Sector Specific Methodology Consultation response

Annex 1: Overview

September 2020

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1 Stakeholder Engagement

Our RIIO-ED2 engagement has been ongoing with stakeholders and customers for a considerable time now, the output of which continues to shape our thoughts and business plan development as we gain deeper and richer insights into the role of electricity in our customers' lives and better understand our stakeholders' priorities as we continue the energy system transition.

In the past weeks we have also engaged specifically on this RIIO-ED2 methodology consultation, to directly flag the Ofgem consultation, met with our independently chaired stakeholder panels, and also held a series of regional stakeholder workshops in our three main geographical areas of Greater Manchester, Lancashire and Cumbria. The insights gained through this recent engagement have helped shape our response and have been included in our responses within this Overview document, along with the other annexes on Keeping Bills Low and Value for Money services.

We also publish our responses provided to Ofgem on our website.

2 The RIIO-ED2 process

Q1 Do you have any views on our proposal to include a statement of policy in Final Determinations that in appropriate circumstances, we will carry out a post appeals review and potentially revisit wider aspects of RIIO-2 in the event of a successful appeal to the CMA that had material knock on consequences for the price control settlement?

We have responded to this question as part of our submission to the GD/T Draft Determinations (DDs) as we consider this a principle issue that extends wider than each individual price control. Ofgem is undermining the established process of the CMA.

We understand that Ofgem's position is that "in appropriate circumstances, we will consider whether to review wider aspects of the price control settlement following the conclusion of a successful appeal to the CMA. The aim of such a review would be to ensure a coherent regulatory settlement is maintained in the event the CMA's decision has material knock on consequences for the wider price control settlement."[1]

Ofgem gives two examples of where it envisages a post appeals review may be carried out. These are:

- "The CMA quashes the decision(s) appealed and remits to Ofgem for reconsideration with a direction that Ofgem reconsider the decision and consider interlinkages; or
- The CMA quashes the decision(s) appealed, retakes the decision itself but directs Ofgem to consider interlinkages."[2]

Ofgem suggests this is not an exhaustive list, as it is difficult to set out possible future scenarios. The key issue from our perspective is whether Ofgem is intending to leave open the possibility of post appeals reviews in circumstances where it has not been specifically directed to (re)consider a matter by the CMA.

[1] Draft Determinations: Core document, table below paragraph 11.30, Ofgem
[2] Draft Determinations: Core document, paragraph 11.32, Ofgem

If Ofgem is clarifying that it will do as directed, then we do not consider that any policy statement needs to be made. A policy statement setting out that Ofgem would comply with the binding directions of the CMA is otiose.

If Ofgem is intending to leave open the possibility of further post appeals reviews, Ofgem should be explicit about its intentions, to allow parties to engage meaningfully. That said, if this is Ofgem's intention, the comments provided by ENWL in its March 2019 response to Ofgem's Cross-sector questions would continue to apply. We elaborate on those points below, similarly to our DD response for GD/T2.

- The appeals regime is not there to safeguard a 'settlement in the round'. Its purpose is to allow licensees to seek redress where Ofgem has made errors so as to allow for necessary corrections to be made. This is consistent with the EU Third Energy Package requirements that Member States "ensure that suitable mechanisms exist at a national level under which a party affected by a decision of a regulatory authority has a suitable right of appeal to a body independent of the parties involved and of government."
- The CMA's powers in determining price control appeals are broad and include quashing the decision, remitting the decision back to the authority for reconsideration and determination in accordance with any directions and substituting its own decision for that of the authority and making any such directions as are necessary. The CMA is able to consider interlinkages in the appeals process. It is therefore for the CMA to determine whether consequential amendments are required to the price control decision when correcting the error(s) and not for Ofgem, which must act in accordance with the CMA's determination including any directions.
- In circumstances where, further to a decision on appeal by the CMA, Ofgem reopened and reconsidered an aspect that it was not directed to by the CMA, it is highly likely that the parties subject to any further changes would appeal this decision. It cannot be in anyone's interests – least of all consumers – for repeated adjustments to be made to price control settlements. Ofgem would also, in that scenario, need to be aware of the deleterious effect on regulatory certainty, which would increase the risk associated with investing in regulated companies (and so increase licensees' cost of equity).

In practical terms, the perceived threat (that matters will be reopened after an appeal) will mean that the consideration of interlinkages in any appeal process will be vital. Ofgem will need to set these interlinkages out at an appropriate point in the process. This process rightly begins with the regulator explaining interlinkages in its considerations and especially any decisions. Ofgem should not seek to reserve to itself the possibility of considering interlinkages other than those raised in its decision or considered in the appeals process. The threat to coherence of a regulatory settlement would only arise if Ofgem does not properly document relevant interlinkages and/or fails to raise them in an appeals processes.

Q2 Do you have any views on the proposed pre-action correspondence, including on the proposed timing for sending such to Ofgem?

We have responded to this question as part of our submission to the DDs. For ease of reference we have provided the same response in this sector methodology consultation below.

Ofgem's position is that it "expect[s] any prospective appellant to send pre-action correspondence at a sufficiently early stage after the publication of Final Determinations and ahead of the deadline for making an application for permission to appeal."[3] Ofgem makes reference to the view of the CMA, which we consider is a helpful starting point. The CMA stated:

> "We wish to encourage this pre-appeal conduct [of early, active engagement] as good practice. Where it appears that appellants have acted in a way which, without good reason, makes case management more difficult, for example appellants who fail to engage with the appropriate regulators and notify us and update us about their potential intentions to appeal, this could be reflected in our assessment of their conduct when allocating costs at the end of the appeal, even when such appeals are successful. Ideally, we would prefer such pre-notification to include the potential scope of any appeal, rather than be limited to notification of the potential existence of an appeal."[4]

While we appreciate that early and positive engagement with the regulator about appeals is a practice to be encouraged, we would be surprised if Ofgem was unaware of the likely grounds of dispute given the degree of engagement during the price control process. Moreover, there are practical reasons why it may be difficult or inappropriate to engage early. In particular, Ofgem will appreciate that deciding to bring an appeal to the CMA is often a finely-balanced decision and companies will want to see the final outcome of the price control process before deciding whether to appeal or not. Ofgem's position, that such pre-action correspondence is "expected" is not clear as to the legal effect envisaged, and it would be helpful if Ofgem clarified its position.

To the extent Ofgem is seeking to make pre-action correspondence compulsory, we would note that the process for appeals to the CMA is well-established, and laid down in legislation, supplemented by the CMA's rules on energy licence modification appeals (CMA70). Companies should adhere to the requirements of the appeal process. This process has been designed to be fair and workable to both appellants and the regulator. Prospective appellants can decide what, if any, further information they share with Ofgem beyond that which is legally required. It is not for Ofgem to add to or amend the CMA's rules or the statutory process.

To the extent Ofgem is seeking to position the lack of pre-action correspondence as a matter that the CMA should take account of in allocating costs at the end of an appeal, we would note that this too is a matter for the CMA. It cannot be for one party to an appeal to determine the terms on which costs are allocated between parties. In contrast, the CMA's view appears not to place an "expectation" of pre-action correspondence on appellants.

It follows from the above that we have nothing to add on the proposed timing for "encouraged", voluntary pre-action correspondence.

3 Net Zero and Innovation

Q3 Do you agree with our proposed approach to a Net Zero re-opener?

Our view is consistent with our response to the Net Zero Open Letter in May 2020, extracts of which are shared below. We would add that, in the interest of transparency, it would be helpful if Ofgem published the Open Letter and the responses received (subject to respondent agreement) so that

[3] Draft Determinations: Core document, table below paragraph 11.30, Ofgem
[4] CMA Response: Clarification of our position on potential Energy Licence Modification Appeals, paragraph 12, CMA

stakeholders can see respondent views and how this input has shaped Ofgem's thinking. We support transparency ourselves and have published our response on our website[5].

We note the many references to the Net Zero Advisory Board both with reference to the Net Zero re-opener and also the Strategic Innovation Fund (SIF). It would be helpful for Ofgem to provide more information on the composition and work schedule for this group as there is limited information available at present and therefore it is unclear how this will be used to inform any decision by Ofgem to trigger the Net Zero re-opener.

We also recognise that Electricity Distribution (ED) has the benefit of time (i.e. Final Determinations in 2022) where policy and pathways may be clearer compared to Gas Distribution or Transmission which are to be settled much earlier. We therefore consider that this re-opener proposal is possibly more needed and has greater likelihood of being triggered for the earlier RIIO-2 price controls than for RIIO-ED2.

Scope

We support the use of a limited number of targeted re-opener/uncertainty mechanisms that are well defined and are clear as to what risk or uncertainty they are to address in the period. We do however recognise that they can also reduce the responsiveness of the sector to changing customer and stakeholder needs. The use of automatic mechanisms such as volume drivers and provision of sufficient upfront allowances that can be mechanically modified will best serve customers in this rapidly changing environment. This approach, with an enabling baseline and well-designed volume drivers, will serve Ofgem well in its discussions with government to demonstrate how Ofgem is enabling Net Zero.

We therefore do not believe the proposed broad scope of the Net Zero re-opener meets our criteria and therefore our position is that it should be reconsidered.

The proposed broadness of the mechanism may lead to a lack of clarity for all stakeholders including companies and Ofgem about how and why it should be applied and assessed. In our response in May 2020 we cautioned against setting any Net Zero mechanism with insufficiently defined parameters; these should be tightly set, targeted and linked only to those driven by change in government policy (either central or devolved), unforeseen breakthroughs in technology driving changes in consumer requirements or significant market driven changes leading to unforeseen lower low carbon technology costs.

