<u>Scope:</u>

In our final business plan (FBP) we suggested that the scope should be:

"A re-opener for responding to new, or changes to, environmental compliance requirements that will materially impact companies' activities. The scope will be activities which relate to the decarbonisation of the networks and the wider impact of DNOs' activities on the environment."

Ofgem has not set out in DDs how our feedback has been considered in setting the scope for this re-opener. We maintain that our proposal is a more appropriate scope to reflect the uncertain nature of this area and urge Ofgem to make this change which we consider better reflects the policy intent.

It is important that the scope is not limited to purely new legislation, but also covers changes to enforcement practices, removal of derogations, and changes which are imposed by other external bodies. The requirement to remove PCB contaminated equipment, and the change to SF_6 legislation are just two examples that we have seen in recent years that have caused Ofgem to consider the need for such a re-opener, neither of which are new legislation.

We also consider that the re-opener should not be tied to only those activities that are contained within the EAP. The EAP has been specified by Ofgem based on current, known activities. If the re-opener was limited in such a way to only consider such known activities, it would preclude any new requirement that is not already in place and therefore not in the current scope of the EAP, appearing to us to be irrational. For example, if there were a ban on the use of creosote on wood poles in the way there has been for PCBs in transformers, then this would be a brand new activity, out of the current EAP scope. We do not believe that it is the intention of Ofgem to exclude a new decarbonisation or environment-based activity purely because it was not already captured within a company's EAP in 2021.

To resolve this issue, we have suggested to the licence drafting working group that the scope be drafted as:

"Where there are new or amended legislative or regulatory requirements set on the licensee by any external regulatory body that relate to its Environmental Action Plan Commitments or other environmental obligations during the Price Control Period."

<u>Materiality threshold:</u>
As this re-opener is being developed to deal with an uncertainty related to external change and mandated compliance wholly outside of DNO/management control, we also proposed that this re-opener should have a zero financial materiality threshold, which is in line with the equivalent arrangements for Cyber and Physical Site Security where the same principle of cost being driven by external government or regulators own decisions leads to zero materiality reopener thresholds.

<u>Authority only trigger:</u>
We do not agree with the proposal that this re-opener can only be triggered by the Authority and not DNOs and urge Ofgem to consider that this should also be a DNO triggered re-opener.

It is unclear why Ofgem consider that this should not be able to be triggered by the DNO, as the DNOs are best placed due to monitoring the landscape in which we operate to understand how and when compliance requirements will change. They are also best placed to understand the impact and therefore potential need to submit an application under the re-opener. DNOs regularly work with the Environment Agency and other enforcement bodies and will almost always be aware of such new changes ahead of Ofgem becoming aware. DNOs are best placed to understand materiality and impact of any changes, and as with any other potential re-opener application will ensure that dialogue with Ofgem is opened at the appropriate time.

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

We agree, and we welcome the proposal of Ofgem to accept a mechanism we proposed more broadly as common for the sector.

It has been noted the DD sets out "*So far, the DNOs have submitted a variety of proposals to meet their compliance obligation and address this uncertainty. We request that the DNOs provide further data* *and evidence for the costs and volume of work as part of their consultation responses. If this data and evidence can support the design of a robust volume driver, we propose to confirm the design in our Final Determinations, including the form and granularity of the mechanism to reflect the unit rate(s) and possible upsizing requirements. If the DNOs do not provide sufficient data and evidence, we propose to set an evaluative PCD to ensure appropriate delivery."*

We are unclear what additional information Ofgem is requesting given the amount and volume of detail we have provided in our FBP including in our UM design within our UM annex and in our PCB EJP. To that end we asked an SQ (ENWL030) and based on the response from Ofgem[3] we have not included any additional information in this response and look forward to working with Ofgem and the sector in considering any additional data requirements needed to supplement the FBP submissions and will provide this when formally requested.

3 Supporting a smarter, more flexible, digitally enabled energy system

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

We agree in principle with the proposal of implementing the licence condition assuming it is proportionate to the need. DNOs must continue to be part of the detailed definition of the condition at the licence drafting stage and the ongoing development of data and digitalisation guidance for network operators.

Our transition to Net Zero requires new systems and processes to operate energy networks in a more sustainable future. Investing in digitalisation gives us the ability to meet customer and stakeholder demands on the network and supports the journey to Net Zero, while further improving cyber protection and opening-up our data and increasing transparency.

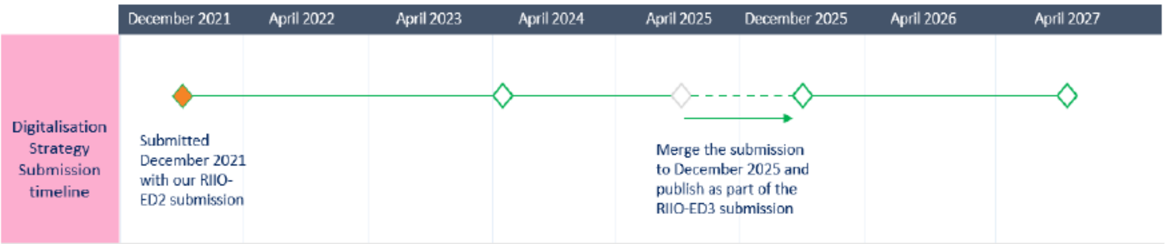
We have an ambitious plan that puts our customers and stakeholders at the heart of everything we do, and digitalisation is essential to achieve this.

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

We agree in principle as we support cross sector coordination, and the staggering of the publication of Digitalisation Strategies allows best practice sharing between sectors. Dialogue and learning will be stimulated by reflecting on and learning from gas and transmission digitalisation strategies and the feedback from their stakeholders.

In FY26 we would propose to have a merged submission of the Digitalisation Strategy, combining the submissions for April 2025 and December 2025 (as shown in the diagram below), as part of our RIIO-ED3 proposal submission. If this submission is not merged, due to the timing of the schedule we will be required to publish two strategies within the same year which does not seem efficient, necessary, nor in stakeholders' interests.

Figure 5: Proposed timeline for Digitalisation Strategy submission



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

We are broadly supportive of the inclusion of a new Digitalisation re-opener. We agree that the digital energy landscape is fast moving and as such there is a strong likelihood that DNOs will be given new obligations on data and digitalisation that are not built into existing ED2 business plans. We therefore welcome the foresight of Ofgem in including this uncertainty mechanism in the framework.

However, the proposed materiality threshold of 1 percent of turnover however is too high. The rapidly changing data and digitalisation landscape requires DNOs to be more responsive. As the majority of changes that would trigger the Digitalisation re-opener are driven by government or regulatory change, then we consider that this re-opener should have a zero materiality threshold in line with other re-openers which are outside of DNO control and compliance driven in nature. Two examples would be changes driven by Ofgem Significant Code Reviews such as Market-wide Half-Hourly Settlement (MHHS), or by revision to the Ofgem Data Best Practice (DBP) and Digitalisation Strategy and Action Plan (DSAP) guidance. To limit necessary data and digitalisation improvements by adding a materiality threshold risks limitation of consumer and wider whole system benefit which we do not think is the intent of Ofgem.

Major digitalisation of systems required to facilitate MHHS, new capability such as Technology Business Management (TBM) and an analytical Digital Twin are not currently in our plans nor is any significant investment in machine learning or artificial intelligence.

Additionally, we are currently planning to take our Enterprise Resource Planning (ERP) SAP ECC6.5 into RIIO-ED3, but if we are not able to maintain appropriate support arrangements, we may need to implement a new platform in RIIO-ED2.

The cost assessment used for DD will only enable investment in baseline IT and OT initiatives and will hinder investment in more transformational areas such as data and digitalisation and DSO implementation. We have completed detailed scenario planning across our RIIO-ED2 investment portfolio and the main investment area adversely impacted is Data, Analytics and Integration which we will be forced to treat as a re-opener. See our response to the cost assessment questions for a fuller articulation of our concerns.

Our proposed investment in Data, Analytics and Integration reflects our data strategy and supports the implementation of the five recommendations of the Energy Data Taskforce, Ofgem's Data Best Practice Guidance and the seven digitalisation principles. To transition to Net Zero, access to reliable quality data is essential for the work by our customer services team and field workforce as well as other existing and new industry organisations, and to business and domestic customers. Without this investment, we will not be able to implement many of the EDTF recommendations, Ofgem's Data Best Practice guidance, nor any of the Data and Digitalisation Deliverables.

Other areas include transformational investment in low-code platforms and Ofcom driven change such as decommissioning the 3G network, and the re-allocation of spectrum in the 1.44 GHz band for other uses. This impacts ENWL as many of the point to point operational telemetry links in rural areas (45) currently reside in the 1.44 GHz spectrum.

We disagree with the single re-opener window, and our proposal is that re-opener windows apply in years 2 and 4 as this gives the opportunity to respond quickly to new challenges such as these.

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

We would like to understand more and have greater detail on how Ofgem envisage utilising the enhanced reporting for spend and investment, in IT/OT Digitalisation Strategy and Action Plan investment proposals. It would be good to have clarity about how this will involve TBM and whether the use of TBM is proportionate.

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

Whilst we agree in principle, this is on the basis that we will receive an appropriate level of allowance for this, determined by the scope of TBM Ofgem requires us to have and Ofgem's detailed requirements. We have not included a costed implementation of TBM within our Digitalisation Strategy and Action Plan in the Final Business Plan as it was not a requirement at that time.

We sought further detail on the intent for TBM via a supplementary question (SQ[4]) and in the response from Ofgem, we understand their view is that the cost of implementing TBM will 'not be material as utilisation of TBM will simply be a presentation layer on spend'. However, based on our conversations with external IT analysts, and also with the market leading TBM provider, we are concerned that there will be material costs to implement TBM capability. Furthermore, Ofgem said in their SQ response to us that the ED TBM guidance 'will likely look like' the ESO guidance.[5] Our review of the ESO TBM guidance document is that the efforts to implement TBM are not trivial, and we are also concerned at the level of development required for us to be ready to submit re-opener submissions, digitalisation action plan and digitalisation strategy updates, and ED3 business plans supported by a TBM format.

We want to ensure that when TBM is implemented it is done to an appropriately high level of quality, and in a way that is integrated into our systems. This will certainly require us to invest in our systems, but without sufficient detail on how TBM should be implemented, we do not think we are in the position to say for certain whether the spend required to do this will be material or not.

Modernisation and reducing the burden of reporting to a level that is more proportionate would be welcome. However, we need to ensure that we don't increase complexity and the overhead by introducing TBM into the RIGs/RRP process, unless Ofgem is considering expanding TBM to cover all DNO activities. From a digitalisation perspective we would be keen to align IT investment planning with the RIGS/RRP timelines reporting for Ofgem, though Ofgem should be mindful we see a risk of our IT investment processes being heavily driven towards Ofgem's own approvals processes via IT related reopeners.

It is important that whatever approach Ofgem chooses to take, there is consistency for DNOs on their reporting requirements cross cyber, digitalisation strategy, ED2 re-openers and for RIIO-ED3 so that the reporting burden is minimised, and so that there is consistency and accuracy across reporting.

[4] ENWL015
[5] www.ofgem.gov.uk/sites/default/files/2021-11/ESO%20Business%20Plan%20IT%20Investment%20Plan%20Guidance.pdf

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

We agree in principle and support the simplification of reporting processes and increasing the level of digitalisation across the energy system and unlocking the value of data. It is important that any improvements to the reporting processes are proportionate, funded and deliver clear benefits to customers and energy networks stakeholders.

It is important to understand the benefits as well as the costs; better use of the data and better leverage of the data by Ofgem is assumed, but it is unclear what the benefits to DNOs will be. This modernisation must deliver quicker, cheaper, easier reporting with increased level of automation and appropriate granularity of data otherwise we are passing inefficiency onto customers.

Costs to support the modernisation of regulatory reporting will need to be appropriately funded, either through baseline allowances, or a mechanism as Ofgem determine appropriate.

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

We agree in principle, subject to funding and a clear benefits case, detailed scope and clarity on resourcing levels. Delivery in Y3-Y5 is more appropriate than at the start of ED2 so that any changes to requirements can be taken into account. This is based on our current view of RIIO-ED2 and we would need to reconfirm our support nearer to the proposed implementation date. Progress should be made first on RIIO-T/GD2 and we suspect the project should be undertaken as an all sector project on the same timeline with Ofgem.

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

Ofgem's acceptance of the DNO's DSO strategies with substantial changes to their funding is surprising as there are two distinct models for DSO being carried forward into RIIO-ED2 with one organisation adopting a legally separate DSO model and the other DNOs a version of an integrated DNO/DSO model, albeit with the appropriate control measures to manage conflicts of interest and operate as a neutral market facilitator.

We understand that this keeps the which model question open until more information is available to review but is this the right way to gather evidence on structural reform as the debate continues through the Call for Input on the future local energy institutions and governance continue in the background? We also question whether it is appropriate to burden a specific group of customers with the additional costs of legal separation to test a variant of Framework model 2, the independent DSO model in RIIO-ED2, whilst not taking into consideration the interplay with other local institutions. Our response to the Call for Input on Future local energy institutions and governance shows that we are engaging with the process laid out by Ofgem and we have made constructive suggestions on how the industry could be shaped to better support local stakeholders to achieve Net Zero. We will continue to support Ofgem through the Call for Input discussions until a decision is made.

We agree that the proposed DSO incentive will drive the DNOs to deliver the DSO roles and responsibilities. But as a new incentive it may take a few years to bed in the processes before we would expect to see the results expected by Ofgem and there are a number of challenges with the incentive. Particularly how it will work is unproven, comparability across DNO groups and licence areas will be a challenge, how stakeholders view the incentivised outcomes etc are all unclear. Therefore, Ofgem should be careful with the strength of this incentive. In our view reputation is a weighty consideration in respect of DSO activities so financial incentive rewards do not need to be supercharged on top as we expect strong focus on DSO anyway. We will engage with the working group through summer and autumn to assist Ofgem to develop a fair, consistent and robust framework for the DSO incentive.

Yes, we see the benefit of having a broad set of measurements and evaluation mechanisms but are concerned about its pragmatic application and the weighting between the three elements that make up the incentive framework.

Our comments fall into four broad areas:

- Stakeholder survey,
- Weighting of components,
- Operation of panels, and
- Potential cross-over between elements.

Stakeholder Survey

Firstly, we supported Ofgem's move from one 'killer' question to a broad set of questions for the stakeholder survey and at the time highlighted our concerns about obtaining feedback from a representative sample of customers and stakeholders for each question, and this remains a concern.

When engaging with a wide range of customers and stakeholders on the development of potential DSO performance metrics it was apparent that the majority were unaware of the transition to DSO and the split between DNO and DSO responsibilities. It is likely that this situation will continue for many years to come which could prove detrimental to obtaining robust and truly representative feedback from the stakeholder survey element of the incentive framework.

We are not proposing that the stakeholder survey should be removed, as it will provide us valuable feedback on how customers and stakeholders perceive our services. But we do question the use of a target defined by proxy from the ESO, where all the ESO's customers would have known about the separation from NGET and the roles and responsibilities of the new entity. This is not similar for the DSOs that arguably are still DNOs with defined DSO roles, responsibilities and activities. We propose that the stakeholder survey is trialled for several years to set a real and tested target value and during this time the mechanism for reward/penalty is switched off, until defined.

Further, we propose that a threshold is set at the sample of responses per stakeholder question which must be more than 30[6] if this is to be incentivised. Results with less than 30 valid responses should be treated as reputational only.

Weighting of components

Secondly, the weighting between the elements appears to be heavily biased towards stakeholder assessment of our performance and although it feels appropriate that the majority of the evaluation should be via performance panel and the stakeholder survey as compared with the performance metrics but at 80 percent this weighting feels unwarranted.

As shown in table 5 below we therefore propose that the weightings are rebalanced.

[6] Based on central limit theorem (CLT) widely referenced in statistics. CLT states that the distribution of sample means approximates a normal distribution as the sample size gets larger, regardless of the population's distribution. Sample sizes equal to or greater than 30 are often considered sufficient for the CLT to hold.

Table 5: Proposed weightings

Incentive element	Draft determination	Proposal	Reasoning
Stakeholder survey	40%	30%	This is brand new, with a target ported from another process
Performance Panel	40%	30%	This is a subjective method of evaluation and so should be less relied upon
Performance Metrics	20%	40%	These are key measures that are important to deliver. It is actual delivery that should be the largest portion of the incentive reward (not perception of delivery as per the other two categories)

This provides a greater balance between the evaluation of stakeholders and third parties on the activities delivered by the DSOs and the delivery of measured outputs by the DSOs.

<u>Operation of panels</u>

We continue to view panels as an aspect of incentive mechanisms that can be prone to risk resulting in poor and unintended consequences for consumers. It is vital that lessons learnt from the use of panel assessment in ED1, in our experience under SECV, are fully applied to any panel approaches if these are taken forward for ED2. We note subjective panel assessment is currently proposed for DSO in ED2. Particularly, guidance for scoring must be properly maintained and updated throughout the relevant period[7] to reflect what the evolving requirements are under the incentive. This ensures Ofgem and consumers are most able to benefit from steering the standards upwards and locking in what good looks like, spreading the benefits to all consumers nationwide. Ambiguity around what the requirements are or around the standards moving but not being documented from year to year does not benefit consumers as companies are less robustly able to develop to meet the incentivised outcomes Ofgem is seeking.

Panels need to ensure that their members are clearly without any conflict of interest. We know Ofgem supports this, but we are concerned about perceived and potentially real conflicts of interest as we look back for potential lessons learnt in ED1. For example should a panel member be heavily involved in the activities of one or more DNOs, such as customer and stakeholder engagement and on work to address vulnerability, it is not sufficient in our view that they are not involved in scoring those companies they are directly involved in, but it is vital they are not scoring any other companies because of the potential for a perception of bias towards what good looks like being from the activities they have been involved in at certain companies and not others. Further the involvement of anyone on a panel who then advises or guides or otherwise provides feedback directly or indirectly to only certain companies (e.g. joins their stakeholder panel) and does not join other companies' panels, tilts the incentive benefit towards those companies who may even indirectly get a benefit from the input shaped by someone who is aware of all the inside information around that incentive. For these reasons even more, effective management of perceived or real conflicts of interest for panel members need to take place for ED2.

[7] SECV Guidance last updated December 2018

Potential cross-over between elements

Lastly, there appears to be areas of cross-over between the questions in the stakeholder survey and the evaluation areas being considered by the performance panel. This was a concern raised by Ofgem in the DD consultation to ensure that the DSO are not penalised or rewarded in the same area. The table 6 below shows these.

Table 6: Potential cross over between incentive elements

Theme area	Concerns
Data provision	Question 2 of the stakeholder survey also covers the area of data and information provision. How will these two review areas ensure that there is no cross-over?
Flexibility market development	Question 3 of the stakeholder survey looks at the area of flexibility services and processes data and information provision. How much of this is a cross-over with the scope of the performance panel?
Options assessment and conflict of interest mitigation	Stakeholder survey Q4 also looks into how the DSOs are managing conflicts of interest? How will the two processes ensure that there is no cross-over?
Distributed energy resources (DER) dispatch decision making framework	Stakeholder survey Q4 also looks into the decision-making frameworks of DSOs. How much of this is a cross-over from the stakeholder survey Q4?

Core-Q25. What are you 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.

We are broadly comfortable with the framework proposed by Ofgem for the DSO incentive notwithstanding our proposals on weightings above which are crucial, including the inclusion of outturn performance metrics and RRE. There appears to be a bias towards flexibility market development where six RREs are suggested whilst in other categories only two RREs are proposed. Although we recognise the importance of flexibility market development we suggest that only three to four RREs should be tracked for each area.

We note Ofgem has proposed five reporting indicators (in DDs) within the volume drivers for load related expenditure and suggest it is appropriate to include LCT growth and the Board Measure of Load Growth as additional RREs to provide the societal context for the performance panel.

We add that the cut to our funding request for the LV monitoring programme as a result of cost assessment will have a significant impact on our ability to deliver our DSO strategy, and a resulting impact on the metric for monitoring LV network visibility and the knock-on consequences for the load related metrics also. We provide further views on the approach to cost assessment in question 79 of this response.

