UK Power Networks' Response to Ofgem RIIO-ED2 Sector Specific Methodology Consultation

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Contents

UK POWER NETWORKS QUESTION SPECIFIC RESPONSES

QUESTIONS IN THE SSMC OVERVIEW DOCUMENT

1. Interlinkages and Competition and Markets Authority (CMA) Appeals in RIIO-2

OVQ1. 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 do not support this proposal as we believe the judgement of the CMA should be final. We are concerned that Ofgem's proposal could result in further delays and appeals and unduly impact delivery of the outputs and commitments in a shorter, five-year price control.

The RIIO-ED1 Competition and Markets Authority (CMA) appeals showed that under the updated appeals legislation in the energy sector, specific points could be appealed, with the CMA deciding on the individual points placed before it with Ofgem then required to implement the CMA's decision. As such, the policy proposed by Ofgem appears to represent a departure from the precedent set at the RIIO-ED1 appeals.

We note the correspondence between Ofgem and the CMA, where the CMA in their open letter suggest it has the ability to make an "in the round" decision even where the grounds of appeal are narrow[1]. If this is the case, we believe further consideration is required before seeking to introduce a post appeals review mechanism given the potential risk that it may appear to signal a deviation from implanting in whole, a decision of the CMA with respect to a successful appeal.

We believe recourse to the CMA process should be a last resort. However, if an appeal is triggered any decisions of the CMA ought to be applied as directed. We are wary of an un-ending process of litigation which we believe will not serve the interests of consumers or investors.

OVQ2. Do you have any views on the proposed pre-action correspondence, including on the proposed timing for sending such to Ofgem?

We are not supportive of any requirement to provide Ofgem with pre-action correspondence. If a licensee chooses to share correspondence with Ofgem in advance of lodging an appeal this should not be precluded, however, we do not believe Ofgem could, or should mandate such pre-action correspondence. All parties should be free to submit an appeal to the CMA, irrespective of whether they have engaged in pre-action correspondence with Ofgem.

[1] Open letter from Andrea Gomes da Silva, CMA to Jonathan Brealey, Ofgem, 30 October 2019.

2. Net Zero and Innovation

OVQ3. Do you agree with our proposed approach to a Net Zero re-opener?

On balance, given RIIO-ED2 is a 5-year price control we do not think that a Net Zero re-opener is needed. This is due to our concern that including a Net Zero re-opener in RIIO-ED2 could undermine efforts to accelerate decarbonisation by causing further delays in decision-making. We believe the Net Zero Advisory Group (NZAG), has sufficient time to influence RIIO-ED2, and that there is much higher confidence in the role that electricity distribution must play in facilitating low carbon technology in the 2020s, when compared with the Gas Distribution (GD) and Transmission (T) sectors. For example, the government has outlined how it will support low carbon electric heating and we have seen a strong signal that petrol and diesel car sales will end by 2035 at the latest – including hybrids.

We believe a combination of a Net Zero compliant common energy scenario with adequate ex-ante allowances and alongside automatic adjustment mechanisms will be sufficient to enable Distribution Network Operators (DNOs) to move quickly to changing customer and stakeholder needs. Provided the costs associated with the transition to Net Zero are adequately covered by other aspects of the regulatory framework, there may be merit in the Net Zero re-opener being a “back-stop” mechanism, with a higher materiality threshold for triggering. This could place a stronger incentive on utilising the suite of other uncertainty mechanisms, whilst retaining a more fundamental review option in reserve e.g. if there is a major change in government policy.

OVQ4. In what circumstances, would a centralised approach to setting forecasted outputs be appropriate? What form should this take?

A centralised approach using a common scenario is the right approach for dealing with the uncertainty associated with Net Zero. This is because it:

- Enables a clearer basis for benchmarking between DNOs and plans;
- Is consistent with national approaches to policy setting and can be more easily aligned with the plans of other sectors; and
- Helps to ensure a consistent approach between areas of the UK but allows for the introduction of regional variation where this is justified.

The common scenario should be the starting point. Developing and choosing an appropriate common, centralised, scenario will enable Ofgem to benchmark plans and therefore understand their efficiency.

Net Zero legislation is at UK level and Ofgem’s framework must ultimately align to this. If, as is likely, policy will be set primarily through central government or centralised regulation, then it will suit centralised forecasting. For example, central government is already taking action using a central approach in some areas such as the Clean Heat Grant. However, even if elements are delivered regionally, we think that it is still important to start from a common scenario and consider regional variations from that, where justified.