The wording in the consultation position of "changes connected to the achievement of the Net Zero carbon targets not otherwise captured by any other RIIO-ED2 mechanism"[6], combined with the proposal that the re-opener can be used by Ofgem at any time in the price control brings a significant degree of uncertainty and risk to companies that changes to outputs and allowances can be made at any point in time for a variety of unknown reasons.

Our recommendation is that the proposed scope be tightened in line with our suggestion above.

Process

Whilst it is pleasing to see the recognition that licensees can provide valuable input to ensure the mechanism can work effectively, it is still unclear within the consultation document what timescales are anticipated for the duration of the process described.

[5] https://www.enwl.co.uk/about-us/regulatory-information/riio2/

[6] RIIO-ED2 Methodology Consultation: Overview, table 3 below paragraph 4.13, Ofgem

As with the other re-openers or uncertainty mechanisms described within the consultation, the most critical process consideration for the Net Zero re-opener is that Ofgem will need to be able to make material decisions much more rapidly than today's processes and based, relatively speaking, on incomplete information compared to Ofgem's normal requirements for a complete and high standard of evidence. This will enable companies to react quickly to an emerging Net Zero need.

Ofgem is clear that it considers a lower returns and lower risk price control to be the aim for RIIO-2, hence any Net Zero re-opener will be reserved for actions that a company will not be able to commit to absent of regulatory agreement, as to do so would be higher risk. During RIIO-2 it looks likely that companies will have less financial flexibility to respond quickly to emergent needs ahead of Ofgem providing funding, therefore cashflow considerations will be more important in RIIO-2 and could result in shovel ready projects needing to wait for revenue to start being collected. In distribution, this could mean a two year pause until revenues can be set to fund the cash costs of investments. Supply chains would then need to be activated and then commence delivery, likely taking further time. It is therefore critical that any Net Zero re-opener process can be decided quickly and that there is timely, positive impact on the cash position of the company if further expenditure is required.

The target should be for Ofgem to make any decision and enable the company to appropriately adjust its revenues to meet any new cash expenditure needs within three months of the start of the process. These kinds of timescales might be what are needed to avoid regulation becoming a blocker to meeting customer needs. Ofgem may want to also consider whether an approach where some initial funding could be rapidly released on a no-regrets/no-hindsight risk basis to allow companies to mobilise to meet urgent customer and stakeholder needs with a short lead time, if Ofgem needs more time to make any decision(s).

<u>Materiality</u>
In setting the materiality threshold and how the re-opener might work, the RIIO-2 package in the round needs to be reviewed and Ofgem's common approach to materiality should not necessarily be adopted by default. In a lower return price control with potential for more reliance on uncertainty mechanisms or specific PCDs there is naturally much less flexibility for companies to respond as they have in RIIO-1 to changing environments. Rapid decision making by Ofgem to determine allowances and direct that companies can immediately update their tariffs to fund the obligations agreed will facilitate the responsiveness required.

<u>Interlinkages</u>
How any Return Adjustment Mechanisms (RAMs) are implemented is also key. Any re-opener funding for Net Zero would need to be adjusted for in how any RAM works.

We strongly suggest that a detailed assessment of the interlinkages between different re-openers in place be carried out and shared and consulted on with companies and stakeholders.

Q4 In what circumstances, would a centralised approach to setting forecasted outputs be appropriate? What form should this take?

We firmly believe that our customers do not benefit from centralised approaches in the forecasts used for network planning. Using national policies and information in a decentralised approach is different from a centralised approach. The RIIO-ED2 submission should not be an exception to this.

Specifically in the case of network planning, innovation projects such as our ATLAS NIA project and the business-as-usual processes of all DNOs to deliver their Distribution Future Electricity Scenarios (DFES) have demonstrated the value of decentralised approaches and in particular the need to consider bottom-up and half-hourly through year (seasonal time-series) modelling in forecasts to be able to frame regional uncertainties in network planning. The bottom-up modelling approaches consider national policies and national information but, importantly, they also consider how these will act upon the regional realities that are critical to produce meaningful regional trends. Bottom-up modelling is, by definition, a decentralised approach and therefore using a centralised or top-down approach is expected to neglect regional characteristics and be less precise.

Following a centralised approach is expected to result in using non-representative forecasting trends in regional network impact analysis. Therefore, under no circumstances could a centralised approach be preferable for distribution network planning. It should be again highlighted that using national policies and national information within a decentralised approach is different from a centralised approach. Centralised forecasts could lead to network issues being identified in the wrong place, other network issues being missed, and investments being planned in inappropriate places and times.

As an industry, all DNOs, with collaboration from the ESO, have worked closely in the ENA Open Networks[7] project to standardise the way that DNOs produce their regional forecast that have a primary focus on network planning in Workstream 1B, products 2 and 5. A decentralised forecasting approach that brings further standardisation across all DNOs has been found the most appropriate approach to capture regional uncertainties in distribution network planning. We have received positive feedback from Ofgem not only on our agreed decentralised forecasting approach in Open Networks ("initial alignment & feedback model"), but also in our ATLAS decentralised forecasting approach that has been used in our two DFES publications as well as helping most DNOs and the ESO to understand the benefits of bottom-up modelling prior to the Open Networks work.

Therefore it comes as a surprise to see Ofgem, who has previously supported decentralised approaches in our DFES, our ATLAS project work, and the common Open Networks work with all DNOs, now considering a centralised forecasting approach for the RIIO-ED2 submission. We recognise Ofgem wants to secure views on a range of options as part of consulting and we look forward to seeing the published responses. Depending on Ofgem's conclusions, there could be material impacts on the Open Networks activities in which Ofgem has been participating, which may need to change strategic direction, so earliest feedback from Ofgem is highly desirable.

There are several examples that will help highlight that centralised approaches can result in regional trends that are not representative of the regional realities. Key examples showing the inadequacy of centralised approaches for network planning are:

- **For domestic demand and heat-pump uptakes:** Centralised approaches do not consider the existing building stock (e.g. under each primary substation feeding area) and the regional potential to improve heating efficiencies due to the mix of premises under each region and/or the regional likelihood due to this mix to change their heating fuel type to electricity. Importantly for heat pumps, factors such as the access of customers to the local gas networks cannot be used in consumer choice modelling to reflect the importance of this factor to forecast regional volumes of heat pumps. This could lead to over/under-estimated demand growth and thus result in a RIIO-ED2 programme that contains a mix of under-utilised assets and/or under-reinforcement in different parts of the network.

- **For flexibility modelling (i.e. DSR, smart meters, smart EV charging etc. in general all non-DNO triggered flexibility):** Only decentralised approaches can use the local half-hourly loading data (e.g. per primary substation) to show how demand could be shifted

[7] https://www.energynetworks.org/electricity/futures/open-networks-project/

at local level and then aggregate the effects at higher voltage levels via half-hourly through year modelling. Any centralised alternative to the decentralised approach could lead to over/under-estimated demand growth and thus result in a RIIO-ED2 programme that contains a mix of under-utilised assets and under-reinforcement in different parts of the network.

- **For planned developments of local stakeholders where DNOs have received quotation requests:** This is information that DNOs gather via their direct engagement with local stakeholders (i.e. customers, Local Authorities and Local Enterprise Partnerships). Only decentralised approaches can provide confidence factors for the amount of quoted and accepted demand and generation projects per region that are expected to be energised, as well as their expected performance based on both historical performance from large sampling and per project information from direct DNO engagement with local stakeholders during the connection process. Planned developments via half-hourly through year modelling that considers the local half-hourly through year network loading can show the effects across all voltage levels in a bottom-up modelling approach. Any top-down/centralised approach could over/under-estimate demand or generation growth, both due to neglecting volumes/profiles of likely developments, and thus result in a RIIO-ED2 programme that contains a mix of under-utilised assets and under-reinforcement in different parts of the network.

- **For large scale projects that are at an early stage (connection quotes not yet received by DNOs):** Such projects can be planned developments of wide areas. We would consider these projects only in cases where adequate information through studies and technical analysis can be provided. For example, for a large domestic and commercial development we would not assume that all buildings will be directly populated, and all domestic customers would adopt EVs and heat pumps. We would consider only the Local Authority /customer plans that have well justified assumptions in the year by year demand growth, including information such as:

    - The socio-economics of the area and the affordability of domestic and commercial customers to justify the LCT uptake trends;
    - The assumptions on the diversification of demand of individual customers (in line with national or international standards);
    - The types of loads for commercial/industrial customers and the consideration of the half-hourly profiles of these loads on the demand growth.

  Any centralised/top-down approach would neglect the effects of such developments on regional demand trends. All this information needs to be used in decentralised forecasting that has bottom up and half-hourly through year modelling in its core to properly understand how the demand growth from these projects interacts with the underlying loading and the other demand uptakes, for example from LCTs. Any centralised approach cannot capture this and could result in neglecting targeted interventions at minimum cost and risk to support mature local stakeholder plans taking into account the wider regional challenges to the electrification of transport and heating.

- **For EV charging:** Regional access of customers to off-street parking and the regional potential for other types of charging (i.e. rapid charging in areas with critical traffic flows and destination charging taking into account regional behaviour of work and shopping commuters) can determine the effects of EV charging per region. Additionally, a centralised allocation of EVs that neglects the regional socio-economics can result in forecasts of much higher/lower volumes of EVs in particular areas. Therefore, centralised approaches in forecasting can result in an RIIO-ED2 programme that considers overspending or cannot facilitate the EV charging by missing the intervention requirements from the LV up to the grid and primary network.

- **For distributed generation and battery storage:** Only decentralised approaches can consider critical regional factors such as the interaction of DNO planning with customer decisions (e.g. available network capacity per BSP substation), as well as the regional land and domestic/commercial roof availability for renewable generation (PV and wind generation mainly). Also, any centralised approach is going to neglect the plans of existing generation customers to use their existing connection agreements to change their business models (e.g. from CHP generation to battery storage installations at EHV or HV networks).