Although we have specific comments on the details of definitions and reporting specifics for the outturn performance metrics and the RREs are best dealt with through planned working groups between now and September 2022. It is vital that Ofgem consider and act upon input/feedback it receives from DNOs and stakeholders within working groups and any other associated communications such as in this area.

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

We have concerns that as currently proposed the wide scope of the re-opener is an unacceptably high risk to the DNO business. We do however welcome in principle the development of a DSO re-opener mechanism as a means to amend the roles and responsibilities of the DNOs with regard to their DSO obligations.

Therefore, we suggest that the scope of the re-opener is limited to amending only DSO costs, obligations and incentives and/or consequential implications to other areas of the price control from DSO changes. As we shared in our FBP submission, we consider it prudent for Ofgem to include a DSO re-opener within the framework based on the knowledge that work is currently underway to look at future governance arrangements for DSO.

We do have comments on three elements of the DSO re-opener as detailed below:

<u>Scope</u>

The DD position appears to provide Ofgem with the power to change *any* cost, output or incentive unfettered. We consider this a wholly inappropriate broad scope and the DSO re-opener should be limited to those costs, associated costs, outputs and incentives related to DSO activities only in ED2. Our recent response to an Ofgem RFI indicates examples of the costs impacted in this area, this includes consideration of systems and processes impacted.

<u>Trigger</u>

The trigger is unclear within the DD and therefore further detail is required to allow us to comment on this in a more informed manner. We note, however that there must be a clear decision point based trigger, that has been fully consulted upon, including with an appropriately robust impact assessment.

Whilst we do not support Authority only re-openers as a general principle, we recognise that this re-opener will only be used to enact the outcome of an Ofgem review on governance and institutional arrangements and therefore in this unique situation it may be appropriate to be an Authority only trigger.

Ofgem must consult on any intention to trigger this re-opener and the scope of what this might cover. In that consultation Ofgem needs to set out its proposed timescale and any clarity on requirements for the DNO as well as to carefully consider any responses it receives before decisions are reached. Companies need to have sufficient time to gather the relevant information to prepare and submit a robust re-opener response to Ofgem for its consideration. Any implementation of re-opener decisions needs to consider timing of implementation and practical considerations for the companies. Ofgem may wish to re-consult with DNOs and other stakeholders on implementation issues.

It is essential that any changes arising from the re-opener should go through the licence statutory consultation process. We would not support that this is done by directed change to our licence.

<u>Materiality</u>

As this re-opener is being developed to deal with an uncertainty related to external change outside of the DNO/management control we do not consider that the common materiality threshold should apply, and we therefore propose that this should have a zero-materiality threshold aligning its treatment with areas such as Cyber and Physical Site Security.

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

We welcome the clarity provided by Ofgem in the DD on the proposals to produce a whole systems strategic plan. Our concern is that between the new obligations in the Whole System Licence condition, the revising of the format of the Long-Term Development Statement and the requirement to publish a Network Development Plan as defined by SLC 31E, an additional whole systems strategic plan has the potential to separate inappropriately these interlinked obligations causing confusion.

Continuing to add new licence obligations on top of existing requirements without thorough review and consideration is sub-optimal and could become an unnecessary administrative burden, whereas reviewing the requirements at a holistic level provides the opportunity to build upon the existing interlinked obligations driving a clear set of responsibilities and outputs.

We suggest that Ofgem takes the opportunity to simplify and clarify the obligations across these areas ensuring that there are clearly defined obligations that operate in a holistic manner taking into account existing processes, seeking that requirements are cohesive and not unnecessarily complex or fragmented.

As a minimum, any new licence obligation should also be consulted on for all other Ofgem regulated bodies who form part of the whole system strategic planning activities. The ED sector alone should not have obligations that need other licensees to participate in the delivery of whole system outcomes, and these licensees must have the relevant and appropriate enabling licence obligations of their own.

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

The key is that the information is easily accessible and easy to use. We would expect to have a data repository that provides the ability for stakeholders to retrieve the data/information they wish to see, but also has the ability to use APIs to retrieve data.

Our standard publications of existing and future network needs e.g. our DFES forecasts, heatmaps and signposting of network needs would be displayed visually and geographically to aid understanding of local and regional differences.

We expect our Network Development Plan to be digital and online mapped onto our GIS so that stakeholders could look up locations and other details. In summary the digital tools that could be used to support the whole system strategic plan are:

- **Data Platform** – cataloguing, processing, analysing and sharing data that is relevant to whole system planning and operation
- **Historian services** – provision of full history of whole system events and conditions
- **Visualisation** - Online mapping of our network development plan, DFES and Heatmaps, and
- **Data Services** – automatically requesting and consuming relevant datasets.

4 Meet the needs of consumers and network users

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

We have some concerns based on the proposal in the DD and additionally we are unclear on the logic of the Ofgem calculations used. We cover our concerns in the distinct areas below:

Targets and Target setting

For ED1, a common target was set for the three areas surveyed as an independent benchmark (based on CSI) as the parameters of the incentive. If Ofgem intends to use the ED1 performance as the basis of setting targets, then we would expect these to be calculated separately for each of the three areas. There are different levels of performance for each of the three areas and it would seem more logical to assess these separately and set targets accordingly; this would also be consistent with the approach taken in GD2.

Whilst the use of the most recent years data would normally seem a sensible approach, we are concerned that this approach is not appropriate here. There is a noticeable increase in scores given for the years 2019/20 and 2020/21 which we believe is in part attributable to customer reaction to key workers continuing through the COVID-19 pandemic. We observe a reduction in the scores in 2021/22 but appreciate that this will only be recently visible to Ofgem as part of our July Regulatory reporting return. Our concern therefore is that this increase in performance, influenced by a wider set of circumstances, is artificially increasing the target scores for ED2.

We suggest that either these years (2019/20 and 2020/21) are removed from the calculation or that all ED1 performance is used in the calculation i.e. all seven years for FD. We would definitely expect the data for 2021/22 to be included in the calculation of the final figures at FD rather than it being left out by Ofgem. Prior to DD the Ofgem stated principle in working groups and SSMD has been to use the latest data in the setting of targets for ED2 and this would include 2021/22. Our view is that Ofgem would be wrong not to include this and should do this as a matter of principle. Not to use latest data consistently would be wrong.

Deadbands

We support the introduction of deadbands in this context and targeted area, but have concerns that the proposed approach is significantly more onerous than the equivalent approach in GD. In GD the approach for calibrating the start of reward/penalty was ± 0.5 Standard Deviation (SD) applied to the average performance and ± 1.75 SD to set the maximum reward/penalty. It is unclear why a more onerous approach is being applied to rewards for DNOs and clear justification is needed for such a deviation away from an approach based on Ofgem regulatory precedence.

It appears that the good performance across DNOs is now resulting in more challenging targets for ED2. This is creating a perverse situation where performance has gone beyond the maximum reward target of 8.9. This enhanced performance gains no extra reward in ED1 yet is being used to set the reward and penalty thresholds for ED2. This is particularly acute when considering how this is applied to penalties as the scores above the maximum reward have increased the average and therefore the reference point for the deadband. For instance, for General Enquiries the average over the six years is 9.15 but would have been 8.86 if no score went over the 8.9 maximum reward threshold.

We would therefore suggest an asymmetric deadband approach is applied, consistent with that used for Unplanned work in GD. This would avoid the situation where DNOs could be in penalty for what would be considered excellent levels of customer service in any other industry. It also recognised that there is likely to be significant change in the mix of activities that go through each of the surveys in ED2; particularly General Enquires that will see a greater proportion of LCT work than that experienced in ED1.

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

Yes, the collaborative approach will drive best practice sharing across the industry, but we would need to understand any impact on the framework.

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

We disagree with the proposed target and the maximum penalty score.

Customer behaviour trends for the past two years since the pandemic have shown an increase in complaints across all markets and therefore we consider the 2.8 metric score is unrepresentative and calibrated incorrectly placing an unrealistic challenge on the sector. In its most recent report[8], the Institute of Customer Service identified the highest levels of complaints it had ever reported. To address this, we believe that a deadband applied before penalty would allow for this adjustment of behaviour and any future increased reliance on electricity, consistent with the approach taken for other areas such as BMCS.

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

As discussed and agreed with Ofgem through bilateral engagement, our plan should not be adjusted as we have not included any direct funding of these activities.

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

We support the desired intent to have a more mechanistic approach and to introduce independent assessment as we believe that this will bring more consistency between DNOs and across the sector more broadly.

Our main areas of concern relate to the metrics and weighting and to how the targets will be derived.

In terms of the metrics and weightings, we think that assigning equal value to the social value delivered and the satisfaction of customers that have received those services is not appropriate. We think a much higher weighting should be placed on the social return delivered through the NPV calculation subject to this being recalibrated for ourselves to be consistent and comparatively applied across the sector. We would go so far as to suggest that the CSAT score should just be a reported metric rather than financially incentivised.

We welcome the commitment from Ofgem to *"…work with all DNOs to ensure that the DNOs' targets are complete, comparable and independently assured, using the common Social Value Framework ahead of Final Determinations."*[9]

[8] UKCSI - The state of customer satisfaction in the UK - July 2022
[9] RIIO-ED2 Draft Determinations ENWL Annex 2.9

We also note that the detail of the ODI is being developed after FBPs have been submitted by DNOs. As this element was not part of the Business Plan Guidance, our proposals relating to supporting customers not being left behind did not have explicit commitments that an SROI calculation could be applied to. Given this timing issue, we are keen to work with Ofgem so that suitable targets can be developed and this part of the incentive available to us.

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 set out our response to this questions into the areas of PSR reach, Support Services and Support Services – CSAT below:

PSR reach

We set our targets for PSR Reach in our FBP based on extensive stakeholder research that balanced improving the reach and the costs of doing so traded off against support for fuel poor customers. This resulted in a baseline target of 60 percent and a stretch target of 80 percent.

To put in context, less than 80 percent of the eligible population in the UK are vaccinated for COVID 19 and the annual uptake for the free seasonal influenza vaccine uptake amongst GP Patients in England is less than 60 percent. The table from government data below, shows the regional differences in uptake of the influenza vaccine. In all the categories, the North West is seventh or eighth in terms of ranking and always below the national average which demonstrates the regional variation.

Table 7: Regional differences in uptake of the influenza vaccine[10]

	65 and over		Under 65 (at-risk only)		All Pregnant women		50 to under 65 years and NOT in a clinical risk group		All aged 50 to under 65 years	
	% Vaccine Uptake	Ranking	% Vaccine Uptake	Ranking	% Vaccine Uptake	Ranking	% Vaccine Uptake	Ranking	% Vaccine Uptake	Ranking
North East	84.8	2	56.1	2	42.9	2	50.5	2	57.3	2
North West	81.3	8	52.0	8	36.0	7	43.4	7	51.3	7
Yorkshire And The Humber	84.0	3	55.2	3	40.4	4	49.3	3	55.7	3
East Midlands	83.2	4	55.0	4	40.4	5	47.8	4	54.8	4
West Midlands	81.4	7	53.0	6	37.1	6	44.9	6	52.3	6
East Of England	81.4	6	52.3	7	35.2	8	43.3	8	50.3	8
London	70.1	9	42.8	9	30.6	9	29.8	9	38.2	9
South East	82.8	5	54.8	5	41.1	3	47.3	5	53.9	5
South West	85.2	1	58.2	1	43.7	1	53.5	1	59.3	1

We therefore think bespoke targets should be set for DNOs rather than a common target. Each DNO developed its targets in conjunction with its customers and stakeholders and therefore the incentive should be based on those targets. Setting a common target ignores the different levels of ambition sought by our stakeholders, the regional specific conditions (such as the proportion of hard to reach and the propensity to take up services) and the level of funding requested to meet those targets.

Had we been granted the allowances requested then we could have accepted that the 60 percent target was funded in baseline allowances and it would have been appropriate for this to be in the deadband. However, with funding cut by 18.6 percent, this reduces our ability to increase the PSR reach to our target. The 75 percent target to start earning reward is therefore calibrated too high with the link between service and cost being disconnected. Our stretch target of 80 percent would have

[10] Seasonal flu vaccine uptake in GP patients: monthly data, 2021 to 2022 - GOV.UK (www.gov.uk)

been within the reward band but with the 18.6 percent reduction in funding then we think this is unachievable.

Whilst we recognise incentive reward needs to be challenging, to have any incentive properties it needs to be stretching but achievable and considered explicitly or implicitly with the cost assessment challenge that has been placed on the sector. Our concern is that the 75 percent and 90 percent thresholds are too high and therefore become unrealistic to achieve for the funding which undermines the whole purpose of this incentive. We therefore would propose that should a common target be maintained; the incentive reward window is recalibrated with reward earned between 70 percent to 85 percent.

Support services

We welcome the inclusion of Social Return on Investment (SROI) and the use of bespoke targets. We welcome the intention of Ofgem to "*work with all DNOs to ensure that the DNOs' targets are complete, comparable and independently assured, using the common Social Value Framework ahead of Final Determinations.*"

We note and have real concerns that there are very different levels of NPV being set for each DNO and therefore are concerned that there are differences in approach and utilisation of the SROI model. Our NPV value is the highest of any DNO group, despite holding a single licence. We believe that this puts us at a serious detriment to other DNOs in relation to the cuts in funding proposed by Ofgem and ultimately, we are being penalised for our level of ambition when compared to other DNOs.

All things being equal all other DNOs would need to invest relatively small sums of additional money (over and above their allowances) in order to generate an extra 20 percent of NPV and therefore earn maximum reward. For example, one DNO would only need to increase its NPV by £1.9m of social return to earn maximum reward whereas we need to generate £12.2m extra social value.

Ofgem needs to consider how it calibrates reward thresholds between DNOs considering the level of ambition shown and the connection between costs and quality of service where these have not been explicitly or implicitly controlled for within the cost assessment process. We set out more detailed views on this in response to question 106.

We are supportive of the jointly commissioned work by DNOs to engage an independent company to review the use of the social value model and make recommendations to ensure greater consistency.

Support services CSAT

We disagree with the proposal to introduce CSAT targets for LCT and fuel poverty support services. We understand the principle behind the measure but challenge whether it needs to be a financial part of the incentive.

In terms of the targets, we don't have sufficient data for current baseline performance in this area. We do not think that applying scores that are derived from long established mechanisms for BMCS are appropriate as BMCS performance has improved over many years and the development of clear rules and exclusions form part of the mechanism. Expecting DNOs to perform at this level for a new incentive is wrong and unrealistic, particularly setting a maximum reward target that is higher than that proposed for the long established BMCS. Many of the customers who will use this service have multi-faceted challenges in their lives which could impact their responses and the uptake rate could create instability in this metric. Many of these will be hard to reach customers and therefore may score us less well as they are not immediately receptive to the services.

Too high a target for these support services may undermine the intention of this policy area. Many of these services are provided via partners and selecting partners that could deliver these levels of service without resulting in value destroying penalties might compromise what is possible. We would further note that even the most highly regarded providers such as Citizen's Advice[11] may not be able to achieve these levels of service.

We are therefore concerned that this will create a regime that acts as a deterrent to innovation. We would expect the principle of this incentive is to encourage DNOs to deliver new and enhanced support to both these categories of customers. In assessing any new service, the equal incentive strengths of the NPV and CSAT scores could mean that starting a new initiative where the DNO does not have full confidence that it or its partner can achieve these high levels of CSAT, could result in penalties for the DNO. Ofgem is likely to dissuade DNOs from taking steps with good levels of actual satisfaction and improved outcomes including benefits for customers, if the incentive would penalise the DNO despite the consumer benefit. It is one thing for DNOs to incur costs that might not deliver the anticipated SROI contribution to the NPV, but for new services, without established confidence on CSAT performance, could result in a penalty under the CSAT aspect would likely stifle innovation and reduce consumer benefits in this area given the increase in risk on the DNO.

We propose that CSAT is removed from this incentive (but retained as a reported performance) and focus is given to the social performance indicators. Alternatively, the start of ED2, should be used to act as a baseline score and then improvements set from that point. Further, if the proposal remains to be incentivised, a deadband would be appropriate for this measure and should be actively considered by Ofgem so that the cooling effect on benefits to customers through setting the target too high is at least ameliorated.

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

We agree as this is an important part of our overall strategy we had planned to update stakeholders on our progress in ED2 regardless. Having a common framework will be of increased benefit for stakeholders in allowing them to compare the approaches between DNOs.

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.

In the main the proposed report content will be strong, quantifiable data with clear outcomes to share with stakeholders. How DNOs use the social value framework to inform business decisions and plans will be less structured and could be open to interpretation, therefore we are less clear on the value of this section.

The inclusion of Winter Preparedness in this report will need to be considered in terms of the timing. Should the ODI-R be published around July to align with other regulatory reporting, this will be in advance of the normal cycle of DNOs preparedness planning which normally occurs later in the year. When published in July we will share our initial forward view based on extensive experience of winter preparedness planning considering a review of the previous winter.

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

We disagree and are concerned that there is some misunderstanding by Ofgem of the sustained effort that goes into achieving good performance in both aspects of this incentive.

[11] Citizens Advice – Impact report 2020/21; "*81% of consumers were satisfied with the service they received*"

Paragraph 5.121 of the DD states "*we are mindful that some DNOs would achieve the maximum reward from the outset in some categories with no extra effort*"; this is not our experience where the majority of these connections are with new customers. In reality, each interaction with each customer needs to be; registered, assessed, quoted and then constructed. Typically, as these are new customers, they need to be guided through the process and therefore individual focus and sustained effort is needed to facilitate quick quotes and speedy connections. It is therefore not possible to rest on our laurels as seems to be Ofgem's expectation expressed by 5.121, with even maintaining current levels of performance taking extensive and sustained effort. It is also worth noting that these services sit outside of the price control and therefore the costs of improving the speed of these services will be borne by those connecting customers. We are unclear if Ofgem has conducted any willingness to pay research in considering and calibrating the setting the targets in this area as these connecting customers benefiting from the service will also pay through connection charges.

Additionally, we still have concerns regarding the introduction of penalties to this incentive, particularly in relation to the Time to Connect aspect. In this part of the incentive there are many things that are outside the DNOs control and therefore compromise the principles of a good incentive shared by Ofgem in working group meetings[12]. Further to this:

- Customers will accept (and pay) us before they are ready, so the customer drives the connection taking a longer time through their choice. We try to encourage the customer to make use of our six-month acceptance period but find that only a small proportion do (only around 2 percent accept in last month of validity);
- Some projects need third party consents and the third parties have no incentive to respond quickly which is outside of our control; and
- The majority of the work needs local authority permits to excavate in the public highway.

The latter of these is particularly a concern as the need for Local Authority permits to work in the highway effectively creates a 'standstill' period for the project and acts as a barrier to earlier completion. This means that there is a limit to the performance achievable for most projects in our area as all local authorities operate permit schemes for work in the footpath or highway. These permit schemes are designed to deliver national and local government public policy, so it is surprising Ofgem seems to be making proposals without consideration of other government policy.

We observe that generally this has been an effective incentive in ED1 that has resulted in the performance for most DNOs achieving the targets. Particularly for the Time to Connect TTC) aspects, the performance levels are quite consistent, both annually for each DNO and between DNOs more widely.

It is our view that setting the maximum reward at -50 percent of the average is effectively unachievable, particularly due to the effect of permits, and this risks compromising the power of the incentive. We think a maximum reward of -30 percent of the average for TTC would provide a stretching incentive property where, with the exception of one DNO, there are few instances where DNOs would attain maximum reward based on historical performance.

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

In terms of applying a deadband we agree in principle in this targeted area though we think the approach of an asymmetrical deadband would be more appropriate. For reward, this could start at the target or with a small deadband e.g. 10 percent. However, for penalty, recognising the issues that are

[12] RIIO-ED2 Strategy Delivery Incentive Working Group 10 February 2021: Relevance, Robustness of the process, Appropriateness of the measure, Verifiability and Proportionality.

outside of DNOs control, particularly for Time to Connect as set out in core question 37, then a wider deadband would act as an appropriate buffer if DNO performance declines through issues outside of its control. We consider this approach better represents the actual levels of DNO control on the down and upside around targeted performance.