A common approach can also ensure consistency with the Electricity System Operators’ (ESOs’) Future Energy Scenarios. We have already done substantial work along with the other DNOs working through the ENA, using a building block approach, to develop the Distribution Future Energy Scenarios (DFES) using a common approach.

A centralised common scenario as part of the overall framework for the approach to planning for Net Zero is also consistent with a fundamental commonality across many aspects of the price control methodology, such as common outputs, common incentives and common measurement and reporting frameworks. It appears from the recent Draft Determinations that Ofgem appreciates the value of commonality and we urge as much commonality as possible within the RIIO-ED2 price control methodology.

The choice of whether to adopt a central or regional approach to forecasting should be considered alongside a decision about the approach to setting baseline allowances within the price control to achieve the forecast scenario. We have set below out the two sets of options we believe need to be considered with regards to scenarios and setting allowances.

Table 1: The pros and cons of using different planning scenario options in RIIO-ED2

Option	Pros	Cons
1. Centralised scenario that assumes no regional differences	• Enables benchmarking. • Aligned to National Grid ESO's Future Energy Scenarios (FES).	• Not reflective of actual uptake. • Could be a blocker to decarbonisation.
2. Centralised scenario that recognises regional differences	• Enables benchmarking. • Aligned to FES as a starting point. • Supports and enables local input to planning but is more flexible to different approaches.	• Complexity around joining up local and national plans.
3. Decentralised scenarios	• Supports local plans and encourages local actors to be ambitious.	• Lack of benchmarking. • Lack of confidence that regional bodies will be able to resource regional forecasts to the same level of robustness or at the same time.

Table 2: The pros and cons of setting allowances according to local and national decarbonisation targets

Option	Pros	Cons
A. Baseline allowances based on confidence of need with Ums ensuring Net Zero compliance	• In line with approach taken in other sectors. • Reduces impact of forecasting risks.	• Complexity around uncertainty mechanisms. • May not reflect local requirements.
B. Baseline allowances in line with Net Zero	• Ensures DNOs are funded to facilitate decarbonisation.	• Could lead to asset stranding and increases in bills.
C. Baseline allowances based on confidence of need with Ums enabling local and national targets	• Reduces impact of forecasting risks. • Supports local targets and action.	• Complexity around uncertainty mechanisms.

Our current view is that a combination of option 2 and option C above provides the best balance across a range of stakeholders. For all of the reasons above we consider the centralised common forecast approach to be the most suitable approach. A common centralised approach provides assurance that there will be a coherent nation-wide set of forecasts. The overall package needs to be fundamentally consistent with a Net Zero compliant central scenario but baseline allowances should have regard to the level of confidence at the time of determination and the package of uncertainty mechanisms must enable the achievement of regional targets. This approach requires an effective method to disaggregate central forecasts. This is something that we are working on via the ENA. It also needs all stakeholders to be confident about the operation of uncertainty mechanisms, which we discuss at OVQ3.

OVQ5. What would be the factors we should take into account that would give us high certainty in a centralised approach to setting outputs?

We have set out in OVQ4 the key factors which lead us to conclude that a centralised approach with scope for regional variation is the right one.

OVQ6. Alternatively, in what circumstances would it be more appropriate to take a decentralised approach to determining forecasts?

There should be a role for regional forecasts and regional variation in the roll-out of Net Zero policy investment and action. However, as we have shown in our response to OVQ4, for the DNOs, these should be used to justify

variations from a common central forecast rather than starting from different regional scenarios. Our key recommendation is therefore to include a common planning scenario that reflects regional variations and has alongside it uncertainty mechanisms that enables different areas to decarbonise at different speeds.

As part of the business plan process DNOs should identify local factors that could influence the speed of the transition and where there is robust evidence, such as funded policy commitments, then these should be included in the final business plan submission.