Q5 What would be the factors we should take into account that would give us high certainty in a centralised approach to setting outputs?

See our response to Q4 which covers a joint response to Q4, Q5, Q6 and Q7. We cannot see any circumstances where a centralised approach would bring high certainty in appropriately setting outputs and allowances to meet essentially regional needs from different regional starting points. A centralised approach also runs significantly counter to the devolved approach to government and Ofgem's enhanced engagement approach which has effectively stimulated even greater regional input and insight to Business Plans. Finally, a centralised approach risks becoming a blocker to regional needs where outputs are underset and extra cost to consumers that needn't have occurred in other regions if outputs are too advanced.

Q6 Alternatively, in what circumstances would it be more appropriate to take a decentralised approach to determining forecasts?

See our response to Q4 which covers a joint response to Q4, Q5, Q6 and Q7. A decentralised approach but using a common framework as developed through Open Networks, is our strong recommendation.

Q7 What would be the factors that we should take into account that would give us high certainty in forecasted outputs derived through a decentralised approach?

See our response to Q4 which covers a joint response to Q4, Q5, Q6 and Q7 where we set out these factors. Some are repeated here, which all combine to ensure a robust regional approach takes place, a non-exhaustive list is shared below:

- Our sources of information are regional bottom up in many cases;
- Work via Open Networks to develop common approaches;
- Stakeholder engagement and input;
- CEG engagement and challenge.

Q8 Do you consider that the LAEP Best Practice guidance produced by the Centre for Sustainable Energy and the Energy Systems Catapult provides adequate checks and balances to ensure that local or regional energy plans are robust, unbiased and have broad support?

We apply the principles of the LAEP Best Practice checklist in our wider forecasting processes, including how we treat LA/LAEP plans. More specifically, we model LA/LAEP plans via two parallel processes:

- Process A: Projects that are part of Local Authority / LAEP plans where we have received a quotation request (methodology developed under ATLAS NIA project and enhanced afterwards); and
- Process B: Large Local Authority / LAEP projects that are at an early stage (connection quotation request not yet received).

We provide additional information at the end of our response to this question to allow Ofgem to understand a) what checks/implementation processes we adopt to model the likelihood and quantification of effects of LA/LAEP plans on forecasts (DFES used in planning); and, b) how these are in line with all principles of the LAEP Best Practice checklist.

In the wider context of which checklists are applied, it should be highlighted that our main focus is to standardise our forecasting approach and LA/LAEP plans with all other DNOs when producing our DFES, following both our developed ATLAS methodology[8] that is using a transparent and consistent across the network methodology and the agreed framework of the Open Networks WS1b P2 (whole system FES) group in the scenario definition and building block assumptions.

We believe that the LAEP Best Practice guidance and checklist could work as an additional reference to support the credibility of the modelling of LA/LAEP plans in the DFES forecasts that are used in network planning. However, we believe that some elements in this checklist require modifications to make them more suitable for this use. These modifications should include:

- Making it clear that access to source code of the forecasting models can be provided for all methodologies and associated tools that have been either produced in house by DNOs or via NIA/NIC funding that allows them to share it. There are components of these models that are subject to copyright limitations from the consultant experts used to support our modelling, for example the consumer choice models maintained by Element Energy that they have developed for clients such as Department for Transport, BEIS and Energy Technologies Institute;
- Regarding the sensitivity of non-technical factors, it should be made clear that the way the common scenario framework for DFES and ESO FES works is to model uncertainties around two main axes, i.e. societal change and decarbonisation in 2020 works. Therefore, given that this framework cannot capture all associated sensitivities (it’s not a full probabilistic approach followed by DNOs/ESO), the most likely / better justified / best view assumptions are made for any non-technical factors, e.g. availability of e-vehicles by car manufacturers. In reality a request for sensitivity analysis across all factors modelled in forecasts could result in hundreds if not thousands of additional outputs with minor significance given that the major uncertainties are the ones that DNOs aim to capture when defining the scenarios;
- Regarding the engaged stakeholder plans, many of the points in the LAEP Best Guidance are applicable mainly to the LA planners rather than network companies. The guidance highlights the importance of using heat maps, which are used by DNOs mainly to provide insights to

[8] https://www.enwl.co.uk/zero-carbon/innovation/smaller-projects/network-innovation-allowance/enwl008---architecture-of-tools-for-load-scenarios-atlas/

stakeholders rather than as a feedback loop to stakeholders showing which LA/LAEP plans are more mature than others. We follow a universal approach in both our engagement with LAs and how we treat their data (see processes A and B below) and our role is to be neutral and treat all LAs equally, as well as focus on our primary network planning aim that is to assess the growth in demand and generation levels from well justified regional information and concrete LA planning actions.

<u>Additional information on processes A and B in how we model LA/LAEP plans</u>
In both processes we follow methodologies that aim to identify the most likely prediction and assess the associated effects on regional demand and generation growth. More specifically:

- In **Process A**, these projects are mainly HV demand connections and we use confidence factors derived from regional historical analysis to model them as half-hourly through year demand increments. So if, for example, there were 10 quotes for commercial developments of 10 MW total maximum import capacity under the same primary substation in Greater Manchester, using our 2020 confidence factors (to be used in DFES 2020) for HV demand in the south of our region we would apply a 25% confidence factor (36% if it was an accepted quote) for the energisation and then a 40% confidence factor for the demand growth in first year and 41% confidence factor for the second year.

  So, out of a 10MW of capacity for these projects we would model a 25% x 40% x 10MW = 1 MW or 10%. The assigned profile would follow the same profile with the hosting substation, unless there was a specific type of demand where we would assign a case-specific profile. It should be noted that due to the half-hourly through year modelling that we follow, this 1 MW of demand growth would appear as less than 1 MW growth at higher voltages (e.g. 132/33kV BSP substations) due to the difference in the time of peak demand.

- In **Process B**, such projects can be planned developments of wide areas. We would consider these projects only in cases where adequate information through studies and technical analysis can be provided. For example, for a large domestic and commercial development we would not assume that all buildings will be directly populated, and all domestic customers would adopt EVs and heat pumps. We would consider only the LA plans that have well justified assumptions in the year by year demand growth, including information such as:

  - the socio-economics of the area and the affordability of domestic and commercial customers to justify the LCT uptake trends;
  - the assumptions on the diversification of demand of individual customers (need to be in line with national or international standards);
  - the types of loads for commercial/industrial customers and the consideration of the half-hourly profiles of these loads on the demand growth.

Q9 Which of the uncertainty mechanisms and incentives in Appendix 3 will be most effective in enabling efficient strategic investment?

Of the uncertainty mechanisms presented for strategic investment in Appendix 3 we believe the Capacity Volume Driver will be most effective in enabling efficient strategic investment for the reasons detailed below:

- Volume driver with the measurement of capacity is able to cater for all load related drivers, whether that be general load growth, consumer behaviour, LCT adoption, generation or demand connection
- Setting ex-ante allowances with a volume driver to revise allowances based on capacity created/released enables anticipatory investment
- Capacity Volume Driver is in alignment with Ofgem's design principle 24[9]
- Well-designed volume drivers are simple and effective; they can be mechanistic in the way they are able to adjust revenues via annual iteration process rather than an alternative of lengthy reopeners
- Volume drivers are able to provide funding to allow networks to ensure delivery with no blocker for investment
- Customers only pay for what is created, ensuring there are no windfall payments as funding is solidly linked to creating capacity
- Volume drivers can stimulate non-traditional solutions like flexibility and other new innovative approaches to providing capacity because the TIM ensures the most efficient solution will be selected
- Volume drivers are reactive to changing needs and levels of certainty without the need for re-openers
- Decisions will be backed by transparent and robust processes
- Volume drivers are complimentary with other regulatory mechanisms in the ED framework; TIM drives the company to the most efficient solution and there are natural checks and balances via TTQ, BMCS, and new inclusions such as fair treatment for customers and connections

Supported by the majority of other DNOs and stakeholders ENWL has developed the approach of a Capacity Volume Driver for load related expenditure (LRE) in RIIO-ED2. The driver was to develop a mechanism that was simple, easy to understand and apply and facilitates anticipatory investment, whilst ensuring the appropriate consumer protections are in place. The unit rate(s) can be set from the current information on annual RIGs submissions (from DPCR5 and RIIO-ED1) and any trials can be managed through the last two/three years of RIIO-ED1. Therefore, the recording and reporting in RIIO-ED2 of additional units of capacity added to network levels, and their cost will be relatively straightforward. More importantly, when applied in conjunction with the TIM mechanism, DNOs are incentivised to deliver each unit of capacity as efficiently as possible, putting flexibility on an equal footing with network-based solutions and creating a strong incentive to use new ways of providing capacity where cost effective for customers.

Of the other options discussed in appendix 3, our views on each are shared below:

A **Price Control Deliverable (PCD) with funding trigger** linked to regional plans will be unlikely to be able to cover all the eventualities that may occur in a particular area over a five-year period. It would need a granular level of planning for each potential outcome and, as Ofgem states, is more applicable when the solution is known but the need uncertain. This option does not provide sufficient flexibility and would risk DNOs delivering a pre-determined outcome. This may not always be in the best interest of customers and risks removing the option of a flexibility solution which may present itself in period.