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

We disagree and note the design of this incentive has changed significantly from SSMD in specific respect of two key regards:

- The assessment approach;
- Incentivisation of non-contestable work; and
- Proportionality of regulatory mechanism including penalty exposure.

We set out our views in these two areas below in turn:

Assessment approach

In the SSMD, the policy intent was to hold DNOs to account for delivery of their own Major Connections Strategy.

"*5.48 We proposed to hold DNOs to account for the delivery of their strategies through an ex post evaluation, in the form of a financial ODI. We set out that where companies do not meet our baseline expectations they could be penalised and that those who outperform could be rewarded. We proposed to undertake the ex post assessment during and at the end of the RIIO-ED2 price control.*"

In order to reduce the regulatory burden, Ofgem sought to develop a mechanistic approach for this and other ODIs. This was done in conjunction with the working group led by Ofgem and a range of potential metrics were identified and assessed against the criteria set out by Ofgem. For all the other ODIs, this resulted in a portfolio of measures that could be combined to assess the relevant area. However, for major connections, the long list of measures was distilled down to a single one based on a customer survey.

The move further away from a more holistic assessment as envisaged at SSMD was compounded at DD where the proposal is to have the assessment based on a 'cliff edge' such that any performance under a specified target results in the full penalty being applied.

We think that the incremental development of this incentive has resulted in an inappropriate incentive that is not fit for purpose and has deviated significantly from the policy intent stated in SSMD.

Incentivisation of non-contestable activities

We understand the core purpose of the Major Connections Incentive is to provide regulatory protection for customers where there have not been demonstrable levels of competition.

At SSMD, the policy position was clear that the incentive would only apply to market segments that had not demonstrated that there was competition; the treatment of non-contestable activities was explicit and would be reputational only.

"5.73 ….We note that the financial incentive will not apply for non-contestable works in market segments that have passed the Competition Test. We consider that existing licence arrangements ensure that DNOs deliver specified standards of performance for these customers. However, to ensure

that DNOs deliver best practice in the provision of non-contestable activities, our assessment of DNOs' performance with regards to these activities will apply on a reputational basis only."

In October 2021, the treatment of non-contestable services introduced the potential for incentive rewards. *"For non-contestable services, we will continue to explore the potential application of upside financial incentives or rewards."*

However, in DD, this changed to include non-contestable services in the ODI metric and therefore effectively they now form part of the proposed penalty only mechanism.

The table 8 below summaries the changes in policy position for each category of Major Connections activity.

Table 8: Changes in policy position for each category of Major Connections activity

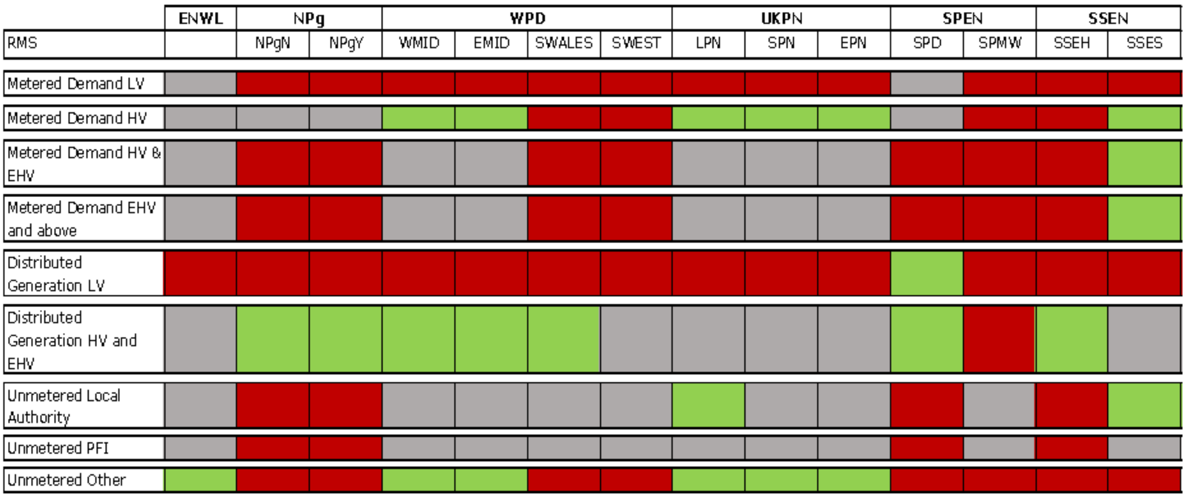
<table>
<tr><th></th><th>Passed – contestable</th><th>Passed- non-contestable</th><th>Not passed, but prospect of competition</th><th>Not passed, no prospect of competition</th></tr>
<tr><td>SSMD (Dec 2020)</td><td>No financial incentive</td><td>Reputational only</td><td colspan="2">0.1% base revenue for each RMS not passed

Reward dependent on level of competition</td></tr>
<tr><td>Decision on Competition Review (Oct 2021)</td><td>No financial incentive</td><td>Explore potential for reward</td><td>Penalty only for contestable.

Explore potential for reward non-contestable</td><td>Financial incentives on reward-and-penalty basis</td></tr>
<tr><td>Draft Determinations (June 2022)</td><td>No financial incentive</td><td>Financial incentive, penalty only</td><td>Financial incentive, penalty only</td><td>Financial incentive, penalty only</td></tr>
</table>

Seven out of 14 licence areas now have three or less market segments where competition has not been established as set out in the table below. As the proposed ODI mechanism is to survey customers in market segments not passed plus all non-contestable services, we believe that non-contestable activities will have a major bearing on the outcome of the survey and therefore will result in penalties based on third party activity. This would mean that our competitors would have an undue influence on DNOs and we do not see how this is compatible with the intent state in 5.140 *"Where competition exists, we do not want any incentive(s) to distort it."*

Figure 6: Ofgem competition assessment consultation position



We would propose two options both involving separate surveys for RMS where competition was not demonstrated and for non-contestable work in RMS where competition was demonstrated. In both options, any RMS where competition was not demonstrated would be a penalty only incentive (consistent with SSMD) with customers in any of these RMS being surveyed and the aggregate level of satisfaction used to compare against a target to determine the level of penalty, if any. For the treatment of non-contestable services where competition was demonstrated then our proposed options are:

1. Reputational only for non-contestable work.

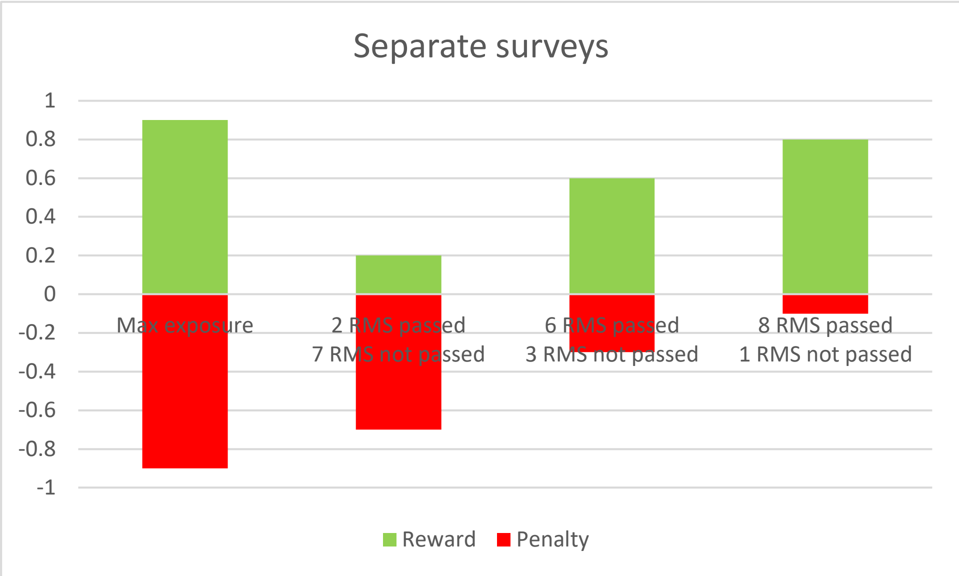
Non-contestable services in market segments that *did* demonstrate competition could be surveyed separately and the results published. This would result in a reputational incentive, consistent with SSMD, and avoid any risk of distortion in these competitive markets. For absolute clarity these should be removed from any assessment of financial incentive to avoid distortion of or from competitive market segments.

2. Reward only for non-contestable work.

There are currently multiple obligations placed on DNOs to support competition in Connections. Standard Licence Condition 15 sets standards of performance when DNOs provide services to third parties though virtually all of the work needed to be done to make a connection is open to third parties through the introduction of the Competition in Connections Code of Practice in 2016. Standard Licence Condition 52 introduced specific obligations to comply with this code of practice and support competition.

If Ofgem wants to create a strong incentive for these services, then this could be enhanced by applying a reward only incentive to this aspect. This could be applied symmetrically with the maximum reward and penalty being equal. A similar principle to using the number of RMS where effective competition has not been demonstrated to calculate the level of penalty could be used. To calculate the level of reward, then the number of RMS where effective competition was demonstrated could be used to scale the level of reward. This is illustrated in figure 7 below for three scenarios. This approach further supports those DNOs that have supported Ofgem policy to support competition as it increases the opportunity for reward and reduces the level of penalty risk based on the DNOs success in supporting competition.

Figure 7: Example RMS scenarios



In this approach, as the incentive is reward only then the risk of distortion is removed, ICPs and IDNOs will be the recipients of the service and will get the benefit of improvements in service. If they are not satisfied, they will provide low scores and the opportunity to earn reward will be lost by the DNO with the reputational incentive properties remaining.

Proportionality of regulatory mechanism including penalty exposure.

On 24 August Ofgem published the, "*Decision on the review of competition in the electricity distribution connections market*". The outcome for ENWL was that only one Relevant Market Segment (RMS) has not been passed. However, the RMS assessed as not competitive is the DG LV segment that is incredibly small with an annual turnover of less than [redacted]. The RMS penalty methodology proposed under the ODI-F for connections though leaves us with a level of annual penalty risk of [redacted] our total turnover. We consider this a material error to set the range of penalty without reference to the size of the segment and therefore the consumer impact. The proposed penalty is disproportionate and illogical. We had proposed to Ofgem in coming to its decision on the review of competition in ED connections market that an in the round assessment needs to be made. We understand that Ofgem considers that the scope of that decision could not include an in the round review. However, since Ofgem is consulting at DD on the ED2 incentive framework we suggest that Ofgem:

a) Does not subject our low materiality [redacted] turnover p.a. RMS in the incentive as Ofgem should apply a "turnover test" to each RMS (i.e. set the turnover test at greater than the value of the penalty). Where the proportionality test fails, such that a RMS has a turnover of less than [redacted] p.a. the market segment should switch from being ODI-F to ODI-R.

b) Ofgem could redistribute the totality of the maximum penalty based on the average turnover proportion on the last three years RRP data;

c) Ofgem should apply an 'in the round' assessment to which RMS are subject to the ODI-F and may decide not to apply the ODI-F on this basis to certain or several segments. In this case the segment would not switch to ODI-R and, for ourselves, this would mean the proposed ED2 Major Connections incentive itself would effectively be turned off.

The solutions we put forward here are not mutually exclusive and could be combined in different ways.

Overall, we do not consider it proportionate for Ofgem nor for consumers and stakeholders to apply a complex regulatory tool of the ODI-F for connections during ED2 to what amounts to a business activity of [redacted] turnover p.a. magnitude.

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

We fundamentally disagree with the proposed approach.

The proposed approach to target setting is inconsistent with other approaches. The proposed approach takes targets that were set as aspirational targets in DNO Major Connections Strategies and uses these to set an arbitrary threshold at which to apply penalties. There is no consistent performance data and therefore we would suggest a more appropriate approach is to baseline performance in year one and then use that to incentivise improvement.

The rationale from Ofgem for applying a binary, all or nothing approach to this incentive is flawed. Whilst this approach is applied currently in ICE, it is applied after a holistic assessment and one where DNOs have the ability to provide responses to any issues raised to Ofgem. By contrast this is intended to be a mechanistic approach and therefore will result in undue weight being placed on, potentially a single, survey response that tips the score over the target. We think a graduated penalty that starts at an appropriate threshold would be more appropriate and consistent with other satisfaction surveys. As the results of surveys are difficult to anticipate, the deterrent effect of a penalty will drive the focus on service improvements. The threshold for penalty does not need to be set at such a high level, particularly where there is no historic data to set it on.

As explained above, we are concerned that some market segments are quite small and therefore the number of respondents may be quite low. In order to maintain the integrity of the incentive we believe that minimum sample sizes should be set such that the mechanism works on a reputational only basis if sufficient numbers and statistically meaningful numbers of respondents are not achieved. We suggest the threshold is set at there must be more than 30[13] meaningful survey responses.

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

We disagree and are unclear on the Ofgem rationale for applying this extra reporting burden on all market segments. This simply imposes an extra regulatory burden on DNOs and risks distorting competition as DNOs already have extensive reporting obligations. For market segments where there is not competition, then we would agree that reporting on these measures has merit and is of benefit.

We would urge caution in requiring reporting on Time to Connect. In our experience the timescales are more often dictated by the customers' requirements rather than by choice or necessity by the DNO. Creating a new reporting requirement would create a reputational incentive and may lead to unintended consequences where DNOs are encouraged to terminate connections and this would in most circumstances be counter to those customers desires.

[13] Based on central limit theorem (CLT) widely referenced in statistics. CLT states that the distribution of sample means approximates a normal distribution as the sample size gets larger, regardless of the population's distribution. Sample sizes equal to or greater than 30 are often considered sufficient for the CLT to hold.

Incentivising Time to Connect was considered when GSoP standards were developed, but stakeholders supported the approach that an agreed date for each project should be set and success measured by reference to that date, appropriate to that project. We think this remains a better indicator of DNO performance rather than the proposed approach as this approach measuring against the agreed target date places the customers wants and needs being met at the heart of the incentive.

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)?

The rationale and scope of the review is unclear and therefore it is difficult to support what could be an extensive exercise. We would be happy to work with Ofgem to better define the desired outcome before this review is formally initiated and would actively encourage that this scoping stage happens. As additional context we would refer Ofgem to some metrics we proposed[14] to measure timescales for LCT applications as this might form the basis of new reporting, but without trying to develop Guaranteed Standards at this stage. Collecting more information is vital before jumping straight to committing to designing and implementing new guaranteed standards.

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 (i.e., end to end) time to connect?

The biggest challenge to speedy connections our customers currently endure is due to transmission constraints and lack of timely transmission capacity. This is largely outside our control. We understand from our involvement with other industry stakeholders that the issues with problems connecting to distribution networks because transmission networks are effectively closed to new connections and capacity takes years, even decades to build out is an urgent national issue to solve.

One of the solutions might be more effective queue management on the transmission system. We observe GSPs on our network that are effectively closed for new connections due to transmission issues, despite us having capacity on our distribution network. The GSP has a queue, but in practice we can see actual headroom not being used as capacity is being held to meet contracted connection offers to the transmission system. This situation needs urgent overhaul.

5 Maintain a safe and resilient network

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?

Yes, our engagement for our business plan led to an in-depth understanding of consumers' willingness to face small increases in bills to deliver reliability and found strong evidence-based support for this both quantified (via WTP) and qualitative via informed panel discussions.

A key learning from our engagement programme has been the value of triangulating set-pieces of quantitative research such as willingness-to-pay (WTP), with deeper, longitudinal and deliberative engagement with consumers. The latter enables more informed and richer perspectives. Our Public Panel, a representative sample of 40 North West consumers, spent over 100 hours deliberating and challenging our leadership team on different areas of our plan to which they attributed value.

[14] See section 4.3.1 Customer experience metrics in Annex 3A Load Related Expenditure

One such area was improvements in their power supply reliability where throughout our engagement we included information about the funding for our propositions for reliability clearly[15] in that this was incentive performance based rather than baseline meaning customers would only pay additional costs for benefits/improvements in service realised. This key context was included in our early draft, draft and final plans in April, July and December 21[16].

To sufficiently contextualise the conversation, we provided the panel with the costs associated with fault prevention, as distinct from fault restoration, and how this expenditure compared to other categories of network investment during 2015-2020. We provided the panel with our RIIO-ED1 reliability performance trended over time and at a granular level – so that they could appreciate regional differences and reflect on the benefit delivered from expenditure to date and the need for further improvement. We explained how our performance is translated into an average – using the industry standard of CMLs and CIs.

The panel asked for more information on the volume of customers impacted and the likely costs of improvement. In a subsequent session we set out potential improvements to existing service levels (the ones tested in willingness-to-pay) and openly shared constraints that would make improvements beyond these highly ambition levels unlikely in ED2. In response to their feedback we also normalised the cost of delivering this improvement to the impact that it would have on their annual bill – relative to the other potential improvements we could make in other areas (in £ and pence).

WTP monetary values were assessed at the 80th percentile, in line with the minimum standard we set ourselves for acceptance of our Business Plan. This provided strong evidence that >80 percent of customers would be willing to face an increase in their bills to also receive an increase in their reliability. This is purely a measure of consumer value and not the cost of delivering the service. Therefore, we triangulated WTP insight regrading consumers expectations/priorities with other measurement approaches e.g. our deliberative panel feedback and SROI to create the best value proposition.

It is this triangulated evidence base that enabled us to iteratively develop our reliability proposals with customers and stakeholders so that 86 percent supported the final investment proposal.

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?

Setting the cap too low for DNOs restricts their delivery of further available network performance improvements and thereby disadvantages some customers. Quite the opposite from lowering the cap, we propose that Ofgem consider removing the cap completely, allowing network operators to continue to invest until they reach the economic break-even point beyond which the forecast benefits of further improvements (i.e., those that manifest from the IIS mechanism) are outweighed by the cost of making the improvement. Unlike the IIS revenue collar, which limits in part the overall risk liability DNOs face when undertaking licensed obligations, the cap only acts to restrict improvements in

[15] "Reducing number of power cuts and time without power: No upfront allowances – payment on results only via Ofgem's IIS incentive mechanism"

[16] Early draft plan: page 56: https://www.enwl.co.uk/globalassets/stakeholder-engagement/engagement-hub/early-draft-bp-for-consultation-v1.0-v4.8.pdf

Draft plan: page 74: https://www.enwl.co.uk/globalassets/about-us/regulatory-information/riio2/july-2021-submission/draft-plan/draft-business-plan-2023-2028.pdf

Final plan: page 62: https://www.enwl.co.uk/globalassets/about-us/regulatory-information/riio2/december-final-submission/our-plan-to-lead-the-north-west-to-net-zero-2023-28.pdf network performance. On this basis, rather than the cap being lowered as is proposed, it ought to be removed completely.

The proposal to lower the revenue cap, combined with the associated weakening of the IIS incentive rates compared with that of previous price control periods (through the retention of the average demand function in their calculation), will be particularly challenging for DNOs, coming at a point in the reliability improvement journey where network performance gains obtained from incremental investment are reducing. If DNOs are to continue to be adequately incentivised to invest to improve network performance, rather than just maintain current performance, the diminishing nature of incremental returns call for stronger incentives rather than weaker ones as is proposed for ED2. During our planning for quality of supply investment during ED1, it was common for planners to reject proposals owing to an inability to obtain a positive net present value when the cost and benefits of the proposal were assessed against the RIIO-ED1 IIS regulatory incentive regime.

As the costs of the investments are likely to remain unchanged in ED2 – in many cases they will increase owing to external cost pressures in the supply chain – the weakening of the value of the associated benefits will result in more network performance proposals failing to pass the economic tests. While DNOs could mitigate some of the effect, by for example, combining similar investments into packages to form multi-vector solutions, the outcome of the reduced rewards in ED2 will be less overall investment in network performance improvement versus previous price control periods.

When any network operator’s level of performance is expected to result in their breaching the proposed lower IIS revenue cap, they will likely respond by halting any further investment and thereby stop delivering further improvements for customers. It is evident that DNOs whose discretional investments are economically rational, will cease to invest if the assessment of benefits is lower than expected costs. However, in failing to adjust the incentive rate for CI and CML as was proposed by DNOs during ED2 price control discussions, Ofgem’s proposals for IIS in ED2 result in a weakening of the IIS mechanism and a consequence the appetite of network operators to invest shareholder returns to further improve network performance. Using a simple but very common investment scenario we can show how Ofgem’s proposal to weaken the incentive on network operators will result in their making less investment and mean there are missed opportunities for customers.