It is inevitable that there will be variation in how forecasting and planning is actually conducted because different bodies and different types of body will be involved in doing it. Prioritisation of work and resources devoted to it will materially impact both the robustness and timing of inputs. This suggests that relying solely on regional forecasting would not be appropriate. What is needed is the assurance that there is a consistently robust forecast in all regions and an ability to reflect different regional inputs where they are robust. This suggests a consistent way of evaluating regional forecasts is warranted. The weight that should be attached to such forecasts and plans ought to consider:

- The credibility of the evidence base that supports it;
- The methods by which that evidence has been gathered, for example the nature of any engagement programme involving local citizens, businesses and third sector organisations; and
- The priorities, resources and capabilities of local bodies.

We urge all parties to set expectations in relation to what constitutes good evidence and robust methods, while being sensitive to the different circumstances of such bodies. As we prepare our business plans, we are undertaking regional engagement with the same issues in mind. We are progressing with a major programme of engagement with our local stakeholders to explore with them the implications of our emerging DFES work and how regional perspectives could be factored in. The potential timing of local government bodies being ready and resourced to act should also be borne in mind. It is important that if these contributions are available in later years, DNOs should be in a position to facilitate these later developments as the RIIO-ED2 period progresses. Clarity on how uncertainty mechanisms would work to accommodate this is therefore important.

OVQ7. 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?

Confidence for Ofgem comes from having a robust central case with deviations from this based on clear evidence of decentralised variation. We have already highlighted in OVQ6 some of the factors that would increase the level of confidence in varying the central case. We repeat these here together with other factors to consider:

- Democratic mandate and extent of powers;
- Ability of authorities to generate own funding;
- Current levels of resource and the ability to ramp this up (major international cities have clearly been at the forefront of change perhaps due to being well resourced);
- The nature of the “value proposition” for customers and citizens considering who benefits from the outputs and whether it is appropriate for the burden of costs to fall on network customers;
- Local externalities which might enhance the case for action (for example, London has some of the most pressing air quality issues in Europe);
- The national significance of the particular region and national policy towards the regions. London is the obvious example but the government’s aim to “rebalance” the economy is relevant;
- Maturity of local supply chains for necessary goods and services e.g. solar PV; and
- Evidence that locations are experiencing change at different speeds.

OVQ8. 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?

The LEAP Best Practice guidance is helpful for regional bodies in formulating LAEPs, but remains High-level. Our practical experience of applying it in real life is that:

- Some elements of the guidance suggest methods which may not always be appropriate or practical. For example, through our engagement we are not confident that many local stakeholders will be in a position to produce building level demand models that looks at all the available technology options and captures interactions between energy vectors;

- There is typically a gap in technical expertise and resource for local authorities to meet requirements in time for inclusion in business plans, however, these bodies have ambitious targets and action plans are likely to mature over time; and
- COVID-19 has made engagement and progress on developing local plans more challenging. Whilst tackling climate change is a priority for many local authorities there is significant funding uncertainty.

Therefore, whilst the LAEP Best Practice provides good guidance, our experience to date is that the market is not mature enough to adopt it wholesale today. We recommend Ofgem considers this further and sets expectations that are achievable for all parties in the RIIO-ED2 period.

OVQ9. Which of the uncertainty mechanisms and incentives in Appendix 3 will be most effective in enabling efficient strategic investment?

A range of uncertainty mechanisms and incentives will be necessary in RIIO-ED2, and it is positive to see the Sector Specific Methodology Consultation (SSMC) reflects this. To ensure that electricity distribution networks enable decarbonisation at lowest cost and customers are protected from over-investment, uncertainty mechanisms can play a fundamental role.

Our view is that a combination of ex-ante allowances and uncertainty mechanisms should enable DNOs to ensure their interventions are well justified, timely and encourage system flexibility. To this end, the network utilisation strategy incentive and Low Carbon Technology (LCT) incentive should be looked as a combined incentive package that supplement the capacity volume driver.