[9] "*Where there is material uncertainty in the evolution of quantities (but unit rates are stable) at the start of the control period, volume drivers should be used to adjust allowances within the control period.*" - RIIO-ED2 Framework Decision, RIIO-2 design principle 24, Ofgem

A **re-opener** is akin to the mechanism used in RIIO-ED1; however, as has been discussed in the working groups, there are several reasons why there are better options for RIIO-ED2, such as:

- challenges in setting the predetermined expenditure level and appropriate % trigger;
- time taken to submit re-opener application and Ofgem decision making delaying overall decarbonisation aims and objectives; and
- the risk of disallowance of costs during ex-post assessment may result in companies being risk-averse and limiting anticipatory investment

Whilst we are supportive of the use of a volume driver for strategic expenditure for RIIO-ED2 we do not believe that the use of the **Low Carbon Technology (LCT) volume driver** as described is the most effective solution. A volume driver of capacity provided measured in MWs added is preferential for customers, regardless of the use of the extra capacity, whether for a particular LCT or something else.

Whilst LCT is an important aspect driving investment need, it is only one specific aspect of the expected demands on our network in the future and therefore investment affecting capacity for other reasons would need further separate mechanisms to manage allowances, bringing complexity to the price control. Equally importantly is the fact that LCT adoption is one step removed from DNOs' primary role of providing network capacity to our customers to use for their own needs, whether it is demand or generation/storage. There is no direct correlation between LCTs connected and the work required on the network as this depends on a range of factors such as existing network capacity, clustering, diversity and regional topography amongst other things.

We also note that in RIIO-ED2 a key change will be the increase in the volume of electric vehicles (EV). As such DNOs will need to provide network capacity in various locations to accommodate their charging; for example, at home, at work, at service stations and destination locations. There may be differences between where an EV is registered and where it charges, and this could span DNO areas. It is therefore not clear if, based on LCT, who would account for the additional capacity required in this example of non-static LCT such as EVs. Equally the recording of EVs may be problematical and is outside of the direct control of DNOs.

In the North West we are encouraging our customers and local stakeholders to become more energy conscious and asking them to be more energy efficient, including through the adoption of LCTs for heat and transport, as well as considering generating their electricity from renewable sources. But ultimately it is up to the customer, nudged along by national and local policy changes supporting delivery of the Net Zero carbon targets to lower their carbon footprints. We need to have a mechanism that is flexible and easy to understand and track, and that enables DNO to provide the network capacity required by our customers, when it is needed. This, we believe, is most effectively achieved by the Capacity Volume Driver.

We have reservations on the need for a specific incentive mechanism related to utilisation over and above TIM, but do see the need to ensure that DNOs make the right choices by the reporting and analysis of network utilisation metrics to ensure capacity is created where it is needed at the right time. As previously stated the use of a more disaggregated set of load indices (LIs) applied across all voltage and network levels is the way to achieve this, but this requires full smart meter penetration, or a mix of aggregated smart meter consumption data supplemented with local monitoring.

We would like to work with Ofgem, all other DNOs and wider stakeholders to develop the utilisation metrics and the methods and costs to provide them within the Ofgem Overarching Working Group (OAWG). Metrics might require implementation during RIIO-ED2 and where they rely upon additional monitoring that in itself might be progressively deployed over a longer period than RIIO-ED2 itself.

Q10 Do you agree with our proposals to increase levels of BaU innovation?

In principle we support the objective to increase the levels of innovation delivered through base revenue and incentives as opposed to using a ring-fenced stimulus. However, as Ofgem rightly recognises in its consultation, there are practical constraints on the types of innovation that could be pursued through the base revenue which thereby limit an operator's ability to construct the business case necessary to justify the inclusion of BAU Innovation within its Business Plan.

Naturally BAU innovation will be necessarily limited to lower risk, rapidly deployed projects that seek to rollout previously proven innovative solutions across the network and that will payback within the RIIO-ED2 price control. This will require the innovative solutions that comprise BAU Innovation to be 'shovel ready' at the time of Business Plan submission, allowing the network operator to move the solution into BAU quickly and thereby increasing the period of time any associated benefits are accrued, which will be shared with customers.

Innovative solutions which arise during RIIO-ED2 or those with benefits which accrue mainly, or entirely, to consumers rather than to networks, e.g. Smart Street, would risk not being rolled out without a mechanism such as the Innovation Rollout Mechanism (IRM) in place to support the additional expenditure required. Our stakeholder engagement as part of this response elicited that stakeholders endorse the wide scale deployment of programmes such as Smart Street which, in addition to preparing the network for the future, that will save customers money, without relying on behavioural changes or the need for households and businesses to accommodate new technologies. Therefore, Ofgem should consider a mechanism whereby innovative solutions, which are focused on consumer benefit (at additional cost to the network company when compared to BAU approaches), are able to be rolled out in RIIO-ED2 otherwise customers will see delays to potentially considerable benefits.

As a result of the IRM application within RIIO-ED1, we consider our continued rollout of Smart Street in RIIO-ED2 as being suitable for inclusion in our BAU innovation plans and should be adopted by other DNOs.

Q11 Do you agree with our proposed methodology in relation to the RIIO-2 Strategic Innovation Fund?

We broadly welcome the introduction of the Strategic Innovation Fund (SIF) as it appears to widen the innovation focus beyond the electricity networks, including other energy vectors such as heat. This would appear to have the potential to allow for the funding of projects not currently allowable under NIC, such as those beyond the electricity meter, which are of net benefit to consumers.

It is important however to obtain a suitable balance between complexity and deliverability, and to avoid the SIF becoming overly expansive and as a result increasingly hard to prepare and, ultimately, deliver projects.

We would also be particularly keen to ensure that projects such as CLASS and Smart Street, which stand out as having strong customer benefit cases, and are highly innovative in nature, remain viable for funding through SIF. Both these projects include highly technical, network centric deliverables, not necessitating or requiring the element of co-ordination and collaboration perhaps envisaged within the SIF but, owing to being beyond the scope of NIA, wouldn't have been possible to progress without NIC. In introducing the SIF as a replacement to NIC, Ofgem should seek to ensure that projects such as CLASS and Smart Street don't inadvertently fall between the gap in innovation funding (i.e. between NIA and SIF).

We look forward to learning more about SIF and having further opportunity to comment on its practical application in due course. We note the SIF is ambitious, and there will be lots of work needed to ensure the processes are well understood, practical and ultimately fit for purpose. Similarly, it is our view that ongoing support and regular review will be required to ensure SIF delivers its aims throughout the period of RIIO-2. Ofgem need to be cognisant that this might attract a considerable overhead dependant on the requirements.

We would add that there are a number of references to the Net Zero Advisory Group and the Net Zero Innovation Board, however there is currently limited visibility on these and would encourage greater transparency on these bodies, their composition and role in innovation within the energy sectors.

Q12 Do you agree we should adopt a consistent NIA framework for DNOs, and other network companies and the ESO?

We are supportive, in principle, of this approach in that the innovation framework for RIIO-ED2 should allow interaction with other sectors.

Work on developing industry innovation strategy together with the use of the single allowance for the length of the price control[10] ought to go a long way to helping collaboration and consistency where in consumers' interests.

Given the RIIO-ED2 price control will be set two years after the other sectors, it is important to ensure that the desire to set the NIA framework consistently for all sectors does not result in it being too fixed for ED. It is entirely possible that the passage of time brings a greater understanding of the necessary innovation focus for ED, and it should be possible to reflect this within the RIIO-ED2 NIA framework, even if that means it is not identical to the other sectors.

Q13 What are your thoughts on our proposals to strengthen the RIIO-ED2 NIA framework?

We believe the proposals to strengthen the RIIO-2 NIA framework are sensible and the direction of travel for NIA is consistent with the broader aims of stakeholders. To appropriately satisfy these aims, the drafting of all associated changes to the NIA governance document will be crucial, ensuring that the strengthening is effective and as intended. We believe the ENA and its member companies can add considerable value to this process, and we are pleased to note Ofgem's intention to hold workshops on drafting updates to the governance.

We are comfortable with the proposals that eligible projects should be focused on issues associated with the Energy System Transition (EST) or that they seek to address a particular consumer vulnerability. We consider this narrowing of the focus from that of RIIO-ED1 to offer potential for better alignment across networks thereby increasing the opportunity for collaboration between companies. However, as with any change to the eligibility criteria, there is a danger that a project, such as transformer oil regeneration, which sought to introduce a viable method of extending the safe operating lifespan of transformers and which is now BAU, would not meet the new proposed qualifying criteria for NIA, nor, owing to its being a high-risk, long-term project, would it meet the expected threshold for BAU Innovation.

[10] RIIO-ED2 Methodology Consultation: Overview, paragraph A4.22, Ofgem

Given this, we believe that careful consideration of the appropriate definition of EST and, for similar reasons, customer vulnerability should be given so as to avoid potential for innovations such as oil regeneration being considered ineligible for funding thus risking innovative projects like this not being done at all. Clearly, such an outcome would not be in the best interests of vulnerable customers and customers more generally who might otherwise have benefited from the increased efficiencies.

We are broadly supportive of the proposal to require all NIA projects to develop solutions that deliver net benefits to customers in the relevant sector as it is these customers that pay for the projects in the first place.

We are pleased to see inclusion for consideration of the impact of innovation upon vulnerable consumers. This is an important development and one we aim to address in part through our Smart Street project which, through its reductions in energy consumed, is expected to deliver significant savings to over 20,000 vulnerable consumers during RIIO-ED1 and continuing into RIIO-ED2. Further one of our stakeholders stated that they “support the focus on innovation stimulus funding on addressing consumer vulnerability.” Further they “agree with the Ofgem proposals to provide support for innovation that DNOs would not otherwise undertake, where this addresses the key strategic challenges that are raised by the decarbonisation agenda or provides support for vulnerable consumers.”

We fully support the aim to increase third-party involvement in NIA. It’s crucially important that all network operators continue to engage fully and effectively with third-parties as appropriate on network innovation.