Table 9: Example Investment scenario

<table>
<tr><th colspan="2">Proposal: to install a second remote-controllable (RC) actuator to a HV connected distribution ring main unit (RMU) supplying 300 customers, and the commissioning of this new remote-control switch into an existing network automation scheme.</th></tr>
<tr><th>Costs</th><th>Benefits</th></tr>
<tr><td>Owing to previous quality of supply investment made by the network operator, the RMU is already equipped with RC. However, owing to funding limits at that time, only one of the two HV switches on the RMU was fitted with RC, the other switch remaining non-automated, requiring manual operation. All associated communications and auxiliary equipment had been fitted, enabling the future upgrade of the RMU to have both switches made RC.

Owing to there being further opportunity to invest in Quality of Supply, perhaps as a result of efficiencies made elsewhere in the network operator company or because of cost savings of associated equipment flowing from procurement initiatives, the network operator now wishes to upgrade its RMU by fitting RC on the second HV switch.

The cost of the actuator is roughly [redacted] and, depending on installation methods chosen by the network operator, it could cost in the region of [redacted] to install and commission the new RC switch.

In this example, the total investment is around [redacted].</td><td>Deriving the benefits that might reasonably manifest from the upgrade of the RMU to have both its HV switches fitted with RC is a complex assessment.

First the network operator must consider the chances that there will be a future fault on the associated HV networks following which the second RC switch will likely deliver a performance improvement. This requires reliability studies be performed which determine the associated CI and CML that might be obtained each year should the second switch have RC fitted based on the probability of failure of associated networks and the numbers of customers that might be affected by any future fault.

Owing to the way Ofgem ratchets IIS targets and adjusts aspects such as IIS incentives each price control, an economically rational network operator will only assume benefits from these forecast annual CI and CML savings until the end of the price control period. Any benefits beyond this must be reduced, taking into account the inherent regulatory risks.

As with all work on the electricity distribution network, there are considerable delivery risks. These are mitigated by effective planning and use of approved procedures. However, before any work is done on the network, an assessment of all attendant risks would be necessary. Where that work is discretionary in nature such as with Quality of Supply, the benefits of carrying out the work must be greater than the overall costs including risks.</td></tr>
<tr><td colspan="2">It can be seen from the above that while the benefits of the proposal are likely to reduce owing to Ofgem's proposals for IIS in ED2 which weaken the incentives in this area, the costs of the investment will if anything increase owing to inflationary pressures on supply chain. In addition, several other factors are acting against us:

The benefits from incremental investments such as that shown above are subject to the economic law of diminishing returns. In previous years, network operators will have identified sites with higher customer numbers and fitted the RC there first. They are now having to target sites with lower customer numbers and therefore lower expected overall CI and CML benefits.

The regulatory period and therefore the number of years during which the CI and CML benefits can be assumed by the network operator is reducing from 8 to 5. This will lower the total expected benefits from the proposed investment.

Inflationary pressures are pushing up the cost of the RC equipment meaning what was [redacted] in 2020 could cost [redacted] in 2023. At the same time, Ofgem is proposing to reduce the incentive rates.</td></tr>
</table>

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

Ofgem indicates it is concerned that companies have secured rewards for what Ofgem considers to be simple to achieve performance improvement. This has not been the case, as delivering improved and ever greater network reliability has required new approaches, innovative actions and unfunded costs of investment and operations to deliver the performance improvement. Unfunded costs have been incurred to achieve the performance improvement, and risks taken in delivering changes, which offset and eat into the level of IIS rewards achieved which are themselves the funding mechanism for the improvements.

The IIS revenue collar limits in part the overall risk liability DNOs face when undertaking licensed obligations. On this basis, licensees will consider their exposure in the round alongside the many other attendant risks associated with the price control. Quite apart from the collar, the revenue cap only acts to restrict improvements in network performance, meaning that some customers are prevented from benefiting from investments that might otherwise be made by network operators. This is unfair on these customers. On this basis, rather than be lowered as is proposed, the cap ought to be removed completely.

We do not agree with the asymmetry proposed by Ofgem as it artificially restricts improvements that customers have indicated that they want and are willing to pay for and exposes the DNO to risk from the asymmetric incentive design that is it not rewarded for managing. We have set out our views in response to Ofgem's specific reasoning in table 10 below.

Table 10: Response to Ofgem reasoning

Ofgem Reason (Para 6.33 of core)	Response
we [Ofgem] consider that the cost to consumers from small deteriorations in reliability performance could be disproportionately higher than the benefit from an equivalent level of improvement.	Ofgem states in various places that evidence is key in its decision making so we call on Ofgem to publish its own evidence on this assertion. Ofgem has not presented any evidence to justify asymmetric consumer preferences, which represents a key departure and a very material change.
we [Ofgem] want to maintain a strong incentive for DNOs to avoid their reliability performance deteriorating where they reach the cap, even if they no longer have an incentive to continue improving it.	It is clear with a symmetrical design around 100 RORE bps that DNOs will have an incentive to avoid penalties against the targets. These penalties at 100 RORE bps are very material. Adding extra downside risk onto DNOs beyond the symmetrical design needs to be compensated within other elements of the price control. Ofgem should set out how it's price control directly addresses a DNO being enabled to address the proposed excessive downside risk (extra Totex allowances for example).

Ofgem Reason (Para 6.33 of core)	Response
based on the DNOs' performance since the IIS was introduced, we [Ofgem] think the risk that a DNO will underperform to the extent that they are at risk of reaching the cap is very low	Ofgem makes various references to its views on how the marginal costs of addressing reliability are an increasing curve, as well as Ofgem citing many DNO areas have world class performance. We agree with both these observations though to us these point to the increasing difficulties and inherent challenge in avoiding IIS penalties. Even if Ofgem believes the risks are lower based on history there seems to be no account for past not being a guide to the future performance. Even tighter targets are proposed to be set for ED2 which has made both the challenge of improvements and avoiding deterioration harder in ED2 than ED1. Notwithstanding these points Ofgem has not consulted upon nor shared its evidence with stakeholders.
changes we [Ofgem] are proposing to make to the CML target setting methodology will further mitigate the risk of DNOs falling into penalty over the five-year price control period.	This, aligned with the previous Ofgem point of justification that amounts to Ofgem asserting a view of the penalty not biting in practice, all points towards placing a risk on DNOs without real benefit as Ofgem seems to imply the downside range in the view of Ofgem won't be reached. Ofgem's view that the collar won't be reached is less important than the subject companies view which is that the asymmetry imposes a substantial and real downside risk on the company, without funding nor reward for taking this risk on elsewhere within the framework. This is because companies own view will drive their own actions.

Incentives are a key part of the RIIO framework.

Further, when considering the costs of improvements, Ofgem needs to look far beyond any capital costs reported as 'QoS'. Restoration improvements in particular come with sustained increases in a range of other operational costs such as levels of staff across our business e.g. control room, contact centre and field operatives, supporting IT systems and processes, type and numbers of vehicles and hence world class levels of reliability performance incur costs in many areas. Because of the complex interrelationships between costs and ways to improve IIS performance, the ways and costs to achieve this performance have been left to DNOs to assess and take the risk as to whether particular measures will deliver incentivised benefits greater or less than their overall cost to achieve.

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 agree that hitting the revenue cap is bad for customers, but not in the ways Ofgem state. We believe it is bad for customers because it removes the incentive on DNOs to continue to invest to improve network performance. This means that while there might be an appetite for further investments and opportunities have or can be identified, the artificial cap on allowed revenue means that an economically rational network operator is prevented from investing. Those customers that otherwise would have benefited from the performance improvements resulting from the investment will continue to experience the negative consequence of future network faults. This can't be right. Instead, Ofgem ought to remove the cap completely, allowing network operators to continue to invest until they reach the economic breakeven point beyond which the forecast benefits of further improvements (i.e., those that manifest from the IIS mechanism) are outweighed by the cost of making the improvement.

Ofgem is mistaken to make the strong link it seems to that hitting an IIS revenue cap is actually bad for consumers. It is extremely positive, meaning great strides have been made to improve reliability and due to how the IIS payments were set, the reward never exceeds the value of the benefits to consumers. So, consumers benefit from IIS at every marginal improvement delivered whilst the company take the risk on needing to effectively deliver the improvements at lowest cost. We therefore challenge if a balance needs to be struck in the way Ofgem hypothesises and if this is even possible without a dis-benefit to consumers compared to a more open upside that causes companies to strive for improvements.

In summary, our design of the IIS incentive would have a smaller collar. If Ofgem maintains such a large downside collar, the implications of this need to be addressed by other changes to the price control to reward and fund management of the excessive downside risk.

A cap on the incentive does not seem to be in consumers interests as it's a cap on ambition to reduce power interruptions. What is key, and is the case for IIS, is that where any incentive payments are made these are the same as or lower in value than the value of the benefits consumers enjoy.

Overall though a much less excessive collar (more in line with the quantum of the DD's proposed cap) value is the key change that Ofgem should make in the FD.

Some additional thought should also be given to RAMs. Ofgem stated the purpose of the RAMs mechanism is to control overall returns, though as referred to in our response to question 27 of our Finance annex response, the policy goal of Ofgem is not achieved as it merely applies the RAM to a fictional, notional company, not therefore providing the controls and influences on the actual company Ofgem says it is seeking to achieve. So, the policy objectives of RAMs are never reached as no actual company is subject to the policy forces as Ofgem intends. Nevertheless, the interaction between the proposed RAM and the IIS asymmetric mechanism is not properly assessed by Ofgem in making the proposal for asymmetry. Since the RAM is proposed to operate at +/- 300 bps, the downside IIS asymmetric collar could be a major interacting factor with the RAM in certain circumstances and merits exploring, particularly where the notional company might be materially overfunded or underfunded its financing and tax costs.

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 with the change of CML methodology to align with the approach for CI. We note the reasons for change and support both the reasons why and the proposal as laid out in the DD which give greater consistency across the target-setting process. We also agree with the targets proposed for CI and CML as set out in our response to Q1 ENWL company specific response.

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?

If the IIS mechanism is effective, including with sufficient reward incentives, encouraging DNOs to invest shareholder's money in improving the performance of the network, we agree that the funding of explicit QoS improvements through allowances risks customers paying for the same improvements twice.

However, we are concerned that the Ofgem proposals for ED2 which include for a lower IIS revenue cap and a lower CI and CML incentive rate, would effectively neuter the IIS mechanism, resulting in no further improvement in network performance. In effect, network operators would maintain performance at or around ED1 levels. Given customers' greater reliance on reliable electricity supplies as a means of heating their homes and powering their cars, it can't be right that owing to changes made by Ofgem in the IIS mechanism and the resulting lack of a strong business case for investment, network operators make no further improvement in network performance. Network performance data shows that many customers continue to experience interruptions to their supply owing to faults and the experience is not the same for all customers.

If the incentive is there, network operators have the appetite to invest, and the solutions are available. It's important that Ofgem does not undermine this demonstrably successful incentive mechanism.

We note also that Ofgem has rejected our proposal to improve reliability for vulnerable customers. This has only a very marginal impact on overall QoS performance but a significant benefit to those vulnerable customers who benefit, as set out in our accompanying EJP.

We are concerned that this initiative has been mis-understood as 'QoS' due to us having to use this category for the initiative within the constraints of the BPDT classifications.

We have engaged with the Ofgem team on this issue and provided additional information on the context and benefits of this programme in our response to Q3 of the ENWL Annex. We look forward to continuing to discuss our proposals in this area with Ofgem ahead of the FD.

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 agree with the sentiment of Ofgem that claims via the Other Exceptional Event (OEE) component of IIS should be genuinely exceptional. We consider however that there is a risk that Ofgem moves too far in trying to tighten up the definition, inadvertently removing the ability for DNOs to put forward legitimate claims for exceptional incidents affecting its network.

One example of a fault related interruption which is genuinely exceptional is a previous incident that occurred on our network involving a double circuit cable strike by a third party. This created a significant duration and customer impact. All DNOs have this historical vulnerability (cables laid next to each other in the ground). It would not be cost efficient to remove the risk in totality given that the likelihood is extremely remote.

Another example is the catastrophic damage we experienced at our Grid site in Lancaster as a result of storm Desmond and associated flooding in 2015/2016. Whilst this was a severe weather event, the resulting work to bring the site back to resilience, with flood defence works, resulted in the system running abnormally with two grid transformers instead of three. In June 2017 whilst these works were underway we experienced a cable fault on one of the cables to one of the remaining grid transformers. This resulted in a significant number of customers fed from this grid site being affected.

Other examples include localised lightning events or catastrophic flooding which do not meet the volume threshold for SWEE events but result in significant impact and damage.

We are keen to work with Ofgem to reach a position where the definition of an exceptional event can be achieved, whilst removing the risk of unintended consequences and providing DNOs with an untenable level of risk exposure and consider this can be achieved amongst DNOs and Ofgem between now and FD.

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

We agree with the analysis quoted by Ofgem that supports the retention of common OEE thresholds as this results in similar financial exposure for all DNOs.

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 agree with the proposal as laid out in the DD. A UIOLI mechanism with associated reporting provides sufficient transparency and accountability to ensure that DNOs deliver for their customers in line with expectations.

We note that Ofgem intend to provide guidance on how the UIOLI should be applied in the context of the licence obligation. It is critical that any guidance which DNOs are obliged to comply with in ED2 is available for DNOs to view well ahead of FD and that this guidance is not developed by Ofgem in isolation. This should be able to be viewed in line with, and alongside, any redrafting of associated licence conditions.

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

We note the work that Ofgem is progressing through the Safety, Resilience & Reliability Working Group in the development of a Worst Served Customers Allowance Governance document and we will contribute to the development of reporting metrics through that forum. It will be important to ensure alignment between this document and the associated licence condition drafting, and that it sets out the key reporting metrics with sufficient clarity.

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

We are pleased to note that Ofgem has accepted our proposed risk points target and maintained the target as a single figure in line with the SSMD.

The risk points output in our FBP submission is a function of a specific set of volumes delivering specific outcomes and we are concerned that Ofgem has broken the link between volume assessments and risk point achievement in the DD.

It is essential in the FD to ensure that the baseline allowances are consistent with the associated risk points targets as these will set the basis for NARMs delivery and close out within RIIO-ED2. We have discussed the importance of this consistency with the Ofgem teams and are following up on specific issues in this area with the Engineering Hub subsequent to the submission of this response.

Should a major inconsistency remain at FD between the proposed risk point achievement and the associated allowances derived through the Cost Assessment process, we will consider our original proposals null and void in this area and propose a re-submission consistent with the levels of allowed funding.

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?

Yes, we do, as this covers the unpredictability of 1-in-20 events both in terms of incidence and scale. We will continue to work with Ofgem in developing a clear set of guidelines in terms of eligible expenditure under this mechanism, reflecting on our experiences of storm Arwen, and ensure that these are captured appropriately in the RIGs.

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?

Yes, we do, as it is not feasible to identify in advance the likely costs of low probability high impact events in a five-year period.

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

We agree with the proposed approach as laid out in the DD.

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

We welcome the inclusion of a re-opener covering the uncertain impact of Black Start/ ESR activities. This re-opener is vital to ensure that DNOs can engage and deliver on any requirements established based on the obligations that are placed on us as companies and a sector.

Further, as this is an NGESO workstream but with potentially significant impacts on the DNOs it is clear that the timings, scope and cost of implementing to ensure compliance is outside of the DNOs' control entirely and are all at the behest of NGESO. It is in this context that we offer the following positions on key aspects of the proposals for the re-opener as set out in the DD:

- **Scope:** We support that the scope proposal covers "*costs relating to new obligations for ESRS*". For the avoidance of doubt our interpretation of this is it includes both direct and indirect cost impacts including legal/commercial contracting costs as well as the costs of assessing, evidencing and producing our re-opener submission in relation to ESR and this re-opener. It is on this basis we would support the scope.

- **Trigger and Re-opener window:** Our position and proposals are that a single/fixed re-opener window is insufficient given the differences in timing and rollout across the country, the uncertainty of ESO activity and delivery dates, and the potential for programme changes/variations regarding the same.

  Given this, we recommend that an open window is maintained whereby the DNO can trigger the re-opener window at such point where the need is understood, and the costs known whereby sufficient time to develop the application is given (for example 12 months). This should occur ahead of when obligations 'go-live' to ensure that DNOs are not left with unfunded obligations which are wholly outside DNO management control causing cashflow issues/ risks.

- **Materiality Threshold:** We strongly support the position of a zero-materiality threshold in this area given its importance, compliance-based nature and by the fact that this is wholly outside of DNO management control.

We remain of the view, expressed previously, that Ofgem needs to keep considering if these works for national security of supply and resilience benefits should be regionally funded by DUoS customers. If the measures are for national benefit and national need, then these should be funded via the ESO's price control with the ESO funding DNOs and funding being recovered nationally from BSUoS.

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

We agree with the principle that PSTN activities as understood at the time of submission are funded within baseline allowances, however we draw attention to the fact that Ofgem has not included any consideration of this in their disaggregated cost assessment for Telecoms costs which is completed on a macro, 13-year MEAV basis, together with the entirety of the IT costs.

Our FBP considered that the potential changes to strategy arising from the possible future allocation of radio spectrum are unlikely to result in changes to Telecoms resilience in ED2 and therefore made no provision for this work in our FBP. The actions arising from the storm Arwen investigations which occurred after our business plan development and submission may however accelerate this work to assign spectrum.

We therefore propose that the storm Arwen re-opener be scoped to include this issue and relevant impacts of the storm Arwen investigation on Telecoms resilience in ED2. We provide our full response to the Arwen re-opener proposals in Q3 of our response to the Overview document.

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?

We agree with the principle of re-openers for cyber resilience IT and OT plans, however have concerns with the first window being at the start of year 1 as laid out in our response to Q61 below. Just as we have been finalising this response we received an invitation to a meeting with Ofgem on cyber resilience regulatory treatment which we then sought to clarify the intent of. At this stage Ofgem's position is therefore unclear to us so our response is based on the published DD.

Sufficient baseline allowances over a long enough period of ED2, plus re-openers are critical in this area given emergent threats might require DNOs to react to request funding at short notice; therefore, an agile approach by both Ofgem and DNOs is necessary.

We have responded to the separate cyber resilience questions and also a consultation on PCD reporting as part of this response process.

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

We are extremely concerned that the proposed approach of providing only one year of allowances makes year one look like a year focusing only on planning, rather than delivering benefits and reducing risk from day one. The Ofgem approach is an old-fashioned waterfall approach, whereas especially for cyber security, an agile DevSecOps approach is much more appropriate.

Additionally, some of the capital projects starting in year one will span multiple years, making contracting with suppliers difficult and increasing the level of risk the company carries due to uncertainty over the funding position for such projects.

Recruitment in the current market is challenging for specialist cyber resources. Allowances for only one year pushes us down the fixed term contract route making recruitment harder. Alternatively, we could utilise contractor resource which will in turn increase costs for our customers.

For these reasons we fundamentally disagree with the proposal to apply only one-year funding to this critical business area. Ofgem should reconsider this approach and the unintended impact it will have on the ability of DNOs to adequately manage this area of activity. We look forward to working with Ofgem between now and FD to resolve this key gap and will seek to understand what further information Ofgem requires in addition to that already presented as part of our plans in order to progress this issue.

With regard to the proposed re-opener windows, we strongly urge Ofgem to take a more pragmatic approach to the first re-opener window, as there are practical challenges in delivering the level of detail Ofgem wants. We suggest this moves to January 2024 to enable a robust re-opener application to be brought forward (as well as we propose having sufficient funding in place from the start of ED2). The second window should therefore also move by the same nine-month change, and instead of April 2025, be January 2026.

We strongly support that the cyber re-opener application proposal format and process is consistent with other areas, not as onerous as currently proposed. As we have mentioned in our earlier responses to question 21, this of importance if TBM is introduced for DSAP or in any other areas.

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

We disagree with the proposed treatment for Cyber OT.

Applying both a PCD as well as UIOLI overcomplicates the area and risks making it more difficult for DNOs to deliver, especially combined with the Ofgem approach in DD to set only one-year allowances with a re-opener. The use of two regulatory mechanisms for one activity creates unnecessary complexity and regulatory burden for no consumer benefit.

Both a PCD and a UIOLI are different ways to set parameters on a DNOs expenditure and despite us asking a supplementary question in this area, we are still unclear as to how they can work together for one area of activity.

Our understanding of a PCD is that it is designed to set controls on how allowances are spent, to hold companies account for delivery of either outputs or outcomes, with an Ofgem assessment at the end of period against these parameters. If a company delivers, then there is no action, if it does not, there is a clawback.

A UIOLI also has controls on how allowances are used with a clawback applied on any unused elements. Outside of a defined outcome or output, these two mechanisms are fairly similar, and we do not see any rationale for both being used in this area.

We agree that cyber resilience requires a certain level of flexibility in how the outcome is to be delivered as may be required by advances in technology, or changes to the threat level and therefore consider that a UIOLI allowance is the most appropriate regulatory treatment in this area, but importantly Ofgem needs to be agile and provide timely UIOLI allowances as needs change, if as we might anticipate more delivery activities are required to provide cyber resilience, as new threats emerge or existing threats change shape.

Whilst we agree that the activity of cyber resilience is important, we have not seen sufficient justification as to why this specific area of DNO activity has such a different regulatory treatment to any other critical resilience expenditure. We do not consider that because it has been set that way for Gas Distribution to be sufficient justification for the same application to ED.

We consider that UIOLI and a PCD perform similar functions and that either would be appropriate for ED2, but a combination of both is unnecessary and provides no further consumer benefit. We consider that the most appropriate regulatory treatment is via a UIOLI mechanism. This would ensure that companies have the necessary funding to deliver against its cyber plans, whilst maintaining flexibility to adjust the means of delivery as necessary whilst protecting customers against the risk of under-spend.

Further, we note that the reputational incentive in this area of activity should not be under-estimated and is sufficiently strong to ensure that companies deliver on their plans and protect customers from arising risks.

We believe Ofgem proposes a different regulatory treatment for OT and IT cyber resilience. We have not noted the reasoning for this and consider it a surprising conclusion to have different regulatory approaches for the same driver.

6 Delivering at lowest cost to energy consumers

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

We strongly disagree, and we consider that our submission has been fundamentally mis-represented by Ofgem in the DD. Ofgem has moved four cost items from our M13 table into the Totex baseline, one of which (unlooping) was changed in our base data so does not even show as an adjustment in Ofgem's modelling.

We agree that PCBs require separate treatment under an uncertainty mechanism, hence our including them on table M13 in the first place. We note that these get added to baselines and then removed into a proposed UM which we look forward to working with Ofgem on developing the detail of. We agree that the testing and GM transformer elements of this programme are smaller scale and more predictable hence could potentially be added to the Totex baselines. In Ofgem's assessment of this area however, our costs moved from table M13 do not have associated volumes and therefore get benchmarked to zero – this needs correcting for the FD.

For the other three movements, we included upper range scenarios on table M13 to state the case for UMs in each regard. We note that Ofgem have accepted the case for an unlooping mechanism but rejected that for wayleaves/diversions and Ash Dieback. Our comments in these areas are included in the response to the question 6 of the ENWL specific annex, but in terms of cost assessment, we believe that adding them to our baseline is wholly appropriate. In the case of unlooping and wayleaves/diversions, Ofgem's disaggregated benchmarking removes the adjusted values demonstrating that they are sensitivities rather than forecasts.

The impact of Ofgem's actions in the DD in this regard are twofold; to increase the headline reduction of Totex through cost assessment and to materially distort the composition of our submission such that, when combined with Ofgem's crude approach to allocating allowances, it results in a mismatch of allowances and obligations at a cost category level.

We propose that Ofgem should reverse the normalisations for FD.

Further to this issue on normalisations, we also disagree with the rejection of our company-specific factor[17] by Ofgem. We have commissioned Oxera to consider the positions and justifications from Ofgem for the rejection of our FBP submission and full details of this response can be found in the appendix[18] to this document. It is essential that Ofgem review the content of this report in full but set out a summary of the key elements below.

Ofgem is wrong in its reasoning for rejection

The table below sets out the conceptual reasoning from Ofgem for rejecting our company-specific factor claim and our response to this noting the reasoning why we consider Ofgem is wrong in its summary assessment/justification for rejection at DD.

Table 11: ENWL response to Ofgem justification

Ofgem Justification	Our reasoning and evidence to why this is wrong
Fixed costs are incurred by all DNOs to varying degrees and are not unique to ENWL.	We agree that fixed costs are incurred by all DNOs. The issue is not that these are incurred, but that the level of fixed costs would depend on the size of the DNO group. The Ofgem framework therefore needs to reflect the efficient level of these fixed costs in each DNO's cost allowance commensurate with its size in group terms. Evidence of this was presented in our FBP report[19], where it was set out that scale and cost allocation issues need to properly be addressed and compared in modelling frameworks, and that cost bias exists where they are not. The assessment of fixed costs, the associated economies of scale and ownership-related sharing of costs, is a general modelling issue that economic regulators need to address carefully in their assessment.

[17] 'Additional efficient costs of a small company model'

[18] Oxera (2022), 'The impact of inappropriate modelling of scale economies and shared costs', August, Appendix 1

[19] Oxera (2021), 'Additional efficient costs of a small company model (single licensee operating model)', November.

Ofgem Justification	Our reasoning and evidence to why this is wrong
The DNO group size is not entirely exogenous, given the potential for acquisition and divestment.	A decision to merge or de-merge is not entirely decided by the DNO itself and not entirely endogenous either. Oxera notes that "*As noted in our previous report,*[20] *Ofgem has structures in place that are designed to inhibit the ability to merge freely. Importantly, energy mergers will need to go through a special merger regime similar to that in the water sector, as stated by the new energy security bill,*[21] *which makes the acquisition or divestiture of networks contingent on the impact that any ownership structure change might have on Ofgem's ability to carry out its benchmarking. In other words, with the introduction of the new energy bill, future acquisition and divestment in the energy sector may need to go through an extensive process involving multiple phases of assessment. Moreover, a biased assessment of ENWL and other DNO groups' cost performance in Ofgem's benchmarking—for example, through an incorrect consideration of scale economies and cost misallocation—can affect the outcome of the merger inquiry.*"[22] Therefore, our view is that DNO group size is more exogenous than it is endogenous, and that there are significant benefits to the sector of ENWL retaining its single licensee status.
The wide range of estimates in Oxera's work demonstrates that group fixed costs do not have clear boundaries and are not readily and objectively identifiable.	This argument is disingenuous to the evidence available at the time. The exact data and models to be used in RIIO-ED2 were not yet known or publicly available at the time the assessment was undertaken and when the report was developed. Therefore, the work followed Ofgem's ED2 SSMD positions, in terms of considering multiple model specifications and estimation techniques, as much as possible in determining a robust range of the likely single licensee effect. The analysis, based on multiple model specifications and well-established methods, consistently demonstrated a material downward bias in the cost allowance estimated for ourselves (and other DNOs) should Ofgem mis-specify the modelling relationship between costs and outputs. This range of estimates was derived and presented from an extensive evidence base and is not a reflection of any perceived difficulty in modelling fixed costs, but representative of extensive evidence to prove the existence of such a relationship in the absence of the modelling process/form for ED2. We also note that Oxera highlight that the range presented by Ofgem in key parts of its DD is not dissimilar if not wider to that we presented in our FBP.

[20] Ibid.
[21] For more details, see UK government (2022), 'Energy Security Bill factsheet: Energy network special merger regime', 6 July, https://www.gov.uk/government/publications/energy-security-bill-factsheets/energy-security-bill-factsheet-energy-network-special-merger-regime, accessed 9 August 2022.
[22] Oxera (2022), 'The impact of inappropriate modelling of scale economies and shared costs', August, Appendix 1

Ofgem Justification	Our reasoning and evidence to why this is wrong
Ofgem's proposed modelling is consistent with RIIO-GD2.	GD has a different ownership structure to ED. We note that Oxera has concluded that *"Ofgem has overlooked the fact that its appointed consultant on BSC modelling at GD2 recommended modelling at the ownership group-level for indirect expenditure if Ofgem were to make use of disaggregated models in GD2.*[23] *In addition, Ofgem has deviated from its approach in RIIO-ED1 and DPCR5 where it modelled indirect expenditure such as BSC at the group rather than the individual DNO level explicitly recognising shared costs.*[24] *Therefore, counter to Ofgem's suggestion, there is regulatory precedent for accounting for group-level or ownership-level scale effects and cost misallocation in the cost assessment process."*[25]

Further, we note that no independent empirical analysis has been presented by Ofgem, nor on the face of it any undertaken. Ofgem indicated at our cost bilateral that CEPA supported in its review of our Oxera report provided at FBP. This was confirmed by Ofgem through response to our SQ[26] where it stated that "*CEPA supported Ofgem in qualitatively evaluating ENWL's Singleton claim' and that the 'outcome of this evaluation [is present] in our DD Core Document*". This confirms that the rejection of our company-specific factor claims was conceptual, high-level and limited to qualitative summary arguments contained in a single paragraph and these arguments are unsupported by evidence, empirical or otherwise, as shown in the table above.

<u>Estimation based on ED2 models</u>

Given we now have the models used for DDs, we asked Oxera to reconsider and update the evidence on scale effect and cost allocation issues based on the models that have been shared.

Upon review it was concluded that the models (three Totex and BSC model within disaggregated suite) all fail to adequately account for group-level scale effects within them. Oxera has considered the impact of the failure to adequately account for these and set out that "*the simplest method to account for group-level scale effects in Ofgem's framework is to include variables that can capture group-level characteristics in Ofgem's cost assessment models.*"

Additionally, they note "*It is possible to perform group-level analysis, where cost models are estimated at the DNO group rather than the DNO level (in line with Ofgem's approach to modelling some expenditure items in previous price control reviews). In this way, the group-level scale effect is directly captured in the estimated relationship between scale and expenditure.*"

Given that Oxera has highlighted that the issues are most prevalent in the BSC model and the three Totex models, we set out the impact in these areas in turn below.

[23] See Economic Consulting Associates (2020), 'RIIO-GD2 and T2: BSC and CAI assessment methodology', May.
[24] See Ofgem (2009), 'Electricity Distribution Price Control Review Final Proposals - Allowed revenue - Cost assessment appendix', December, para. 1.70; and Ofgem (2013), 'RIIO-ED1 Draft determinations - business plan expenditure assessment', November, para. 10.48.
[25] Oxera (2022), 'The impact of inappropriate modelling of scale economies and shared costs', August, Appendix 1
[26] ENWL025

Business support models

For BSC disaggregated model Oxera concluded that "*Ofgem's ED2 models confirm that group-level scale has a material impact on DNOs' efficient level of BSCs. We note that the issue of group-level scale affects all DNO groups (to varying degrees), which is to be expected given that the robust treatment of scale or fixed costs is a general modelling issue. Nonetheless, **ENWL is the most materially affected being a singleton**, with a group-level scale effect* [redacted]*, which **amounts to c.** [redacted] **in BSCs alone**.*"

This is based on different methods undertaken to account for group-level scale effects grounded in the existing BSC model namely; including a variable representing the total MEAV for the DNO group to which a DNO belongs, modelled at the DNO level, and separately estimating Ofgem's BSC model at the group level instead of at the DNO level.

Totex models

Oxera have concluded that "*The same issues facing Ofgem's BSC model also affect Ofgem's TOTEX models, which includes direct and indirect costs. The evidence presented in this report demonstrates the presence of group-level scale effects that are unaccounted for in Ofgem's TOTEX models. Given the unequivocal existence of shared costs within TOTEX (e.g. BSCs and other indirect costs) and the scope for group-level economies of scale in general, the impact of Ofgem's omission is greater (in £m terms) in the TOTEX models (between* [redacted]*).*"

This is based on the estimated effect of group-level scale for Totex under two methods for each of the three Totex models (Totex 1, Totex 2 and Totex 3) proposed by Ofgem, namely; including a variable to capture the size of the group to which a DNO belongs (as defined by whichever CSV Ofgem includes in the original model) in the DNO-level modelling, and separately estimating Ofgem's models at the group level instead of at the DNO level.

Given that Ofgem rejected our proposal at DD based on limited qualitative reasoning we urge that Ofgem consider our answer to this question carefully and the wider evidence and conclusions from the report. This should in include our updated evidence on the impact and in turn make the appropriate company-specific adjustment or its modelling amended suitably based on the evidence contained.

The adjustment could be made through the use of pre-modelling adjustments representing/reflecting the estimated impact which we have quantified, or, as a minimum, through modelling updates changes that reflect the impact directly through, for example, changes to the BSC model for ED2.

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

We agree with the desire of Ofgem to include Totex models in its assessment of companies' efficient costs.

However, we note that the ED2 models perform relatively poorly against the model development criteria set out by Ofgem and when compared with the ED1 and GD2 models used. It is therefore not appropriate to set the efficiency benchmark at a more stringent level than ED1 based on this worsening model quality. We set out our more detailed response to this issue in Q108.

Ofgem should carefully consider how the Totex models perform at FD (e.g. in light of data updates, changes to pre-modelling adjustments and wider model changes), with a focus on the economic, operational and statistical quality of the models. We set out our views and representations on this in response to Q63 and below in direct response to this question.

We accept that Totex benchmarking has a significant role to play in cost assessment and a range of different Totex models can give different perspectives on the same cost base. Given the shortcomings of the approach, it can never be the only assessment techniques however, and we are pleased in principle to see that Ofgem have maintained the weighted approach from ED1. We currently see no justification for differential weightings between Totex models and strong evidence would be needed for different weightings to be applied.

In developing the Totex models, the choice of cost driver(s) are important. As is the need to ensure that different Totex models are suitably differentiated from each other. Careful consideration also needs to be given to appropriate cost exclusions where the selected cost drivers within the Totex models do not explain the level of costs in a specific area.

To that end we suggest that Ofgem give consideration to its composition of both bottom-up and top-down CSVs. We discuss each in turn below.

Bottom-up CSV

We have concerns that, as currently specified, the bottom-up CSVs make use of cost drivers which suffer from significant issues of endogeneity that currently set perverse incentives. This is particularly of note where ‘total faults’ and ‘total ONIs’ are used. We view that Ofgem should carefully consider the use of these cost drivers in the bottom-up CSV and assess whether alternatives are appropriate for use. We would suggest assessing what alternatives might be possible, for example, from a statistical point of view, by mapping drivers to the cost area they are most strongly correlated with but crucially with endogenous drivers removed.

Alternatively, and as a minimum, Ofgem should revert to the use of mapping for bottom-up CSV used at ED1 which we view as being more appropriate.

Top-down CSV

For top-down CSV we have the same conceptual issue as for bottom-up in that the use and weighting of endogenous drivers gives rise to statistical and incentive issues if improperly considered. This is because it may incentivise DNOs to increase its values for these cost drivers to the detriment of consumers. Conversely, DNOs that have incurred significant expenditure to reduce the value of some of these cost drivers (to the benefit of consumers) will be penalised in the cost assessment process. For example, using activity-based cost drivers does not take into account the expenditure on inspections, maintenance and repairs accruing to companies to keep the number of faults low. In addition, faults can cause significant disruptions to consumers. The current modelling approach thus implicitly incentivises DNOs not only to choose an inefficient allocation between preventing and fixing faults, but also to cause negative externalities affecting their customers.

We note that Ofgem has dismissed concerns[27] of perverse incentives in the DD as neither the modelled costs nor the efficiency score rankings obtained from their models are correlated with faults. This approach is, however, insufficient to rule out that faults are endogenous, and we urge to examine the issue more carefully. If, for example, all DNOs increase their fault rates by a similar rate (e.g. ca. 10 percent), this would generally not be detected in the correlations tests that Ofgem has conducted.

[27] Ofgem (2022), Draft Determination: Core Methodology document, June, page 331.

Overall comments on the Ofgem disaggregated modelling

We note at a high-level that the aggregated outcome of the disaggregated assessment produces a very different outcome and company order than the Totex approach, including the conclusion that all DNOs are short of the notional constructed efficiency frontier.

Ofgem uses a combination of unit cost models, regression analysis and qualitative assessments to assess companies' expenditure in the disaggregated modelling, although the majority of the activities are assessed through unit cost analysis.

The benchmark in these models is typically the median (in the unit cost models) or the average (in the regression analysis). We note that the benchmark is calculated using an inconsistent mix of historical and forecast data, such that the benchmark does not represent the median of the forecast data in all cases.

Furthermore, there are a number of material errors in the disaggregated modelling suite as noted in the specific responses below.

Ofgem states that it did not apply an additional efficiency challenge in the disaggregated modelling because it:

> *"consider[s] [that the disaggregated models]* ***already capture a sufficient degree of DNO cost efficiency*** *given the substantial technical input into our disaggregated modelling stream. Moreover, by not computing a catch-up efficiency challenge based on disaggregated modelling results, we also reduce the risk of interpreting differences in business strategies and/or cost allocation approaches as differences in efficiency [emphasis added]"*[28]

However, describing the level of challenge as 'sufficient' is misleading. Not a single company is assessed to be efficient in the disaggregated modelling, such that the level of challenge is significantly greater than in the Totex models, or even what is feasible. That is, the efficiency challenge applied is beyond the frontier as even the frontier network is assessed to be 2 percent inefficient. In other words, if Ofgem were to apply a glidepath from the UQ to the 85th percentile as determined in the Totex models, companies would receive an uplift of more than 6 percent.[29]

As Ofgem typically applies a median or an average benchmark, one would expect that roughly half of the companies would be estimated to be efficient in the disaggregated models and roughly half to be inefficient. The observation that not a single network is assessed to be efficient in the disaggregated models indicates that Ofgem's disaggregated models are overly stringent, and could be explained by:

- Errors in the disaggregate analysis, some of which have been acknowledged by Ofgem;
- Ofgem's inconsistent estimation of the benchmark across expenditure categories;
- The relative poor performance of individual cost models;
- The inability of the disaggregated models to account for trade-offs, cost allocation and substitution effects.[30]

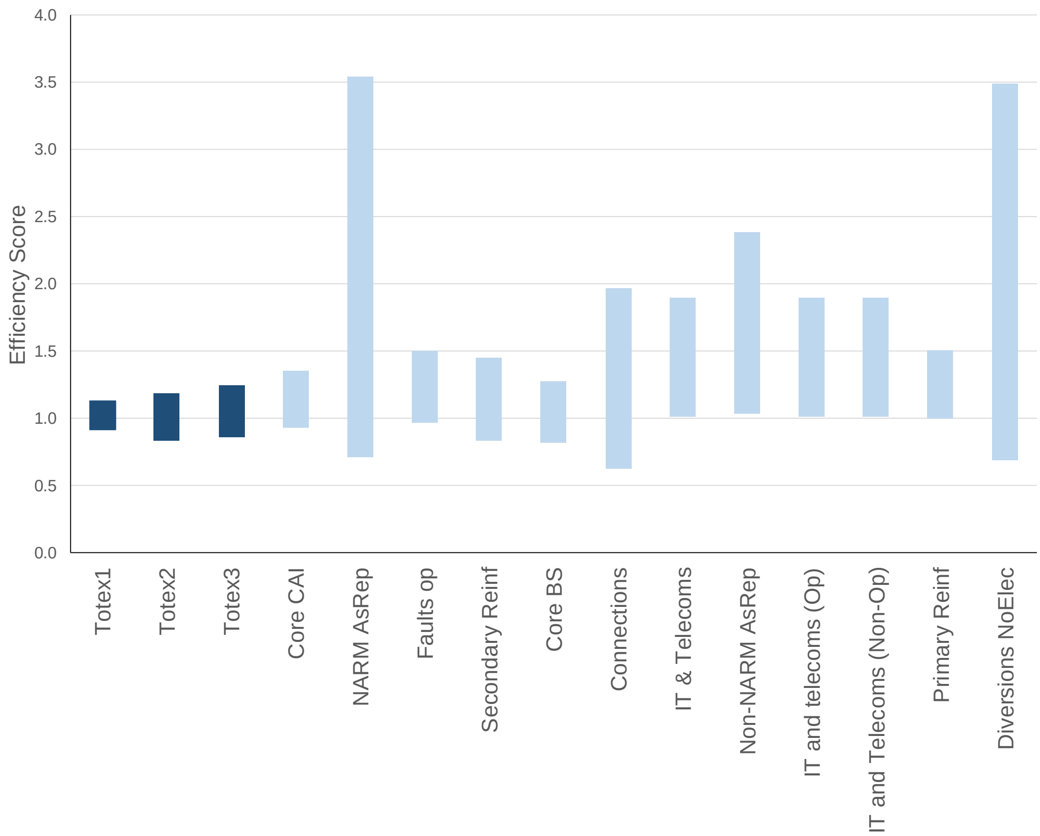
[28] Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', June.
[29] See Ofgem (2022), 'CostAssessment_File.xlsx', sheet 'Out_Efficiency'.
[30] Indeed, Ofgem also notes this as a concern with the disaggregated models. See Ofgem (2022), 'RIIO-ED2 Draft Determinations – Core Methodology Document', June, para. 7.133.