On proposals for the development of a collective guidance document for third-parties covering IP, we are not convinced that this will address the issues of inconsistency between DNOs that is its stated aim. Matters of consistency in application of the governance document are perhaps best addressed through the collaborative working between organisations, most probably via the ENA, to agree, for example, a set of common legal terms covering IP, which can be understood and adopted across all parties seeking to draw upon NIA. This could form part of planned future work on re-drafting of the NIA governance document.

Q14 Do you have any additional suggestions for quality assurance measures that we could introduce to ensure the robustness of RIIO-2 NIA projects?

Whilst needing to avoid costly post-project completion reviews which would appear to offer only limited value, particularly given the high volume of NIA projects, we broadly welcome the addition of quality assurance measures in respect of the robustness of NIA projects in RIIO-ED2. To add most value this ought to happen at the start of the process during project registration and continue through its delivery.

We consider quality assurance is most effectively and efficiently achieved through self-auditing of projects, including within this all aspects of NIA project reporting (i.e. project registration and annual and final reports). Further, we believe the ENA can play a key administrative role in this, perhaps through facilitating an ‘annual audit report’ of the portfolio (or a selection based on theme) of NIA projects.

Furthermore, individual network operators ought to consider establishing ‘innovation links’ with a network of relevant stakeholders (perhaps including Local Authorities, Universities and technology providers) who could be approached to provide the necessary quality assurances being sought.

Q15 Do you agree with our proposed approach for setting individual levels of NIA funding?

We strongly agree with this approach. Throughout RIIO-ED1 ENWL has consistently found its innovation ambitions constrained by its 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 ENWL has 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 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. In RIIO-ED2 our Business Plan is likely to include a higher allowance for innovation than was provided in RIIO-ED1 and Ofgem's proposal to set levels individually would appear to support our innovation ambitions.

4 Modernising Energy data

Q16 Do you agree with our approach to regulating digitalisation and better use of data through the introduction of cross-sector licence obligations?

We broadly agree with the approach taken in this area and provide our further comments below on the definition and strategy set out within the SSMC. The one element we would change is the update frequency on the digital action plan progress which should be reconsidered.

<u>Definition</u>
With reference to the statement "Digitalisation, in this context, means making better use of energy system data and digital technologies to generate value for consumers and stakeholders more generally."[11], whilst we generally agree we would expand this to include the transformation of business processes and associated business change for a true digital transformation. Digitalisation should not be solely about data and technology but also about people and process.

<u>Strategy</u>
In terms of the Digitalisation Strategy in December 2019 we took the decision that, along with voluntary publication and submission to Ofgem, we would also publish a consultation document to gather feedback from stakeholders. We are in the process of refining the strategy following that feedback and extensive internal review for future publication. We are happy to follow this publication approach as defined by Ofgem within the SSMC.

<u>Licence Obligations (LO)</u>
We understand that Ofgem considers that a LO on a Digitalisation Strategy, Action Plan and adoption of best practice are expected to bring benefits in line with Energy Data Task Force findings however

[11] RIIO-ED2 Methodology Consultation: Overview, paragraph 5.1, Ofgem

more work needs to be done to understand how energy data is used by stakeholders before we can say how and to what extent benefits will flow through to consumer benefits.

Ofgem's area of focus is on data rather than business transformation through digitalisation. We have taken the route of producing an overall digitalisation strategy with a data strategy being a sub-strategy to that. With the proposal to make the publication of these strategies and action plans a licence obligation there is more work to do to clarify what the focus of the strategy should be and what standards are relevant. There are many views as to what good looks like when it comes to strategies for data and/or digitalisation and a better understanding of how companies will be measured on this is required. We welcome the opportunity for greater discussion on this and recommend this takes place via the ENA Data Working Group and that further clarity be provided within the Sector Specific Methodology Decision (SSMD) due later this year.

If the real need is for data strategies, then we would propose that a thirteenth EDTF data best principle could be "the development and maintenance of a data strategy".

With regards to the proposed frequency of publication, we agree with the two-yearly frequency for publication of the strategy document but feel the six-monthly requirement for the publication of the action plan is too frequent. Such frequency will place a significant burden on companies in terms of preparation and approval for external publication and will result in engagement fatigue quite quickly.

Opening up our data and being transparent in terms of justification for sharing, data quality and coverage, would make it significantly easier for third parties to hold us to account. We think this could be better for consumers and stakeholders, further enhancing confidence in our actions and may in turn facilitate a lighter touch in terms of regulation as capabilities mature and stakeholder and consumer groups have better visibility of what we do and how we perform.

We are aligned to the principles of best practice guidance and the principle of presumed open data, triaging such data and building this into governance structures will be the next steps we take.

We caution however that some aspects of the guidance will bring significant challenges and compliance costs and this needs to be considered when allowances are set in this area. Uncertainty over the standard approach to be taken means that companies may not be able to fully estimate the work involved in transitioning to a standard specified model.

The subject of data which networks do not routinely collect but may be requested by stakeholders also needs to be considered, with guidance and expectations to be shared so that companies and stakeholders are clear on areas of responsibility and funding.

There also needs to be consistency across companies with regards to triage and what data sets are gathered and published.

We welcome the EDTF best practice guidance and consider the concept of working from a state of "presumed open" rather than from "presumed closed" a good approach to encouraging data sharing, insight and innovation. We are a proactive contributor in the industry wide 'Data working group', recently established by the Energy Networks Association (ENA). This group focuses on the digitalisation of the networks across electricity and gas, including provision of network data in line with the recommendations of the Energy data taskforce. We are working with other members to identify new data fields, or value from existing datasets to maximise benefits for consumers.

We do recognise some of the challenges of working towards the EDTF recommendations and following some of the data best practice principles. There is a risk that meeting EDTF recommendations could drive up network company costs to serve consumers, without clear benefits that are known at this stage.

We welcome Ofgem sharing their view of the risk that is appropriate for customers in how much they fund network company activities delivering EDTF recommendations against potential benefits that may arise, often outside the sphere of the network company's own activity where cost arises or where benefits might be risky and uncertain.

5 DSO Transition

Q17 Do you agree with the proposals we have set out to support optionality for wider institutional change should we later decide to separate DSO functions from DNOs? How else could the methodology support optionality?

We support the proposed approach to develop the optionality for institutional change by placing requirements on network operators to record and report costs and outputs in those areas identified through Business Plan submissions and industry agreement.

This however, should be the only proposal taken forward in RIIO-ED2; we do not support or believe there is a need to introduce a re-opener for separation in RIIO-ED2 as it is too soon to consider fundamental restructuring of the industry. RIIO-ED1 and the RIIO-ED2 price control periods are the opportunity for the DNOs to develop and hone the tools and techniques needed to fulfil the new DSO functions and activities on the journey to Net Zero. ED3 price control discussions should be the time to consider whether it is appropriate for a revised industry structure. There are other regulatory approaches including additional licence requirements that are available to Ofgem and would be more proportionate than revised industry arrangements.

The substantial work undertaken in the ENA Open Networks project revealed that RIIO-ED1 and RIIO-ED2 are the time periods for the industry to work in collaboration, co-ordinating activities for whole system outcomes whilst developing the new skills, tools and techniques to deliver distribution system operation functions and activities. RIIO-ED2 is an important period of transition and system and network operators should be allowed to develop within the framework set out by the regulator with those companies continually striving to deliver efficient outcomes, as agreed with their customers and stakeholders, through innovation being rewarded.

RIIO-ED2 may also be a levelling period. Customers' needs and associated network issues have occurred quicker in some regional areas, such as PV in the South West, driving the implementation of active network control there in advance of areas with lesser customer uptake of DG. It would be inappropriate to consider industry restructuring until all DNOs have had the opportunity to evidence their capabilities, and it may not be necessary to separate all DSOs from DNOs as some companies may be performing more effectively for customers than others.

Q18 Do you agree with our proposal to use the Business Plan Incentive to encourage companies to reveal standards of performance higher than our baseline expectations in their DSO strategies? Do you agree we should require, where appropriate, all DNOs adopt these revealed standards?

We support the proposed approach to include the DSO strategy elements of the Business Plan submission within the Business Plan Incentive (BPI). This will drive companies to include challenging proposals to undertake the new DSO roles and, where appropriate and supported by customer and stakeholder evidence and preferences, exceed the baseline expectations as outlined by Ofgem.

Caution should be applied where companies submit deliverables and outputs that exceed baseline expectations and where these are considered for wider adoption by the industry. This could undermine customer and stakeholder engagement if incorrectly applied. There are distinct regional differences between DNOs which will mean that the pace and nature of DSO transition will differ. It has already been seen that where some DNOs have excelled within integrating new/extended DSO functional activities, driven by the particular needs of their stakeholders, others have not yet seen the underlying driver for these functions to be developed into BAU. Due consideration should be made that DNOs should aspire within their Business Plans to transition to integrate enhanced DSO functionality at a pace which meets their stakeholders needs and should not overdeliver for the sole purpose of keeping pace with other DNOs, thus resulting in inefficient investment.

Additionally, one element cannot be pulled out in isolation as plan costs and outputs are interlinked. It would be inappropriate to simply apply or increase standards without consideration of the impact of costs to deliver those additional performance standards. Costs from one DNO cannot be assumed to be applicable to other DNOs, as some DNOs are already needing to adopt more advanced operations and have a different starting point, for example, some DNOs are further forward on development of ANM, utilising the same capacity across a range of customers using time series analysis whilst this is an emerging requirement at Electricity North West.

Q19 Do you agree with our proposal to invite companies to provide metrics and performance benchmarks in their DSO strategies?

Yes, we support the proposal for companies to provide metrics and performance standards as part of their Business Plan.

Q20 Do you agree with our proposal to introduce a DSO ODI in which we would via an ex post incentive, penalise or reward companies based on their delivery against baseline expectations and performance benchmarks? If so, what criteria and other considerations should we take into account in determining whether we should apply a reward or penalty?

We support the proposal to introduce a DSO ODI as long as the chosen metrics and performance standards support consumer outcomes, are applied consistently across the industry and are appropriate for the regional circumstances. For example; a simple metric of volume of flexibility services contracted would not be appropriate as larger DNOs and those with more constraints to solve could look positive under this metric compared to those who have capacity available to use without any funded interventions.

As RIIO-ED2 is likely a transition period for DSO we believe that any incentive framework should, at least initially, be a reward only. As experience of DSO functions and activities mature the incentive framework could be a penalty/reward mechanism with the value increased if it returns multiples of value back to customers. Generally, we would support national benchmarking of common activities. There may however need to be consideration of bespoke benchmarking for some DSO related activities per DNO where these activities are shown to not be common or when the DNO is starting from a significant advantage/disadvantage position at the start of RIIO-ED2 based on their regional requirements and/or customer and stakeholder priorities and preferences.

It is proposed the value of reward is material enough to drive network operators to find innovative ways to deliver higher performance standards over time, but again companies shouldn't be penalised for understanding and reflecting customer and stakeholder requirements and priorities which may be different to those perceived as being more pronounced needs in other areas of the UK where this is required and supported by customer and stakeholder engagement. Doing the right things for customers should be rewarded, including going at the right pace for the regional circumstances and taking proportionate actions to the scale of issues being tackled.

Reward of delivery activities should take into consideration the net benefits delivered to stakeholders, rather than simply looking to keeping pace with other DNOs. Due to regional variations in network architecture and consumer patterns there may be more requirement for some DSO functionality to be integrated into business as usual within some DNO licence areas earlier than within others. These regional differences can also generate different problems with the delivery of DSO functionality, e.g. variations in market liquidity of DERs to provide flexibility services. DNOs however should, as much as possible, be looking to standardise user experience nationally, where this is shown to be delivering best practice.

Q21 Do you agree with our proposal to undertake the ex post initiative performance assessment in the middle and at the end of the price control? Do you think the assessment should be more or less regular?

We do not support the proposal to only evaluate the DSO ODI twice within RIIO-ED2 through an ex-post mechanism.

As it is continuous improvement through well devised and executed plans that reflect our customers' and stakeholders' expectations, our preference is that the assessment should be ongoing throughout RIIO-ED2. The monitoring and reporting mechanism should be through the annual RIGs submission, accompanied by the appropriate commentary and justification.

The expectation is that there would be a reward assessment every year.

Q22 Do you have views on how we might set appropriate values for rewards and penalties associated with the DSO ODI?

Introducing a financial ODI to a new business area needs careful consideration when setting rewards/penalty values. We are attracted in principle to the suggestion within the consultation of linking the values to a percentage of costs associated as DSO as this clearly segments out from other activities and costs. However, this does assume a high accuracy of cost allocation which is unknown at this point.

We welcome further discussion on this element of the DSO framework between now and the SSMD as the proposals on DSO Business Plans develop and we have greater understanding of how the Business Plan Data Templates can work for DSO costs.

Any financial ODI should be set up with a potential reward scope sufficient to incentivise strong delivery and ensure the necessary focus and effort by a DNO. This will drive network operators to continuously develop innovative ways to deliver ever increasing performance standards overtime.

Q23 Do you agree with the DSO roles, principles and associated baseline expectations in Appendix 5? Does it provide sufficient clarity about the role of DNOs in RIIO-ED2? Do you think amendments or additional baseline expectations are required?

The additional information on DSO roles, principles and baseline expectations contained within the Appendix 5 has been useful in understanding the direction and framework development for RIIO-ED2. Without this information the network operators would have been left interpreting the DSO functions/activities provided by Ofgem in its position paper, published in August 2019. The information provided by Ofgem gives more clarity of its expectations of DSOs though we expect Ofgem will need to take consultation responses from a range of stakeholders into account and will update these roles, principles and baseline expectations in the SSMD.

Our concerns and the areas we wish to focus on are the metrics and ways of assessing DSO performance applied to the RIIO-ED2 period.

6 A Whole system approach

Q24 Are there any electricity distribution specific barriers to whole system solutions, and if so, are there are sector specific price control mechanisms to address these?

We have not identified any ED specific barriers to whole system solutions at the present time, however, we highlight the below considerations, some of which are specific to ED and will need solutions to be in place for RIIO-ED2, and others which are cross-sector considerations.

<u>ED specific considerations</u>
We agree that the approach should be broadly consistent across all sectors to ensure true whole system thinking, however it is clear that the ED sector differs from other energy sectors when considering Whole System. Whilst other sectors also face their own challenges, the combined forces of decentralisation, digitalisation and decarbonisation undoubtedly impact ED uniquely.

ED is generally affected first by external drivers where the pace of change observed on our network is faster than that observed elsewhere in the regulated energy sector. As a result, there is a continued and urgent need to engage with specific stakeholders and significant decision makers so that companies' business plans can be driven by regional aspirations, differing rates of change, development, policy and ambition. Therefore, even within DNO service areas there will be regional differences and subsequently drivers for potential of differing approaches to whole system thinking that need to be recognised and understood.

It is therefore essential that the RIIO-ED2 framework enables whole system thinking to be taken forward with the appropriate incentives, an investable regime and the funding of new activities to ensure the benefit is accrued for consumers.

Some of the potential issues facing the sector which will benefit from whole system co-ordination are still dependant on government policy. Whilst we welcome the concept of the Net Zero Advisory Group (NZAG) it is unclear precisely how this will work and what the pathway is for decisions and the implementation of such decisions. That said it should generate increased co-ordination between BEIS, other government departments and Ofgem ultimately aiding Ofgem in making price control decisions with the best possible view in this period of uncertainty.

Within the RIIO-ED2 period a flexible approach is needed from DNOs and Ofgem, where networks can learn by doing, and implement such learning to ensure continuous improvement, sharing of good practice and common approaches where these are appropriate.

One advantage of having 5-yearly price controls, with a timing difference between GD/ET and ED, is that the approach to whole system is also able to naturally evolve and can be a way of reducing barriers.

Anticipating there will be some insights within BEIS's white paper in Winter 2020/21 and certainly by RIIO-ED3, we expect to see a firm government policy decision on the decarbonisation of heat, clear direction on hydrogen development and greater exploration of the benefits of greater co-ordination across energy vectors. Therefore, we expect to see the benefits of the learning and progress made within RIIO-ED2 which will see benefit arise in the following regulatory period. Transparency on whole system decision making and governance is important for all stakeholders.

<u>Scope and CBA</u>

First and foremost, it is important that there is a clearly defined scope and ambition for RIIO-ED2, including importantly, what is meant by whole system benefits and where these accrue (i.e. with DNO customers, other sector customers, or wider societal benefits). It is important that this is in place by SSMD so that companies are better able to incorporate their whole system thinking, planning and processes within their RIIO-ED2 Business Plan proposals.

Definition of whole system activities is essential. For example, our current approach of going to the market for flexibility could be deemed as a whole systems approach because other network operators are also able to offer solutions.

Benefits in terms of lower costs to the DNO of whole system collaboration may not always be brought by an asset or flexible based solution, but rather often manifest themselves in avoided future costs or they may actually have higher costs now for the DNO, but lower whole system costs in due course. Potentially totex savings might arise and be treated under TIM as savings in a network elsewhere. Consideration of the timing of interventions, collaboration and planning are not routinely recorded or quantified by companies. It will be important to consider what Ofgem is looking for in companies demonstrating these outcomes and to what end.

It is equally important that Ofgem in its decision making, timing and stability of decisions clearly signposts where there are any impacts on whole system solutions or services which may be provided. There are a number of policy decisions on DNO participation in certain services, such as aggregation, storage or ancillary services, and it is important that any future review or areas considered which impact on whole system outcomes are signalled early and are equally well co-ordinated.

We need transparency and a clear view of compliance with the whole system licence condition, as well as fair application and material rewards linked to consumer benefits enabled.

We have stated previously that one of the key enablers for whole system decision making is the existence of a whole system cost benefit analysis (CBA) and careful consideration is needed as to what and how this is captured within a CBA model. We are seeing greater emphasis from local authorities in their CBA thinking on societal benefits and economic cost of disruption for example. We support the inclusion of wider benefits, however, as we have stated earlier in our response, companies need to have clarity and guidance as to what criteria they must consider when making their operational and investment decisions. Some options may be delivered at greater cost to DUoS customers but show net benefit to other sectors, or net societal benefits. How such decisions should be assessed and how these can feed into company business plans need to be set out as soon as possible. We recognise the positive work being undertaken by the Open Networks Whole System workstream and urge Ofgem to continue their involvement in this, including taking a more active role in its product development to ensure that the outcome is a transparent tool that networks and stakeholders can use and understand.

Finally, many details of whole system solutions are yet to be resolved as evidenced by the issues coming out from our support of the ESO's Pennine Pathfinder project. Our network currently hosts providers of services to the ESO and whilst the contract will be between the provider and ESO, our network is a vital link. Changes to the topology of our network may potentially affect some service provision from time to time. This could theoretically improve the benefits so there may be new opportunities and considerations in the way we manage and develop our network. These considerations already exist on the transmission network where the ESO may need to co-ordinate with the TO regarding service provision.

Work is underway within Open Networks to identify and ensure that the appropriate data is available to allow each party to fulfil their duty for Whole Systems consideration.