Whilst disaggregated models can be a valid tool for cost assessment, they should be modelled robustly, and results should be validated in terms of statistical and engineering properties of the models and model outcomes (individually and 'in the round').

To compare different models, we examine the width of the range of efficiency scores, i.e. the difference between the most and the least efficient DNO, as well as the standard deviations of these efficiency scores by model. A wide range and high standard deviation in the efficiency score would indicate a high level of uncertainty (e.g. due to cost allocation, omitted variables or disregarding of trade-offs) in the model outcomes and not entirely inefficiency.

The graph below shows the ranges of efficiency scores for the three Totex models in dark blue and the ranges of efficiency scores for ten disaggregated models in light blue. We calculate efficiency scores, as Ofgem does, by dividing the submitted costs by the modelled costs during ED2 for each of the 14 DNOs31. The ten disaggregated models shown in the figure reflect the largest cost activities, as measured by submitted costs, jointly representing 70 percent of the total costs submitted for RIIO-ED2 and are sorted in descending order of magnitude. We compare these to the Totex models, which include the costs modelled through these aggregated models.

Figure 8: Efficiency Score Range for Totex and disaggregated Models



It is evident that the disaggregated models (light blue) produce much wider ranges for efficiency scores than the Totex models (dark blue). All of the ten disaggregated models have wider ranges for the efficiency scores than any of the Totex models. The average width for the Totex models is 0.32, whereas the average width in the disaggregated models is 1.14 (excluding outliers, weighted by cost

[31] Note that this means that a DNO with a high value for the efficiency score is *less* efficient than a company with a low value.

share of total), which is more than three times as high as the average for the Totex models[32]. This indicates that there is significantly higher uncertainty and volatility in the disaggregated models.

The subsequent questions in this response focus on the individual components of the cost base which form the elements of the disaggregated modelling process. Our comments in each regard relate to the construction and function of the relevant disaggregated model only. In terms of allowance-setting for each area, the disaggregated model outcome is actually a minor element in the DD due to Ofgem's adoption of a high-level allocation of adjustments across all cost categories, irrespective of the disaggregated model outcome for each area. We fundamentally disagree with this approach which produces distortions at the activity level and also divorces the proposed allowances from the outcome of the relevant disaggregated analysis. Further details are provided in our response to Q111.

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

Use of £/MVA analysis is very crude in this area where specific proposals often have highly individual network circumstances to consider. We also highlight that Ofgem's Engineering Hub agreed with our submitted EJPs in this category which set out a level of detailed analysis and costing, far beyond a simple ratio analysis. As such, we believe our costs should be accepted in this area.

Our submission also included significant discounts for the assumed impacts of flex and smart solutions. We note that we were the only DNO to do so. As set out in the DD, Ofgem reduce our costs on the basis of unit cost assessment, but do not also adjust our discounts. If Ofgem continue with the unit cost approach to FD, the same adjustments need to be applied to the discounts as the gross costs as they are in the same currency.

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?

This area is substantially driven by a small number of specific projects which are bespoke to their particular network circumstances. We are pleased that our EJPs in this area were accepted by Ofgem and suggest that this validates our forecasts.

Using historic average costs of capacity can be distorting due to the specific circumstances of individual projects.

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

This analysis highlights the inappropriateness of Ofgem adding back our unlooping uncertainty volumes from table M13 as they are all subsequently benchmarked away. The spread of values calculated using the unloop per EV/HP function shows that this is an unreliable factor to scale company volume forecasts by as it does not take account of issues such as legacy housing stock design and network configurations etc. Of note is that two DNO Groups (five licensees) do not have any volumes at all in this category showing inconsistency of treatment within the sector and hence the inappropriateness of applying a derived ratio.

[32] We define models that produce efficiency scores equal 0 or greater than 10 as outliers. These models reflect less than 6% of total submitted costs for ED2. We note that the average without exclusion of outliers and weighting would be even higher.

On unit costs, as per our response to question 68, simply taking asset replacement costs derived from table CV7 analysis does not reflect the variation and complexity of unlooping scenarios, as set out in our submission. We suggest that a more detailed unit cost schedule is developed, aligned with the work on developing the associated volumes driver in this area, as there needs to be consistency across both baseline and uncertainty mechanism cost treatment.

In the other areas of CV2, the analysis using £/MVA and £/km functions looks broadly appropriate given the high volumes in this area (as opposed to CV1 Primary reinforcement which is much more bespoke to specific circumstances, hence the volume of EJPs in this area). However as per our response to question 4, we highlight the need to consider the materially different overhead and underground proportions across DNOs in the construction of 'circuit' unit rates. Again, this needs to be aligned across the development of baseline allowances and the calibration of the associated uncertainty mechanism.

As per our response to question 66, we included a substantive discount on future costs based on the assumed impact of flexibility, and to ensure no double count with our C2 submission. We note that Ofgem have simply included this in the model outcome on an unadjusted basis. Should there be any unit cost adjustments applied in this area for the FD, they need to be included consistently across the assessed costs and the discount function.

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 agree that the costs for capacity constraints are broadly appropriate but need to be;

1) Set at an appropriate level, and
2) Need to be consistent between baseline allowances and the calibration of the associated uncertainty mechanism.

As per our response to question 67, care needs to be taken in the construction of 'circuit' unit costs by voltage to reflect the materially different overhead/underground mixes between the DNOs.

For the proactive service reinforcement, we do not agree that taking three unit costs from a CV7 Asset replacement-derived analysis appropriately captures the range of circumstances encountered when unlooping properties. For example, it may be necessary to undertake work on the mains cable itself, transfer overhead services to underground etc. In addition, substantial reinstatement costs for property driveways etc. may be incurred. The CV7 volumes are almost always either incidental to other work or simply reflect like-for-like replacement of existing equipment.

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

We note that Ofgem exclude our unit costs from the overall costing comparison (as they are very low), but then do not include all of our HV Fault level costs due to using a comparison with ED1 and applying a 'lesser of' ratchet.

The mix of work between ED1 and ED2 is fundamentally different as shown by the change in volumes towards the end of ED1. An overall ED1 average unit cost is null and void for comparison with ED2 and we believe the programme should be fully funded at the highly efficient costs submitted which include the deployment of our innovative fault level re-rating programme at HV.

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

This is a modelling judgement by Ofgem and sets a precedent for omitting data at significant variance to the rest of the sector. We suggest that this sets a precedent that should be considered in other areas, particularly where there are more limited data points on unit costs and/or inconsistency of the definition of a unit in areas of unit cost analysis.

It is noted in the methodology that the approach for us is unique. Given that the costs are comparable between DNOs, but the volumes for ourselves significantly higher than others, a bespoke approach is required. However, the differences emerge from 2021 onwards, five years into the ED1 period. The use of the combined ED1 and ED2 period for evaluating our unit costs is therefore inconsistent, with the latter unit cost being 50 percent higher than the former.

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

Ofgem is proposing a change to the methodology which reintroduces potential distortions that were deliberately changed for ED1. The move back to MPANs rather than projects introduces two potential distortions;

1. It disadvantages DNOs where there is competition;

    - DNO A with low competition would report £100,000 of reinforcement and 1,000 MPANs that they connect - giving a unit cost of £100/MPAN
    - DNO B where exactly the same work was done would report the same £100,000 of reinforcement but only 1 MPAN for an IDNO connection – giving a unit cost of £100,000/MPAN

This example was why the number of projects was added to the annual reporting and used as a dominator as it gives the same result for both DNOs

2. Doesn't take account of add loads;

    - This is possibly a second order effect, but if we have a project that requires reinforcement but is an add load then there is 1 project but 0 MPANs, so that there are costs in the numerator but none in the dominator.

Again, this issue is removed with the use of number of projects as the dominator.

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

We have not included any of these costs in our FBP. Ofgem's approach of conducting a qualitative review appears appropriate and we note that all company submissions have been accepted on this basis. We suggest that there are other areas of the cost assessment process where a similar approach should be adopted (e.g. IT capex), rather than a high-level ratio model used to derive a disaggregated cost outcome.

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

For areas not covered by NARMs, we accept that a panel data approach is appropriate to identify the likely scale of future replacement requirements, including run-rate analysis, survivor curve modelling etc. We note the Engineering Hub's comments on a small number of our EJPs in this area and look forward to discussing these bilaterally, supported by additional evidence for our submitted volumes.

For the categories covered by NARMs, we are deeply concerned about the disconnect introduced by Ofgem in the assessment of the risk points and the volumes required to generate the risk points. Ofgem state that the toolkit of approaches is consistent with that used for RIIO-ED1, but risk point analysis was not available for the RIIO-ED1 assessment due to the absence of the CNAIM methodology.

Risk point analysis should be the prime vehicle for assessing company proposals in this area as it relates to an overall portfolio of interventions which can be assessed on a collective basis. It also enables assessment of the combined refurbishment and replacement proposals in this area to ensure efficient costs across the whole NARMs submission.

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

We have discussed with Ofgem the mis-translation of our submitted EJPs for NARMs activities. These include forecasts for the relevant refurbishment activities (CV9 Refurbishment SDI); however, the comments on these EJPs have been taken as applying to CV8 (Refurbishment non-SDI) and volumes zeroed out as a consequence. We believe from the Ofgem Costs team that this issue has been acknowledged and will be corrected for FD.

We have also highlighted to the Ofgem Costs team a specific error which zeroes the unit cost for protection activities. This applies to all DNOs and again we believe has been acknowledged and will be corrected. We are pleased to note that our EJP for protection was accepted and the volumes allowed (at zero-unit cost) but concerned to note on the Engineering analysis that it records no EJP as having been submitted for this activity.

We have also highlighted further errors in the oil cable categories and issues arising from inconsistent use of terminology, e.g. typos in the category name of 33kV Transformers (GM) in table CV9.

In terms of NARMs, we are concerned that separate analysis of replacement and refurbishment activities does not probe the efficient split between the two, i.e. higher volumes of refurbishment may be more efficient overall, but potentially benchmarked away as not consistent with run rate analysis.

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

We agree that the approach adopted for DDs is reasonable. By expressing the civils costs as a proportion of the relevant submitted overall replacement costs, the ratio should not change significantly through time, although the volumes to which the ratios are applied will due to programme fluctuations.

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

We do not think that a unit costing approach is appropriate for Condition Based Civil Works due to the lack of a consistent definition of units at each voltage. This is evident in the wide variation in volumes and unit costs across the DNOs. As a consequence, the unit cost data is too variable to set reliable benchmarks and the simple application of crude ratios to act as comparable volume assessments leads to inappropriate adjustments.

For ENWL, these adjustments halve our forecast to a level well below that we consider consistent with discharging our statutory obligations in this area. We suggest applying the ED1 run rate to this area.

Inspection of the individual asset types throws up a number of illustrations of the disparity in the data sets. For example, looking at the unit costs submitted for work on Cable Bridges.

Table 12: Costs for work on Cable Bridges

Cable Bridge Unit Costs		Submitted Unit Costs	Allowed Unit Cost	Difference
ENWL	ENWL	[redacted]	12.3	[redacted]
NPg	NPGN	[redacted]	12.3	[redacted]
	NPGY	[redacted]	12.3	[redacted]
WPD	WMID			
	EMID			
	SWALES			
	SWEST	[redacted]	12.3	[redacted]
UKPN	LPN	[redacted]	12.3	[redacted]
	SPN	[redacted]	12.3	[redacted]
	EPN	[redacted]	12.3	[redacted]
SP	SPD	[redacted]	12.3	[redacted]
	SPMW	[redacted]	12.3	[redacted]
SSE	SSEH			
	SSES			

The range of unit costs from [redacted] per activity up to [redacted] per activity clearly illustrates the disparity in the types of work that DNOs are planning to deliver. This is further underlined by the fact that within the UKPN group the unit costs range from [redacted] per activity to [redacted] per activity. For Scottish Power, one unit cost is almost double the other. For unit cost benchmarking to be effective the different DNOs need to be delivering comparable work. In this example, and for other asset types, it is evident that this is not even true within DNO groups.

Similarly, the different types of work that DNOs are planning, ranging from fixing doors to replacing roofs and fences, does not lend itself to volume benchmarking. Again, there are many examples but perhaps the most extreme is for HV Outdoor Substations.

Table 11: Volumes for HV Outdoor Substations

HV Outdoor Substations		Submitted Volumes	Allowed Volumes	Difference	Percentage change
ENWL	ENWL	2,105.0	1,888.7	-216.3	-10%
NPg	NPGN	855.0	663.6	-191.4	-22%
	NPGY	1,570.0	281.2	-1,288.8	-82%
WPD	WMID	2,361.0	2,242.2	-118.8	-5%

HV Outdoor Substations		Submitted Volumes	Allowed Volumes	Difference	Percentage change
	EMID	1,288.0	979.3	-308.7	-24%
	SWALES	373.0	546.2	173.2	46%
	SWEST	630.0	486.3	-143.7	-23%
UKPN	LPN	558.0	558.5	0.5	0%
	SPN	2,640.0	4,354.8	1,714.8	65%
	EPN	3,510.0	6,861.0	3,351.0	95%
SP	SPD	2,380.0	3,142.7	762.7	32%
	SPMW	195.0	309.5	114.5	59%
SSE	SSEH	695.0	1,299.4	604.4	87%
	SSES	2,945.0	6,094.2	3,149.2	107%

Engineers in individual DNOs have designed detailed programmes of work based on the known needs within those DNOs. The method of applying a median percentage of activities per substation or asset type leads to a massive distortion in the allowed volumes, with three DNOs being 'allowed' around twice what they asked for, and one being allowed half.

When all these changes are brought together it results in a widely changing set of disaggregated allowed costs. The table below shows the movement of costs from submitted to allowed, with the changes calculated as follows:

- Changes due to unit costs – this is the change that would arise if all DNOs were awarded the volumes they asked for, but were given the median unit costs
- Changes due to volumes – this is the change that would arise if all DNOs were awarded the unit costs they asked for, but were given the volumes based on the median percentage of delivery
- Changes due to both – these are the costs of delivering the difference in volumes at the median unit cost.

Table 13: All Condition Based Civil Work Costs

All Condition Based Civil Work Costs		Submitted Costs	Changes due to unit costs	Changes due to volumes	Changes due to both	Allowed costs
ENWL	ENWL	26.9	0.9	-12.0	-1.5	14.3
NPg	NPGN	10.9	-1.1	-1.8	0.1	8.2
	NPGY	18.6	-2.6	-1.2	-0.7	14.2
WPD	WMID	27.4	-13.3	-3.6	1.8	12.3
	EMID	20.2	-7.4	6.7	-1.7	17.7
	SWALES	10.8	-4.2	2.8	-1.1	8.4
	SWEST	10.1	0.1	3.2	-0.7	12.7
UKPN	LPN	7.4	0.9	11.3	-5.9	13.7

All Condition Based Civil Work Costs		Submitted Costs	Changes due to unit costs	Changes due to volumes	Changes due to both	Allowed costs
	SPN	11.0	4.7	4.2	-2.9	17.0
	EPN	14.7	1.5	20.7	-5.0	31.8
SP	SPD	18.5	-6.0	8.8	-5.3	16.0
	SPMW	14.1	-1.4	8.1	-4.1	16.7
SSE	SSEH	6.2	-0.3	5.0	-0.3	10.6
	SSES	21.2	-4.7	6.9	0.1	23.4
All DNOs		**218.0**	**-33.0**	**59.3**	**-27.3**	**217.0**

Whilst the industry total allowance is only £1m below what companies asked for the dramatic changes due to unit cost and volume assessment illustrate that this methodology is deeply flawed.

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

Utilising a unit cost approach in this area is fraught with difficulty due to the lack of any standard definition of units, and the variability in what is covered by 'claims'.

However, the most significant issue is that this is another area where Ofgem have brought over a high level upper end projection from table M13 in our submission without any associated volumes. As a consequence, the key areas subject to the uncertainty (i.e. LV & HV woodpole claims) are counted as zero volumes and £37.6m of our ported across costs simply fall out of the disaggregated modelling as no associated volumes are credited.

We propose that Ofgem unwind the adjustment to our submission, however if it is retained, then we will need to supply the associated volumes to correct this significant modelling error.

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

We agree with the retention of a re-opener mechanism in this area.

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

We fundamentally disagree with the level of analysis in this area and also refer Ofgem to our appended letter[33] on this topic. Ofgem is wrong in using an aggregated approach to all three categories and then applying a 13-year average MEAV function as this does not reflect the costs of meeting the challenges of ED2 in this area. We note that Ofgem's DD states that it agrees with company proposals for data and digitalisation, but the accompanying cost assessment process fails to reflect this in its mechanics.

This issue is particularly stark in the case of LV monitoring which was only re-classified as an Operational IT process later in the BPDT development process. As such, it clearly has no equivalent in the ED1 historic data which is used for the analysis.

[33] ENWL (2022), 'ENWL input to Ofgem on Data, Digitalisation, Cyber and IT costs'- Letter, August, Appendix 3

Ideally, Ofgem should undertake a detailed, specialist review of company proposals in this area which appropriately tests their validity and efficiency, and we were surprised at the crude disaggregated approach of Ofgem's revealed in the DD. If Ofgem maintain the models as presented, we propose that the IT and OT capex elements are assessed against ED2 data only, with the LV monitoring aspects removed for separate assessment. We have provided a specific EJP for this purpose which the Hub concluded "*presents several credible drivers for the installation of the LV monitoring devices, as well as associated benefits"* and hence suggest these costs are allowed as submitted.

We would also note that this question response has links to our views on question 19 of this response which covers our detailed views on the related re-opener in this area.

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

We observe that Ofgem has split this activity into two elements. The majority of the bespoke items are covered by specific EJPs and we are pleased to note that they have been accepted and included in the model outcome.

For the standard activities in the top part of the table, we note that Ofgem has attempted unit cost modelling and concluded that it is too variable to rely on. We agree with this conclusion. The alternative promoted is to revert to high level MEAV analysis and this results in significant (~50 percent) reductions to our proposals in this area. Given that these activities are driven by safety compliance, we do not consider MEAV to be an accurate reflection of company obligations and a greater degree of qualitative analysis should be undertaken in this area.

In particular, we have proposed a programme of LV earthing upgrades which appears to be substantially different in quantum to other DNOs who look to have solely included routine earthing requirements in the upper table. Our proposals in this area were covered by an EJP on which the Engineering Hub concluded "*We believe that the EJP provides sufficient justification for the needs case and optioneering*". We propose that this should therefore be moved to the lower part of the table with the other EJP-justified programmes and included in the baseline allowance.

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

We think Ofgem's approach in this area is appropriate. Volumes are driven by compliance requirements and unit costs should be broadly comparable between DNOs due to the high volumes involved enabling typical and representative solution mixes being included.

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

We are supportive of the re-opener proposals in this area but highlight that our forecast costs for ESR compliance relate to additional control room resilience rather than capital investment in network assets. As such, our costs form part of our Closely Associated Indirects forecast and should be separately assessed as part of that analysis.