At ENWL, we continue to review and reinforce separation arrangements across the business to ensure that the teams undertaking this work are separate from other teams where appropriate.

<u>Review of DRS mechanism</u>
The existing Directly Remunerable Services (DRS) has been used appropriately within RIIO-ED1, however we have recently identified some limitations when it comes to whole system approaches.

There are recent examples of DNOs meeting Transmission or System Operator needs which have been arranged on a commercial basis, such as the Accelerated Loss of Mains project. It was agreed with Ofgem that DRS9 would be used to manage costs associated with the programme. However as this is a miscellaneous category which could contain a range of activities which don't naturally fit within one of the other DRS categories, it is worth reviewing the categories and potentially creating a 10th DRS category which is specifically to accommodate commercial transactions across networks. The goal would be to ensure there are no barriers to using DRS as a route where projects do not merit CAM applications. This will further support the aim of transparency and ensure activities are not mixed in with other reported costs.

<u>Equitable cost arrangements</u>
It is likely that networks can be the recipients of solutions from other licensees and also provide services to others. This will naturally incur additional costs as we both develop solutions for resolution of issues on others' networks, and also evaluate solutions for issues on our network from other licensees. Experience will be necessary to quantify these as well as a fair and equitable way of recovering such costs to ensure that no company or sector ends up with undue costs.

<u>Benchmarking and cost assessment</u>
Care should also be taken when benchmarking companies' proposals; as low cost for one company may not equate to low cost for the whole system. Different whole system solutions should ultimately be compared through the same assessment lens.

Q25 Are there any electricity distribution specific issues you think should be accounted for in the Business Plan Incentive?

We support Ofgem adding clarity for the areas under the Business Plan Incentive and we expect that more dialogue and clarity will be needed through working with Ofgem to understand what will be rewarded/penalised. Through the ENA, we have suggested a RIIO-ED2 working group meeting is dedicated to walking through the process Ofgem intends to follow in assessing the Business Plan Incentive.

As we propose in our cover letter, care should be taken to not stifle DNOs ambition by being overly prescriptive in the CVP guidance. We propose areas such as Smart Street and leading decarbonisation should be included in the list of areas to be included. This is supported by our stakeholder engagement on the SSMC where one stakeholder response specifically set out that “ENWL should take a proactive approach to supporting the North West to achieve Net Zero”.

Because the incentive currently only focusses on five areas, as per our comments above we think this might be too restrictive and therefore suggest that whilst the guidance is helpful, it should not restrict a DNO from putting forward a business plan measure that results in a reward if that measure is supported by customers and stakeholders and the company’s CEG. Any aspects not within the five specified areas will need to be fully justified from a consumer perspective as to why they are included.

Q26 Do you agree that whole system solutions are relevant to the innovation stimulus?

Yes, we agree with this approach. Without whole system thinking, collaboration and planning it may narrow the innovative solutions researched and developed which is not in customers best interests.

To ensure best value for customers in the energy system transition it is important to consider solutions which are not wholly devoted to one energy sector. For instance, in some areas it may be more beneficial to switch customers to a cleaner form of gas than to change their heating systems to an electric heat pump but in other areas the reverse may be true.

Q27 Do you agree with our key proposals for the CAM?

As we explained in our recent response to the DD consultation, we believe that it is essential that whole systems outcomes are, as a minimum, not precluded by regulatory arrangements and, where appropriate, should be strongly incentivised to ensure that all network companies are focussed on delivering the most optimal outcome for all relevant consumers.

From discussions with Ofgem we are anticipating that the Co-ordinated Adjustment Mechanism (CAM) is designed as a back-stop solution to be used in rare circumstances rather than one expected to be used commonly as fully formed plans should be developed by companies including consideration between all stakeholders as to which outputs and allowances should be set.

The approach Ofgem has taken in DDs by excluding any uncertain investment, instead preferring the use of uncertainty mechanisms means that the CAM is even less likely to be used as only those certain costs and projects are allowed in baseline expenditure. This results in the likelihood of another network being able to offer a whole system solution to the overall benefit of customers being even lower.

In light of this, and the potential complexity of the CAM and its timings, we believe Ofgem should consider whether there is sufficient justification for the inclusion of this mechanism within RIIO-2. If Ofgem does decide that the mechanism is required, we believe it should be developed bilaterally with companies. This is contingent upon Ofgem retaining the view that CAM is a mutual company consented mechanism where this is triggered by a single company.

Consideration needs to be given to projects identified within company plans, or that emerge within period where a whole system solution is identified but due to the wider use of UMs no licensee has the ex-ante allowances/output obligation to be able to transfer it. A licensee triggering the UM to receive the funding adjustment in order to then transfer it to another licensee appears impractical. Therefore there is a need for some method whereby the company delivering the solution is able to have its revenues and outputs adjusted to take into account the new obligation. As it is currently designed the CAM is not able to do this with its prime purpose being transferring revenue and outputs from one licensed entity to another. The Net Zero re-opener could be one potential solution but would need to be modified so it is able to allow companies as well as Ofgem to trigger this re-opener.

We make further comment on the CAM below:

We consider the CAM only being applicable to asset-based solutions as flexibility-based solutions, or other such services, will be managed on potentially shorter-term timescales through commercial arrangements. As we discuss in our response to Q24 the existing RIIO-ED1 DRS arrangements should be reviewed to ensure that such arrangements can be accommodated within the regulatory framework.

We agree with there being no materiality threshold, instead there is a focus on ensuring customer benefit, and we agree with the logic that companies would not progress with an application where benefits are speculative or hard to demonstrate.

Whilst we acknowledge that there will be a licence obligation (LO) on whole system co-operation and collaboration within RIIO-2, incentivisation within this area will further support the drive of focus towards whole system solutions and ensure that companies see the broader benefit of a CAM application. We support the intent of companies agreeing compensatory value associated to the risk of any transfer and that a share of any intended benefits is agreed within the commercial terms between companies when undertaking the CAM proposal. We strongly urge that guidance associated with the CAM is shared ahead of the price control commencing so that there is clarity over expectations. We also believe that greater clarity is still required on what Ofgem will consider as customer benefits and treatment where benefit falls outside of the sector enabling the solution.

We agree with the proposal of application from one licensee, with a statement of agreement with the other licensee. We also agree that this should be network triggered only as a collaboration and not required or initiated by Ofgem on one or both licensee.

We have previously stated that one of the key enablers for whole system decision making is the existence of a whole system cost benefit analysis (CBA) and so are pleased to see this being covered within the Open Networks work, as well as sector specific CBA work. It is important that Ofgem is involved in this work and considers its use within CAM assessment as companies need to have clarity and clear guidance as to what criteria they must consider when making their operational and investment decisions. Without this clarity in place and a supportive whole system CBA there is no ability to quantifiably conclude that the solution selected is the most efficient given whole system consideration.

We would add that companies have previously raised the subject of costs associated with exploring whole system solutions, preliminary studies and other preparatory work that would need to be undertaken on a routine basis ahead of any CAM application being considered necessary. We understand that the costs for any applications which go ahead would be included in the CAM, but there is also likely to be a range of costs associated with exploration of options that do not go ahead and therefore sit as aborted costs. These will be incurred by all companies as they seek to embed whole system exploration in their BAU approach however these are not costs that would have routinely been incurred in RIIO-1 and need to be considered within company's overall totex allowances. Guidance over expectations on whole system collaboration and where costs are borne by for example DNOs to support TO exploration or vice versa is required to ensure equitable arrangements are put in place.

We believe the next step in development and assessment of the CAM will be for Ofgem to stress test the CAM under a range of scenarios/case studies to see whether the issues raised in our response can be appropriately managed.

Q28 Do you consider that two application windows, or annual application windows, are more appropriate, and should these be in January or may?

Careful thought needs to be given to this question given the timing difference of the RIIO-2 period with the other sectors. The DD consultation currently considers years 2 and 4 as potential windows. We take this to mean submissions in May 2022 and May 2024 (or possibly January in line with Ofgem's proposed common position on re-openers).

In our DD response we have questioned the usefulness of a re-opener in year 4, given that any decision and resulting change in revenues will likely happen too late in the period to have any effect or allow delivery to take place. We have therefore suggested alternatives being in year 3, so May 2023.

We also see little merit in the 2026 window for ED, as this would only allow DNOs to transfer amongst their own sector, whilst GD/T will be entering RIIO-3 and any delivery via another network would already be factored into their business plans. This brings us back to our first point that if revenues and outputs are not set up-front in companies' allowances, the CAM prime objective of transferring these is not possible and another funding route needs to be explored.

The table below shows Ofgem's current DD/SSMC positions.

Network	Application Window
Transmission/Gas Distribution	May 2022 (year 2 for GD/T)
Transmission/Gas Distribution/Electricity Distribution	May 2024 (year 4 for GD/T) (year 2 for ED)
Electricity Distribution	May 2026 (year 4 for ED)

Given our view that 2024 is too late for GD/T and 2026 is limited for ED as the other sectors will be in RIIO-3, this would suggest that the window is best set the same for all sectors, as otherwise it inadvertently dictates which sector should trigger the mechanism.

Timing is probably best to be 2023 for all sectors and for anything beyond 2025 where the other sectors are entering RIIO-3 a method of adjusting the RIIO-ED2 allowances needs to be considered where a DNO is identified as best placed to deliver a project in the period 2026-2028. How the CAM works in practice can then be reviewed ahead of RIIO-3, based on experience.

Q29 Do you consider that the current electricity distribution licences should be amended to include CAM, or wait until 2023 at the start of their next price control?

We believe our proposal to place the CAM window in 2023 for Gas and Transmission would be sufficient without the need to make changes to the RIIO-ED1 licence.

7 Access Significant Code Review and Impact on RIIO-ED2

Q30 Do you agree with the impacts of our potential Access SCR proposals that are identified in this chapter? Are there additional impacts that are not identified?

The impacts listed in Table 13[12] show the potential beneficial impacts of these reforms but do not mention the associated implementation costs and downside risks. Our view of these include:

- **Review of the definition and choice of access rights for distribution users**
  As requested in the Access SCR Request for Information, depending on what is set out in the Minded-to Consultation there may be implementation costs to deliver these proposals.

- **Review of the electricity distribution connection charging boundary**
  Again, depending on what is set out in the minded-to consultation there may be implementation costs for the proposals.

  With the proposals themselves, if there is a move to a shallower connections boundary, then this would add to the uncertainty on the number of new connections that are to be expected in the price control period.

  If connection charges are recovered over time, this will have cost impacts and will also introduce a level of bad debt risk that is not a factor in current upfront connection charges and could affect financeability. Extensions assets are outside of price control so DNOs may not be able to access finance at same rates when not secured against the RAV.

  For clarity we believe changes in the connection boundary would be recovered through customers generally through DUoS. Deferred payment of connection charges would still be recovered from the person requesting the connection, except for any bad debt which we'd also expect to be recovered through DUoS.

- **A wide-ranging review of distribution network charges**
  Again, depending on what is set out in the minded-to consultation, there are likely be implementation costs associated with these proposals, with some of the more granular charging approaches likely to drive significant costs. If the implementation date is for the start of RIIO-ED2 then consideration should be given as to how any costs incurred in RIIO-ED1 ought to be recovered, e.g. through some form of logging up process.

  With the proposals, Ofgem expect that they could reduce the need for network reinforcement. Whilst this is a possibility, we do not believe there is any current evidence to support this assumption, and therefore this would add to the uncertainty on the number and the need for network reinforcement that is to be expected in the price control period.

[12] RIIO-ED2 Methodology Consultation: Overview, table 13 below paragraph 8.4, Ofgem

- **A focused review of transmission charges**
  Again, depending on what is set out in the minded-to consultation there may be implementation costs associated, particularly if DNOs are required to pass through transmission charges to suppliers or customers.

Alongside this there are potential areas of the BPDTs that could be affected are:

- 11 S1 - Performance Summary
- 34 C2 - Connections Inside PC
- 35 CV1 - Primary Reinforcement
- 36 CV2 - Secondary Reinforcement
- 37 CV3 - Fault Level Reinforcement
- 38 CV4 - NTCC
- 60 C4 - IT&T (Non-Op)
- 116 C20 - Connections Outside PC

We acknowledge that Ofgem recognises the potential impacts of the Access SCR in the Time to Connective (TTC) Incentive proposals set out in Annex 1 with potential penalties being deferred until the effect on customer behaviour is clear and we support this approach.

Q31 Do you agree with the proposed Access SCR baselines for the RIIO-ED2 business plan submissions (ie that Draft RIIO-ED2 Business Plan submissions should use Access SCR Minded to Consultation as a baseline, and that Final Business Plan submissions should use Access SCR Final Decision as a baseline?)

We agree with the proposals to use Access SCR minded-to consultation as a baseline for the draft Business Plan submissions due to be submitted to the RIIO-2 Challenge Group on 1 July 2021. We also agree with the use of the Access SCR final decisions as a baseline for final Business Plan submissions to Ofgem on 1 December 2021.

Q32 How do DNOs propose to demonstrate the impact of our Access SCR reforms on RIIO-ED2 Business Plans?

We would expect to include the estimated costs of implementing the decisions. It may be beneficial if these were separately identifiable in the BPDT. We would not propose to include any behavioural impacts of the proposals in either of the Business Plan submissions as there is limited evidence to justify inclusion. Any behavioural impacts will be picked up in the uncertainty mechanism for treatment of strategic investment (UM) as Ofgem refer to in Appendix 3. For example, the connection charge proposals could affect the volumes of LCT connecting and the DUoS proposals, as well as the amount of spare capacity in the system. It is not appropriate to have a separate UM to deal with the Access SCR specifically, though the capacity volume driver mechanism (for example, as illustrated in Figure 7[13]) needs to reflect that in some areas price signals may have reduced capacity, but this wouldn't mean that reinforcement in other areas is not justified.

[13] RIIO-ED2 Methodology Consultation: Overview, figure 7 below paragraph A3.18, Ofgem

Q33 What further guidance might be required from us to allow DNOs to identify the parts of their draft Business Plan submissions that could be impacted by our Final Decision of the Access SCR?

If DNOs are required to adjust their baseline forecasts to reflect the behavioural impacts of the Access SCR proposals, then we would expect Ofgem to inform DNOs on what it believes the impacts are forecast to be, rather than each DNO producing its own forecasts. This will aid consistency in application of the impacts of the reforms and Ofgem's own confidence in what is presented in business plans. It will be necessary as part of Ofgem's process to predict any behavioural changes of consumers so as to assess policy options and select the optimal approach.

With regard to other impacts, it is very much dependent on the nature of the changes between the minded-to consultation and the final decision. If there are significant changes to the connection boundary proposals this would have the biggest impact and may require the financial aspects of the plan to be revisited as it could significantly affect cash-flow forecasts. In terms of the other aspects of the proposals, if the behavioural impacts are addressed through UMs, then the main impact is on the timing and cost of implementation. We would expect the final decision to contain very clear proposals on the implementation solution and timescales so that more thorough costs can be determined and reflected in the Final Business Plan submission.

8 Impact of COVID-19 on the price controls

Q34 Do you think we need specific mechanisms in RIIO-ED2 to manage the potential longer-term impacts of COVID-19? If yes, what might these mechanisms be?

A global event with the impact that COVID-19 has had is unprecedented. The timing of Gas and Transmission business plan submissions in December 2019 means that these plans won't have been able to reflect COVID-19 impacts.

In operating our ED business, at the time of this response in September 2020, we are still assessing the medium and longer-term implications of COVID-19. In the short term, through the COVID-19 restrictions, we have found through our agility, the commitment of our workforce and supply chain and by listening to stakeholders and customers that we have been able to continue to provide a high standard of service, throughout the period to date. We have also continued, in response to customer and stakeholder needs, to provide new connections where safe to do so as well as sustaining the delivery of our maintenance and resilience programmes of work. We took the view from the start of the COVID-19 restrictions that safety of employees and the public is paramount, but also our vital services would be even more critical, especially if COVID-19 impacts on our customers continues into the winter months.

Inevitably, whilst focussing on customer needs, the rapid changes we made to our business to ensure that vital services continued as seamlessly as possible have led to an increase in costs, for example, simple changes we've made, like how we now use both our existing company vehicles and staffs own cars paid company mileage so that staff going to fix power cuts don't travel together for extended periods. We have also been doing different mixes of maintenance work as certain jobs offer better ability to protect the public and our workforce social distancing compared to the most efficient, optimised programmes we would normally undertake. Under the RIIO-ED1 Totex Incentive Mechanism the increased costs are shared with customers and shareholders. At the scale these costs to date have been incurred to date we don't currently think action is needed by Ofgem in our current price control to address any shortfalls in allowances. It is too early to say even now what the enduring impacts might be on our costs and service levels. For example, it is unclear to what extent we will return to the, “old pre COVID-19 normal”. In our case, as an ED company, our separate process is running about 2 years later. So we expect to be able to more effectively assess and evidence the medium and longer-term impacts of COVID-19, if material enough on our business, and reflect these into our final business plan in December 2021. A decision on in period mechanisms may still need to be made based on the circumstances.

More widely, the working between Ofgem and network companies in response to the pandemic outbreak and subsequently towards supporting customers has been an exemplar of how regulation can work under the RIIO-1 framework. It is important that the overall package in RIIO-2 is mindful of the successes of RIIO-1 for customers and does not impede the decisive and customer focussed actions companies took to protect delivery of vital services, at additional cost, without recourse to Ofgem in advance. RIIO-2 might include no flexibility in the settlement for companies and is much more focussed on companies making cases to Ofgem for new customer and stakeholder requirements and if new risks come to pass. This could be a problematical way to work in the event of similar or repeat COVID-19 type situations in RIIO-2, as Ofgem may be required to take rapid and decisive action directly to enable companies to respond as they have in RIIO-1.

When Ofgem undertakes cost assessment, target setting and benchmarking it should carefully consider the 2020/21 fiscal year, and any subsequent COVID-19 affected year(s), if the situation is prolonged. Additionally, Ofgem should ensure that appropriate indices for changes to costs during the price control are reflective of network company cost changes. The energy networks sector provides essential services and has largely continued through the pandemic. Reference indices for costs might place too much weight on other sectors that have responded differently and have latent capacity in them due to COVID-19. We request Ofgem does not use an unrepresentative index influenced by sectors that have had a down turn and probably therefore won’t have the same cost pressures as energy networks. Additionally, ways of working might be altered that affect productivity levels now and the scope to drive future productivity improvements might be impacted. Indeed, the energy sector will likely see relatively more price pressures than much of the rest of the economy as the energy sector offers the opportunity to build back better, investing in infrastructure for long term societal and consumer benefit that commences work to address the decarbonisation challenge through a green recovery. Our stakeholder engagement on this consultation echoes this, with one stakeholder specifically stating that “*ENWL should focus on what it can do to enable and accelerate the Green Recovery.*” Therefore, general indexes and measures of cost are likely to diverge from energy sector costs due to the COVID-19 shocks different impact to each sector. To the extent that Ofgem agrees costs through uncertainty mechanisms during ED2, these cost submissions can take COVID-19 impacts into account as they are made, meaning that it is the base costs most susceptible to COVID-19 change that Ofgem and companies need to consider how best to do any necessary adjustments.