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

We agree that funding any explicit IIS-focused investment would potentially result in customers paying for the same improvements twice.

We are disappointed, however, to note that Ofgem has rejected our programme to improve reliability and resilience for vulnerable customers which was included in this category in the BPDT (as there was no other option). This programme is aimed at ensuring those who suffer the greatest impacts of power cuts are protected from them happening in the future through a programme of enhanced network resilience through reconfiguration. As such, these locations may not currently experience poor reliability and hence the investment will have minimal impact on near-term IIS performance.

Customer support for this initiative was very strong in our willingness-to-pay research as customers were supportive of us undertaking further work to protect the most vulnerable from the effects of power cuts as a key component of our overall vulnerable customer strategy.

We provide further details on the justification for this programme in our response to question 3 of the ENWL Annex.

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

We are pleased to note that Ofgem accept our proposals in this area and suggest as a consequence that they should be fully funded in the FD.

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

From our own experience, the costs of flood mitigation can be highly variable by site. In addition, most DNOs will have completed the majority of their flood defence programmes in DPCR5 and RIIO-ED1 hence the sites proposed in ED2 may not be reflective of historic activities.

However, we agree that if a unit costing approach is adopted, it should be on a per activity rather than per customer basis as the number of customers supplied has little to do with the practical scope of works required on site.

Where DNOs have particular sites with higher costs due to unusual configurations etc., then a follow up qualitative adjustment may be required where justified; however, we have not identified any such instances for us in the DD.

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

We disagree with the analysis completed at DD which uses an inappropriate conflated unit cost function. RLM comprises significantly different activities (inspections, repairs, monitoring, replacement etc.) which cannot simply be aggregated.

We are pleased to note that Ofgem have issued a supplementary data template based on our suggestions which we expect will lead to a more sensible assessment of this area for FD which includes a disaggregated unit cost analysis.

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

We agree with Ofgem's proposals in this area and also that, in order for the revised WSC scheme to be effective, the requirements need to be set at a high level. We look forward to continuing to work with Ofgem on the relevant guidance in this area.

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

Whilst we are pleased to see our volumes accepted, we disagree with Ofgem's approach to unit costing in this area. It is clear that there is a mismatch in activity reported by DNOs on this table with only ourselves and SPEN having proposed proactive programmes of high loss transformer replacement with the full costs included under this activity. The use of an 'Expert View' unit cost derived from table CV7 analysis fails to consider that the losses mitigation programme is aimed at the largest (and hence most expensive) HV transformers as this is where the losses benefits are highest and NPV greatest based on the CBA. CV7 unit costs will be predominantly driven by the smaller capacity units that make up the bulk of the inventory.

Given the paucity of comparators in this area, we believe our programme should be funded at the costs submitted which the relevant model shows are lower than our equivalent for ED1.

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

On the non-PCB element of the environmental activity, we note that Ofgem are selective regarding which aspects are assessed using unit costs and which are reviewed separately. We are particularly concerned about the use of unit costs for the 'Contaminated Land Clean Up' category where the outcome for ENWL is funding at 10 percent of the required level. As set out in the commentary to our submission, our programme is based on five specific sites following environmental survey. These works are extensive and specific. Given the variability in this category (two DNO groups submit no costs at all), we suggest these costs are separately assessed and refer Ofgem to our commentary for table CV22 for further details.

We also note the inclusion of undergrounding for visual amenity within the disaggregated benchmarking. This would appear to be an error – it appears that Ofgem exclude the category from application of ongoing and catch up efficiencies, but it still catches reductions based on the overall cost assessment outcomes. This is incorrect as this has nothing to do with customer WTP values and was not included in the ED1 approach. For FD, Ofgem should carry forward the ED1 process and treat this category completely separately from cost assessment as a bolt-on UIOLI allowance.

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

We agree that PMT replacements due to PCBs should be subject to a volume driver mechanism and look forward to working with Ofgem on the details of its design.

In terms of the other PCB elements, we are supportive of the inclusion of testing and GM transformer replacement costs within baselines, however, due to an error in the modelling, no costs are included for the latter for us.

As Ofgem unilaterally moved our PCB costs from table M13 to adjust our submission, the £2.6m of costs we have included for GM transformer replacements were not accompanied by any volume forecasts, so we receive zero volumes for this activity. The unit cost applied is also derived from a single DNO Group's data (UKPN) and we suggest does not represent the true cost of replacing a GM transformer (please compare with CV7 assessed costs for the same activity, or the 'Expert View' costs applied in the context of Losses assessment) and hence also needs review for FD.

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

Given that company property portfolios are generally relatively static across price control periods, and their operating boundaries don't change, the use of MEAV as a modelling function would seem broadly appropriate.

Qualitative assessment of the C5 (Non-Op) element is also required however, as many DNOs have included proposals for transforming some of their existing property estate as part of their Net Zero actions/EAP proposals. Consistency is required between Ofgem's assessment of relevant EAP commitments and the associated funding outcome from the cost assessment process.

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

Use of a RIIO-1 plus RIIO-2 data period fails to reflect the increasing costs in this area due to the need to replace first generation smart devices. These are relatively new assets in the inventory and hence will not have equivalent values in RIIO-1. We note that 12 of 14 DNOs forecast increases in this area and the two with small decreases are coming off the back of the largest spend per DNO on a cost/MEAV basis in ED1, reflecting a different investment cycle.

As a consequence, we suggest that forecast costs are assessed in this area, without the use of historic trend analysis.

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

This area is similar to Property costs where the overall size and function of the fleet is unlikely to change significantly in the short-term hence a long-run modelled outcome may be appropriate. We highlight however, that this area also includes company proposals for fleet electrification which forms part of DNO Net Zero actions/EAP commitments. DNOs are also responding to wider initiatives such as Clean Air Zones which are bringing additional requirements in RIIO-ED2. As such, additional qualitative analysis may be required to assess the incremental costs in this regard, also considering potential reductions in the associated indirect costs category (reduced maintenance requirements, fuel costs etc.).

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

We agree with the retention of the HVP mechanism for RIIO-ED2 and consider that its re-scoping to cover non-load projects only may be appropriate, subject to clarity of treatment of equivalent load projects within the range of load uncertainty mechanisms.

We agree that re-opener window(s) within period is appropriate to cover off the uncertainty over scope and timing that may exist at the time of the FD and look forward to working with Ofgem on its definition as part of licence drafting.

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?

Whilst we agree with the principle of a "*high value*" threshold, we consider that the value of £25m proposed is too high for application in ED. This can be seen by the very limited number of projects in this category for ED1 and the fact that no new projects qualified during the re-opener window in ED1. Setting a threshold too high may result in projects needing to wait until ED3 which may not be in customers interest.

We proposed in our business plan a threshold of £18m as we suggested that this was more representative of a high value project in ED, and still maintain that a lower threshold better reflects the reality of a HVP in ED.

Should Ofgem consider that £18m is too low, then we propose an alternative of £20m. We consider that HVPs merit the additional transparency and scrutiny that such a regulatory mechanism brings and also ensures that large projects with a clear justification that come forward in the period do not have to unnecessarily wait for the arbitrary deadline of a new price control.

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

This is a significant cost category and we note Ofgem's comments in the DD regarding different approaches to modelling and the relative strength of their outcomes. We note from reviewing DNO input data that the volume forecasts are significantly different between faults and ONIs for most DNOs, with the former remaining stable through RIIO-ED2 and the latter exhibiting a significant increase for many DNOs. The reasons for the latter include changes to the smart metering arrangements, the introduction of proactive fault location approaches (which are recorded as 'abortive visits' if no work results) etc.

This is an issue if Ofgem simply allocate an overall Troublecall assessed outcome into the two component categories using a percentage basis. For ENWL, the ratio used is 90 percent Faults / 10 percent ONIs which produces opposite outcomes in the disaggregated analysis (higher costs than forecast for Faults, significantly lower for ONIs). From our own data analysis, we calculate the relevant ratio to be 77 percent Faults / 23 percent ONIs and suggest that this calculation needs to be reviewed ahead of FD to ensure a more appropriate balance of allowances across the categories.

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

The proposed approach using industry median cost is logical, as the trends in tree cutting costs and volumes are similar for the majority of DNOs over ED1 and ED2 and the requirements are broadly consistent across the periods. However, although the outcome for us is broad acceptance of our forecast costs, we note the wide range of adjustments in this area (EPN assessed costs are almost double their forecast whilst SSEN's are almost halved) which suggests that there is significant volatility in the input data which needs to be reviewed ahead of FD.

We also note that the issue of ETR132-related costs in particular is included within the storm Arwen action plan and any additional requirements this area will need to feed into the proposed storm Arwen re-opener mechanism in RIIO-ED2. We provide further detailed views on the proposed storm Arwen re-opener in response to question 3 of the Overview document.

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

We agree that these costs are removed from ex-ante allowances and funded through an UM.

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

We believe that this assessment places excessive reliance on MEAV (the majority of MEAV is comprised of assets which do not require inspection or maintenance, e.g. buried cables), and that the use of a combined RIIO-1 plus RIIO-2 data series fails to reflect the increasing costs in ED2 of inspecting, maintaining and repairing newer types of equipment which were installed in ED1 and for which no historic Repair and Maintenance costs have been incurred, e.g. smart devices.

Continued reliable operation of such equipment is a fundamental building block of future smart grid operation and enables its more efficient operation. We have been in the vanguard of smart device rollout at scale and so will be experiencing the associated increase in future inspection, maintenance and repair costs earlier than other DNOs.

We also highlight the change in treatment of cut-out inspections in RIIO-ED2 and the interface with the smart metering rollout programme. As set out in detail within our FBP (it forms one of our high-level outputs – O9), we propose to implement a targeted sample-based proactive cut-out inspection regime within ED2 to ensure that we are appropriately managing cut-out replacements based on high quality inspection data. This regime will supersede that in place in ED1 where the cut-out checks undertaken as part of the smart meter intervention programme provide equivalent insight into equipment condition. With the run-down of the smart meter programme, and the reduction in meter operator visits, we have identified that we need to undertake our own programme of proactive inspections which has been estimated at a cost of £6m over RIIO-ED2. As this has no precedent in the RIIO-ED1 data, we believe this should be separated out from the rest of the inspection costs, assessed separately, and added back in to allowances.

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

We disagree with the approach to modelling Dismantlement costs. It is clear from the data that reporting practice varies significantly in this area hence the panel data on costs cannot reliably be used for inter-DNO comparisons. Given that the two largest DNO groups record minimal costs, the median per MEAV is set so low that 57 percent of DNO forecasts in this area are rejected.

We suggest for FDs that a run rate function is used to ensure consistency with each DNO's current operating and reporting practice and consideration given to a review of reporting practice in this area in ED2 to ensure greater commonality in the future.

In principle, we agree with the approach on Substation Electricity as this should be a more commonly-incurred cost but again note wide diversity in reported costs by DNO suggesting that further work may be required on commonality of reporting in this area.

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

As set out in our response to question 5 of the Overview document, we disagree with the removal of the volume driver for Smart Metering costs in RIIO-ED2 due to the continued uncertainty over the smart metering rollout in our area. This uncertainty also includes the continuing issues with smart metering-related communications in our area.

Relatedly we agree with Ofgem intent to continue with pass-through treatment for DCC costs and Smart Meter related IT costs.

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

The use of long-run regression analysis has a role to play in the assessment of CAI costs and how these change through time. We highlight however, that the use of a time series primarily weighted to history does not fully reflect the costs of responding to future challenges. An example of this is the outcome for Operational Training where the recruitment, training and upskilling requirements are significantly increased in ED2 over ED1 due to a combination of workload increases to accommodate Net Zero and the age profile of the existing DNO (and contractor) workforce. In this area, ED2 costs should be assessed independently of ED1 actuals as part of DNO's delivery plans.

Also, as highlighted in our response to question 82, our ESR compliance costs have been included in this category as they relate to deeper Control Room resilience, rather than network asset investment, building on our Black Start compliance programme in ED1. As such, these costs should be separated out from the CAI assessment, reviewed and added back in.

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

We strongly disagree with the approach for business support costs (BSCs) set out by Ofgem as it has proposed to model at a licensee level.

BSCs are incurred at the DNO Group level, rather than the DNO level. This is an undisputable fact that Ofgem has explicitly recognised in DPCR5, RIIO-ED1 and was noted by its own consultants in GD2. This is because DNOs can benefit from scale economies by being part of larger DNO groups. We therefore fundamentally maintain that Ofgem should model BSC at a DNO group level recognising this relationship.

Modelling at the DNO Group level avoids cost allocation issues where BSC costs are shared across the Group based on potentially arbitrary cost allocation rules which are likely to be inconsistently applied. This unnecessarily introduces noise in the models and biasing the model outputs including the benchmark. These group-level scale effects should be captured in all relevant cost models, especially in the assessment of BSCs which suffers from cost misallocations. The evidence for this position is that the econometric model has poor statistical properties indicating that the modelling relationship between BSC and MEAV is incorrectly specified/ is under-developed, with the outcomes indicating there are material biases in the efficiency scores and allowed revenues of the DNOs.

We are therefore proposing two methods for accounting for group-level scale effects in the assessment of business support costs and improving the quality of modelling in this area. These are:

1. Including group-level scale variables in Ofgem's current BSC models. This maintains the structure of Ofgem's current analysis, but it does not account for the uncertainty created through cost allocation within a group.
2. Modelling BSCs at the group level, rather than the DNO level. This mitigates the issue of cost allocation, and also allows for the estimated coefficient on scale (e.g. MEAV) to represent all scale effects, rather than just DNO-level scale effects.

Not only are these two methods conceptually superior to that approach proposed at DD, but the BSC models perform materially better in terms of model fit and other statistical measures on this basis.

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

We note that Ofgem have used the 2019-2021 streetworks data submitted in BPDT tables M9a & M9b and scaled based on expected future workloads to identify ex-ante allowances for this category. This approach has two significant flaws;

1. The omission of table M9c in the BPDT template means that those streetworks costs recovered through the re-opener mechanism in RIIO-ED1 are not appropriately included in the baseline values used for the assessment. These are significant for ENWL due to the number of new permitting schemes implemented within the RIIO-ED1 period; and
2. The use of a historic average does not reflect the expected increasing take up of permitting schemes within our region which will see new charges levied in areas not included in the historic actuals.

It will be key to ensure that the costs of complying with new schemes are adequately compensated for within the Streetworks uncertainty mechanism for RIIO-ED2. In terms of correcting the baseline used for the analysis, we suggest that this could be corrected through use of the recently-submitted 2022 RRP data, or through a supplementary data request to DNOs for a combined M9b & M9c dataset.

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

We acknowledge that Ofgem want to ensure a level playing field when assessing company load submissions to allow consistent setting of baseline allowances and appropriate integration with the associated uncertainty mechanisms.

Our response to question 3 discusses the issues with the use of the ST ESO scenario and proposes an alternative approach. The response below is specific to the proposal as set out in the DD.

We agree with Ofgem that Totex model 3 explicitly includes a function relating to volumes of LCTs, however, Ofgem assumes that the cost impact of LCT connections is the same across all models. This is an inappropriate assumption: Totex model 3 is the only model that *directly* captures the impact of LCT connection growth, whilst the other two Totex models capture the impact of LCT connection growth *indirectly* (i.e. through correlations with other drivers, such as capacity released, peak demand and units distributed). Therefore, it is likely that the cost impact calculated in Totex model 3 will overestimate the cost impact of LCT connection growth in other models.

We consider that it is more appropriate to adjust the cost drivers included in the two other Totex models to reflect the alternative LCT forecast scenario. Specifically, we propose the following approach;

- Estimate the relationship between LCT connection growth and the affected variables (capacity released, peak demand and units distributed) using companies' forecast data.
- Using the relationship estimated above, adjust companies' forecasts for the affected variables to reflect the alternative forecast scenario.
- The adjusted cost drivers are then used to predict model-specific demand driven adjustments, following the same approach that Ofgem used to construct the demand driven adjustment in Totex model 3.

The table below shows the resulting model-specific demand driven adjustments compared to those published for ENWL in the DD.

Table 14: Model-specific demand driven adjustments results compared to those published in DDs

Demand driven adjustment	Ofgem adjustment (£m)	Oxera adjustment (£m)
Model 1	-49	-2
Model 2	-50	-30
Model 3	-50	-50
Disaggregated TOTEX	-4	-4
Triangulated adjustment	**-27**	**-16**

Note: Figures represent the total adjustment over RIIO-ED2.

Source: Oxera analysis.

As evidenced by the table 14 above, Ofgem's simplified smearing assumption overestimates the extent to which the models account for LCT connections growth.

We also disagree with the application of the adjustment across all cost categories. We propose it should be applied to the load categories and associated indirects only. This will ensure that the revised, post-adjustment disaggregated allowances are actually representative of the outcome modelled. We have included this in our alternative proposal for disaggregation of allowances as set out in our response to question 111.

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

We agree that either within-model accommodation of Quality of Service (QoS) or macro adjustments to efficiency analysis based on QoS are highly problematic and an issue that affects other regulated sectors as well.

Therefore, we agree with Ofgem that trying to take account of these within the models or on the cost outcomes from the ED2 models is not practical and we would expect Ofgem to apply their high evidential bar to any such claims on costs put forward by DNOs.

We would however, expect that incentives, incentive targets and outcomes (including levels of activity) be adjusted to reflect the efficient level of cost allowances as determined by Ofgem's cost assessment process. This is crucially important where:

- Regional variations aren't taken into account the calibration of QoS outputs/outcomes;
- Where the activity is bespoke with regard to its level of ambition or its nature; and/or
- The incentive is new for ED2 in application and design.

The failure to adjust outcomes to reflect cost allowances in the areas set out above risks leading to unfunded obligations, or levels of ambition that are unachievable where the costs have been benchmarked without consideration of the outputs/outcomes specified by the DNOs.

We note this is an issue which has been challenged successfully in the water sector at the CMA with reference to leakage targets and allowances and urge that Ofgem take heed of this service/ cost disconnect and make appropriate adjustments to outcomes/outputs to avoid this becoming an issue in ED. We consider this to be of particular importance when considering the targets for the three SDIs (Major Connections, DSO and Customer vulnerability) as well as the companies' Environmental Action Plans (EAPs) and commitments included within these at FBP stage, although it will not be limited solely to these areas.

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

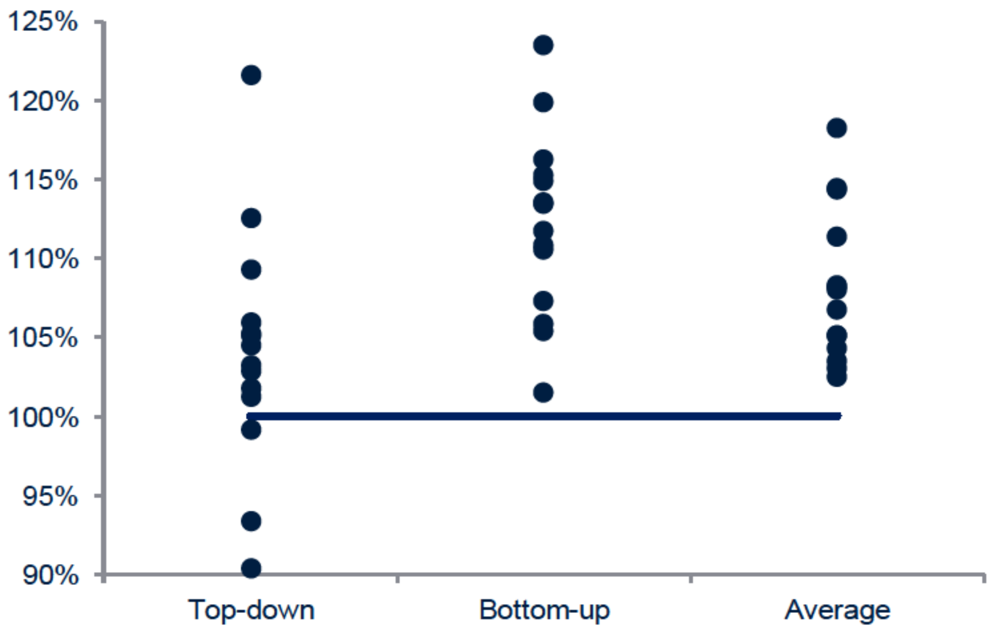
We agree that appropriately configured Totex and disaggregated approaches both provide insight into the assessment of efficient costs and that both have a role in the overall cost assessment framework. Whilst the choice of weightings is somewhat arbitrary, we agree that a 50/50 weighting of the two is consistent with the approach for RIIO-ED1 and we have not seen convincing evidence that this should fundamentally change.

Within the overall Totex area, our response to Q64 sets out the important considerations in the choice and specification of Totex models, including the requirement that they must offer competing and valid perspectives to each other. This being the case, an equal weighting of the three would appear appropriate.

However, Ofgem has not duly considered that, when combined with the overall challenge in the disaggregated models, the resulting cost allowances have not been achieved by a single DNO in the industry. That is, even excluding the possibility that there are biases and uncertainties in the assessment of individual DNOs, the benchmark is beyond the reach of any DNO despite the efficiencies embedded in their plans.

The figure below shows how DNOs perform in the Totex and disaggregated models, as well as their overall efficiency score.

Figure 9: Overall triangulated efficiency position



Note: Each point on the chart represents one DNO's performance. The top-down efficiency challenges have been adjusted to account for the glidepath to the 85th percentile.

Source: Oxera analysis of Ofgem (2022), 'CostAssessment_File.xlsx', June, sheet 'Cal_EfficientCosts'.

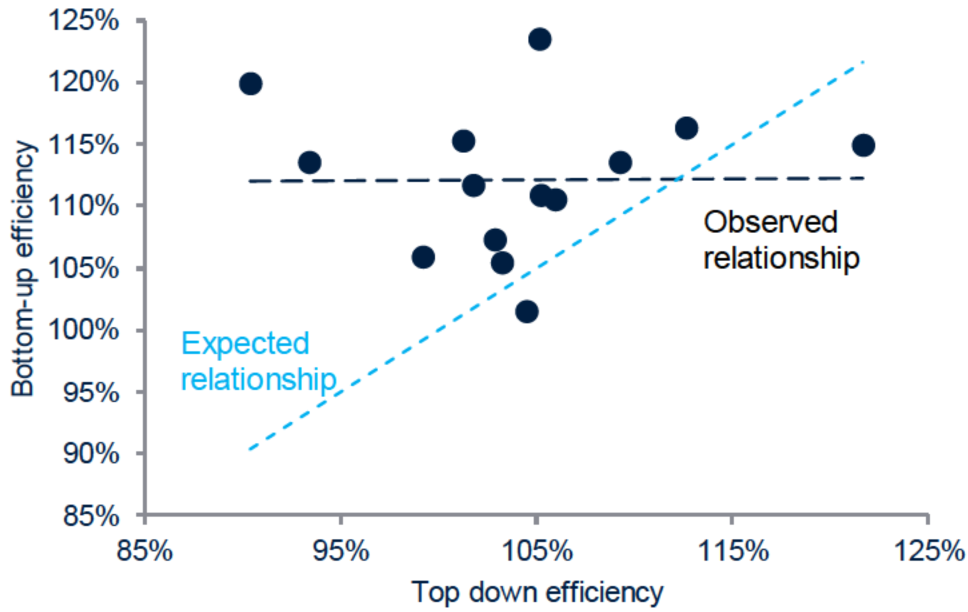
As the chart shows, no DNO is estimated to be efficient in the bottom-up models. Indeed, even when combined with the top-down modelling (where some companies are materially more efficient than the benchmark), not a single network is assessed to be efficient. By definition, the catch-up efficiency challenge represents the cost reduction that companies could achieve if they were to operate at best practice within the industry: if no company in the sample is operating at Ofgem's view of best practice, this challenge cannot represent a catch-up as the determination of the frontier is not justified. We are also unaware of any regulatory precedent that would justify all companies being inefficient in a national benchmarking exercise as a result of the catch-up analysis (i.e. before other efficiency challenges and adjustments are applied).[34]

[34] At ED1, Ofgem used a combination of TOTEX models and disaggregated analysis to set allowances. The correlation between a DNO's performance in the TOTEX models and its performance in the disaggregated analysis was c. 0.5. While this is not a very strong correlation, it is clearly positive. However, the correlation at ED2 is c. 0.01, which is statistically indifferent from zero, indicating no relationship.

This can be partly explained by the way in which Ofgem has estimated its disaggregated models. However, another consideration is that there appears to be little relationship between a DNO's performance in the Totex models and the disaggregated models. While some deviation in performance is expected due to the different cost drivers and modelling assumptions made, one would expect there to be some correlation in a DNO's performance between the different types of models. Indeed, the definition of robustness applied in several jurisdictions relates to the corroboration of results under different modelling assumptions.

The chart below shows the relationship between a DNO's performance in the Totex and disaggregated modelling, compared to the 'expected' relationship.

Figure 10: Relationship between bottom-up and top-down performances



Note: Each point on the chart represents one DNO's performance.

Source: Oxera analysis of Ofgem (2022), 'CostAssessment_File.xlsx', June, sheet 'Cal_EfficientCosts'.

As the chart shows, there is no real correlation between a DNO's performance across the type suites of models. Indeed, the most efficient company according to the Totex models (leftmost point on the chart) is the second least efficient company in the disaggregated models. Similarly, the most efficient company in the disaggregated models (lowest point on the chart) is an average performer in the Totex models (specifically ranked 8 out of 14). This issue is demonstrated in the figure below.

Figure 11: Ranking across different model suites

	Top-down	Bottom-up	Difference
ENWL	12	8	4
NPGN	10	6	4
NPGY	7	2	5
WMID	11	5	6
EMID	4	11	-7
SWALES	6	4	2
SWEST	14	10	4
LPN	1	13	-12
SPN	2	9	-7
EPN	5	7	-2
SPD	3	3	0
SPMW	8	1	7
SSEH	9	14	-5
SSES	13	12	1

Source: Oxera analysis of Ofgem (2022), 'CostAssessment_File.xlsx', June, sheet 'Cal_EfficientCosts'.

The table above shows that the significant differences in performance across the suite of models are not limited to SPMW and LPN. Indeed, 10 of the 14 DNOs' rankings change by four or more between the two suites of models. The significant uncertainty regarding a DNO's true level of efficiency warrants a more cautious, evidence-based approach to setting the benchmark and overall Totex allowances. Indeed, given the significant volatility in DNO performance across modelling approaches, a more reasonable approach would be to give DNOs the 'benefit of the doubt', whereby a DNO's allowance is determined by the model suites where it performs best. In this way, the intrinsic biases and uncertainties in Ofgem's cost assessment could be mitigated to some extent.

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 strongly disagree with the application of an 85th percentile catch-up efficiency benchmark and set out that applying this more stringent benchmark when compared to ED1 is not supported by the modelling undertaken by Ofgem for ED2.

We have commissioned Oxera[35] to independently consider this issue and the findings of this report should be read and considered alongside our response to this question.

The application of the 85th percentile to lower quality models than ED1 when combined with issues related to the disaggregated modelling suite[36] sets an efficiency challenge which is beyond the efficiency frontier. This is unprecedented as, since privatisation, economic regulators and the appellate courts, including the CMA, have never set the benchmark at the frontier accepting that no analysis, whether econometric or otherwise can provide precise point estimates on where the frontier position is. Consideration of 'margin of error' is key as the actual benchmark may be more stringent in practice than an analytical model may suggest due to simplification of reality, modelling errors and data limitations. When Ofgem combines the disaggregated and Totex modelling approaches it has failed to give due consideration to the margin of error with the effective benchmark being set beyond the frontier.

With specific regard to the Totex models for ED2 these perform particularly poorly on several key statistical diagnostics, including model fit and the RESET test. Model quality is a crucial consideration when the benchmark is calibrated as more stringent benchmarks should only be applied to models

[35] Oxera (2022), 'Review of Ofgem's proposed efficiency challenges', August, Appendix 2
[36] We set out our response to the disaggregated approach in more detail in the questions of this document from 64 to 94, 96 to 102, 107 and 111.

where the quality is increasing or stronger than those previously developed. This is highlighted when compared to ED1 where a lower UQ benchmark was applied and GD2 where Ofgem applied a similar glidepath to the 85th percentile. Therefore, use of 85th percentile in ED2 can't be supported because:

- The models are poorer than those where a UQ was applied in ED1, and
- Poorer than those where 85th percentile was applied in RIIO-2.

Ofgem has acknowledged this through response to one of our SQs[37] where it sets out it has conducted analysis that suggests that the Totex models predict companies' expenditure with a higher degree of uncertainty at ED2 than at ED1.

Further to this it would seem that Ofgem has failed to take note of cost assessment working group (CAWG) discussions and the articulation in slides/ discussion led by Northern Powergrid (NPg). This set out well in advance of the DD that Ofgem should not apply the same approach from GD2 into ED2 without considerations of the different circumstances of ED2. We are not aware of any consideration/justification being set out in the DD or elsewhere.

For these reasons, the proposal of Ofgem to increase the stringency of the benchmark is unsupported by the evidence and we recommend Ofgem reconsider this material aspect of its DD applying a benchmark lower than the 85th percentile with glidepath from the 75th percentile it currently proposes to use. In this context we would note that the impact of moving from a glidepath to a UQ benchmark is material affecting cost allowances by c.0.7–0.8 percent.

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 are party to the ENA commissioned work through NERA[38] and are supportive of the conclusions of that report, though we welcome the Ofgem DD position that upfront allowances for RPEs will be provided and agree this is correct to 'true-up' after the indices/indexation impact is known.

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

We strongly disagree with both the approach to ongoing efficiency, as well as the level of challenge that has been applied.

In considering our response to this question we have reviewed the justification which Ofgem has presented in its DD as well as the methodological report by its provider CEPA[39]. In addition to our own internal review, we have also commissioned Oxera[40] to independently review and assess the same evidence provided in the DDs. We are also further party to the ENA collaborative work commissioned in this area through NERA[41] and Frontier[42] and we are supportive of the conclusions reached in all these reports[43].

It is our view that the Ofgem justification for setting the OE target of 1.2% p.a. at the highest number (effectively aiming up) is wrong. The arguments are internally inconsistent, unsupported by robust evidence and results in a double count. For example, the transformational change expected in ED2

[37] Supplementary Question: ENWL023.
[38] NERA (2022), 'Response to RIIO-ED2 Draft Determination on Real Price Effects' for ENA, August.
[39] CEPA (2022), 'RIIO-ED2: Cost Assessment – Frontier Shift methodology paper', June.
[40] Oxera (2022), 'Review of Ofgem's proposed efficiency challenges', August, Appendix 2
[41] NERA (2022), 'Response to RIIO-ED2 Draft Determination on Ongoing Efficiency' for ENA, August.
[42] Frontier (2022), 'RIIO-ED2 Productivity Target' for ENA, August.
[43] Oxera, NERA and Frontier.

requires more expenditure rather than less, and any perceived incremental efficiencies resulting from increased activity levels are already captured in Ofgem's comparative assessment in determining the cost allowances.

Additionally, Ofgem's justification based on embodied technical change for ED2 is no different to recent regulatory decisions that have used embodied technical change to justify a target beyond what is estimated by a robust application of the growth accounting methodology. Where this has previously been estimated by a regulator it was found to be 'inconsequential'[44]. It is therefore incorrect for Ofgem to assert embodied technical change to justify an unprecedentedly large OE target without empirical analysis to evidence quantifiably any potential for an adjustment.

Further the justification of Ofgem also creates perverse incentives for companies to the long-term detriment of consumers. For example, Ofgem argues that the 1% p.a. target put forward by the most ambitious companies, including ourselves, is likely to underestimate what is actually achievable due to information asymmetries. However, setting companies' submissions as some lower bound, either implicitly or explicitly, can encourage companies to submit less ambitious plans in future price reviews, which can result in a long-term detriment to consumers. Moreover, most companies relied on the same EU KLEMS dataset and regulatory precedent that is publicly available in informing their OE assumption.

Further, we have also concluded that the methodological approach undertaken by Ofgem is also wrong and incorrectly applied. This position is split out into two broad areas;

1. The method by which the 1.2% p.a. challenge has been derived including the evidence which it is justified on.
2. How this is applied, with specific reference to its application to the last two years of ED1.

We set out the high-level issues to each in turn below, but stress it is critical that Ofgem review the evidence base in full including the Oxera paper, as well as the papers from NERA and Frontier, when considering our response to this question.

1. <u>The method by which the 1.2% p.a. challenge has been derived including the evidence which it is justified on.</u>

It is our conclusion based on the evidence we have reviewed and commissioned that Ofgem's proposed target of 1.2% per annum is based on a selective use of the evidence produced by its providers that is only supported by unjustified assumptions that renders a material upward bias in the OE target for ED2. Ultimately the OE challenge of 1.2% p.a. is only supported by one specific point estimate out of 48 estimates assessed with 1.2% the highest of all the estimates set out.

When considering the specifics of the method used to derive 1.2% p.a. the OE target is based on:

a) VA measure of TFP,
b) Estimated over incomplete business cycles, and
c) The use of the 'expanded' comparator set and its weightings.

We contend that all these are incorrectly used and they individually and collectively biases the OE target upwards. We set out the summary arguments in for each below:

[44] Economic Insights (2020), 'Frontier Shift for Dutch Gas and Electricity TSOs', May, p. 76.

1a) Use of VA measure of TFP

It is our conclusion that the use of VA measure of TFP is wrong. Indeed, whilst Ofgem and CEPA have considered GO, 1.2% is only supported by the use of VA measure of TFP.

The key distinction between VA and GO measures of productivity growth is that VA measures do not account for the contributions of intermediate inputs[45] and is focused exclusively on labour and capital.

Intermediate inputs account for a substantial portion of our, and other DNOs, which means the use of a VA measure of TFP is relevant for only **part** of the cost base (e.g. labour costs or capital spending), but it is **not applicable** to the total cost base (Totex). As OE is applied by Ofgem to Totex (without relevant adjustment) the use of VA measure of TFP is incorrect as Totex includes substantial expenditure on intermediate inputs which are not accounted for when estimating the VA measure of TFP.

When adjustments are derived for to the VA-based measures of TFP using the same EU KLEMS dataset,[46] the resulting OE targets are between 0.1% p.a. and 0.4% p.a. (keeping all else the same), which is materially below the 1.2% p.a. figure.

1b) Estimation over incomplete business cycles

Productivity growth should be estimated over complete business cycles, and that an assessment over incomplete business cycles can lead to biased estimates of TFP growth. This is acknowledged by Ofwat,[47] Ofgem,[48] CEPA[49] and the Competition and Markets Authority (CMA)[50] where their views all are similar in the need to estimate productivity growth over complete business cycles.

The proposal therefore to model over incomplete business cycles renders a material bias in the estimated OE target with the highest target supported by CEPA's analysis over complete business cycles is 0.9–1% p.a. (lower than the 1.2% applied) with these figures relying on the inappropriate measure of productivity growth (i.e. VA) and an inappropriate comparator set.

1c) The use of the 'expanded' comparator set and its weightings

The OE challenge of 1.2% is only supported by the use of the 'expanded' comparator set. This comparator set includes two additional sectors: 'Professional, Scientific, Technical, Administrative and Support Service Activities' and 'IT and Communication'.

We consider the use of IT and communications to be incorrect as it is set out that this is to account for the impact of digitisation on the scope for productivity improvements. As the impact of digitalisation will be realised through productivity improvement achieved in the other comparator sectors as IT and communication services have been a driver for the other sectors as well. Therefore, the impact of digitalisation would be captured by the core comparator sectors, which would be more relevant and

[45] Intermediate inputs are inputs that are consumed in the production process, such as materials, energy, and services procured from external organisations.
[46] Specifically, we apply the VA share of GO in the 'Electricity, gas, steam and air conditioning supply' sector to the VA TFP estimates from the comparator sectors. An alternative approach to deriving an adjusted VA could be to explore the share of intermediate inputs in TOTEX for the electricity DNOs.
[47] Europe Economics (2019), 'Real Price Effects and Frontier Shift – Updated Assessment', July, section 3.8.
[48] See, for example, CMA (2021), 'Final determination Volume 2B: Joined Grounds B, C and D', October, para. 7.36 and para. 7.38.
[49] See, for example, CEPA (2020), 'RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper', May, p. 11.
[50] See, for example, CMA (2020), 'Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations Final report', March, para. 4.533

tangible for the DNOs. The narrow yet specific comparator set is a better approximation of a robust approach to comparator selection and weighting and focusing on this comparator set reduces the OE target from 1.2% p.a. to 0.8% p.a. (keeping all else the same).

To compound the issue, Ofgem has used an unweighted assumption on each of its comparator sectors. This therefore means sectors with lower or no direct comparison to DNOs activities and costs have the OE observed from these applied on the same weighting as more relevant sectors. Weighting of the comparator sectors must be applied to ensure that the OE target calculated is reflective of the activities mix undertaken by DNOs.

2. <u>How this is applied, with specific reference to its application to the last 2 years of ED1.</u>

As well as the methodological flaws in assessing and setting a 1.2% p.a. target, the application of the OE target to modelled Totex results in a more stringent cost reduction target than the headline figure of 1.2% p.a. To do this Ofgem has incorrectly applied the OE target to modelled efficient Totex for the two years before the start of ED2 (e.g. the last two years of ED1) to derive its view of efficient costs in ED2. As the 1.2% p.a. target is compounded over six years, starting in 2022 this leads to an overall ongoing efficiency challenge of c. 5.8% over the ED2 period.[51]

This is incorrect as because forecast data for the final two years of ED1 (2022 and 2023) is incorporated into the Totex models the OE that companies are expecting to achieve over this period is already accounted for in companies' business plan data as well as by extension the cost assessment models. Therefore, applying the OE challenge over these two years leads to a double-count of the overall scope for productivity improvements.

In order to remove the double-count, it would be appropriate to begin the compounding year in 2024 instead of 2022, in line with regulatory precedent.[52] This reduces the overall challenge from c. 5.8% to c. 3.5%.[53]

<u>Summary</u>

It is our view therefore that Ofgem must review and take careful consideration of the evidence we have provided in this response including; the Oxera report for ENWL and the NERA/ Frontier reports provided for ENA on behalf of its members.

Based on this evidence Ofgem should:

- Only apply its OE challenge to the period of ED2 and not the last 2 years of ED1 as it currently does.
- Set an OE challenge materially lower than the 1.2% p.a. calibrating it to a level supported by a representative and justifiable use of the supporting data and in consideration of regulatory precedent rather than the selective use/interpretation of the evidence which it has used in its DD.

[51] The OE challenge gradually increases from c. 3.6% p.a. in 2024 to c. 8.1% in 2028, which equates to an average cost reduction target of c. 5.8% over the period.

[52] See, for example, Competition and Markets Authority (2021), 'Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations: Final report', March, para. 4.643.

[53] Under the correct application, the cost reduction target increases from 1.2% in 2024 to c. 5.9% in 2028, which equates to an average of c. 3.5% over the period.

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

Absolutely not. The DD generated an adjusted inflated view of our submission which was substantially benchmarked down in quantum, and that quantum used to pro-rate allowances across categories. This process severed any link between what Ofgem say they have concluded on a specific area in the published DD documents and the outcomes of the cost assessment process itself.

As examples of the consequences, our data & digitalisation proposals are not actually funded; neither is our Bespoke ODI-R on Borrowdale transformers, nor our accepted NARMs output or our approved ESR costs. Conversely, our load baseline is significantly higher than in our baseline request, despite Ofgem using a more conservative Net Zero scenario in their assessment.

For the FD, Ofgem need to implement an approach which represents the actual assessment of individual cost areas and hence needs to be rooted in a (corrected) disaggregated modelling analysis, scaled to reflect the Totex outcome and any post-modelling adjustments.

This will allow the setting of appropriate and specific baselines where required for the purposes of the ED2 licence.

We have shared illustrations of how this could work with the Ofgem team and have followed up with a proposal to the Cost Assessment Working Group. We look forward to working with Ofgem to implement a more sensible approach in this area for FD.