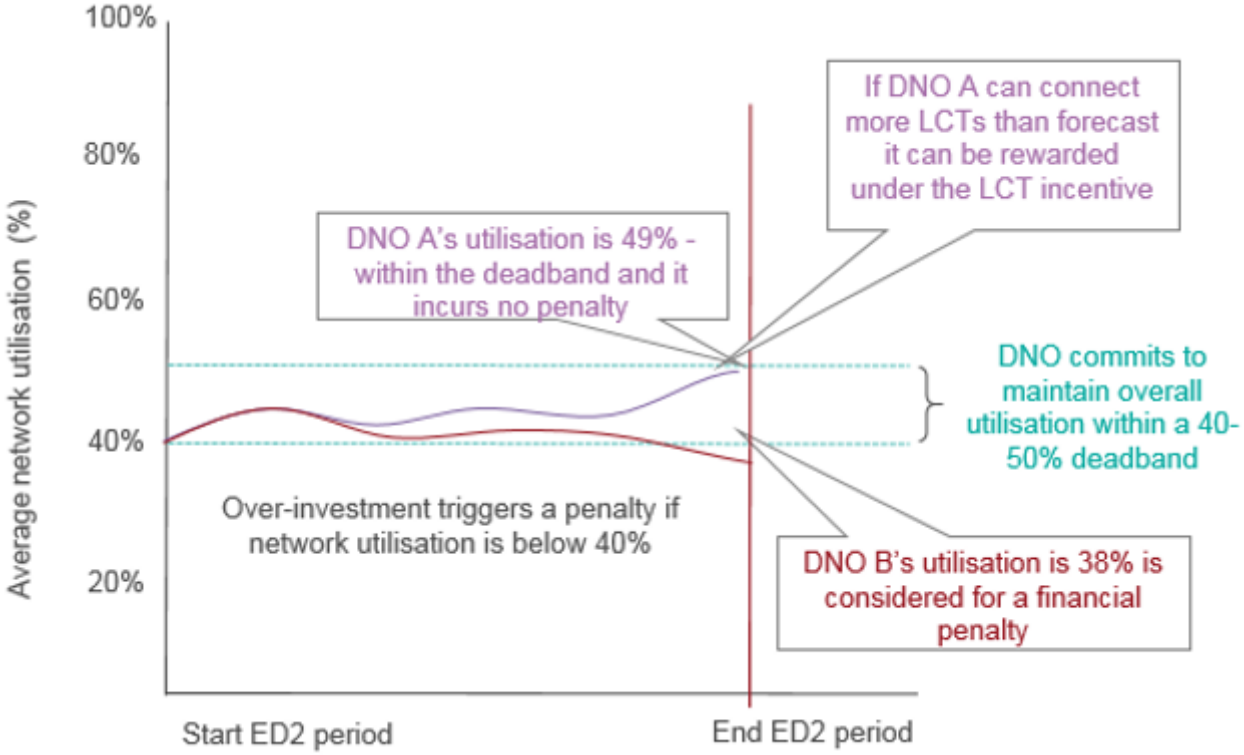
In Figure 1 we show how a DNO's utilisation target can be assessed and potentially be subject to a true up at close out according to a deadband. Our view is that a downside only utilisation strategy incentive holds DNOs to their commitments, thereby protecting customers from over-investment. However, the deadband would provide a level of protection in a similar way to the existing Load related capital expenditure (LRE) re-opener (±20%). In addition to this, there could be scope for allowing a DNO to submit mitigating evidence to Ofgem of factors outside their control, which caused utilisation to go outside of the deadband and the recent Covid-19 pandemic a case in point of an externality that could impact this mechanism.

As part of providing an upside element, we believe the number of LCTs connected versus the DNO's initial forecast should be considered. By the end of the period there should be robust data on LCTs connected, and again subject to a utilisation deadband, this can demonstrate if DNOs have connected what they forecasted to and have managed their network's utilisation levels efficiently. We recognise that the current LCT notification process is substandard and makes any metric based on LCTs challenging to implement at the start of the RIIO-ED2 period. However, we believe that DNOs and industry must address this issue as deployment increases to ensure timely interventions and no delays to future uptake. Including an ex-post LCT incentive will drive DNOs to both improve notification data and to connect LCTs where there is capacity headroom.

Whilst DNOs do not have material direct control on LCT uptake they do have control on their forecasts and how they manage utilisation, therefore this would provide a strong incentive for DNOs to submit accurate forecasts and help LCTs connect as cost efficiently as possible i.e. in places where capacity headroom exists where possible.

As the DNO is in control of their investment plan and utilisation strategy, we believe that this approach is compatible with one that futureproofs investments where appropriate, and could encompass the NIC recommendation regarding "touch it once". For example, if the marginal cost of a higher rated transformer is sufficiently low the DNO should be able to justify this in its business plan and projected utilisation level. Furthermore, through additional reporting of intervention costs these trade-offs will be revealed and reflected in future unit costs.

Figure 1: How a network utilisation strategy incentive and LCT incentive can work together



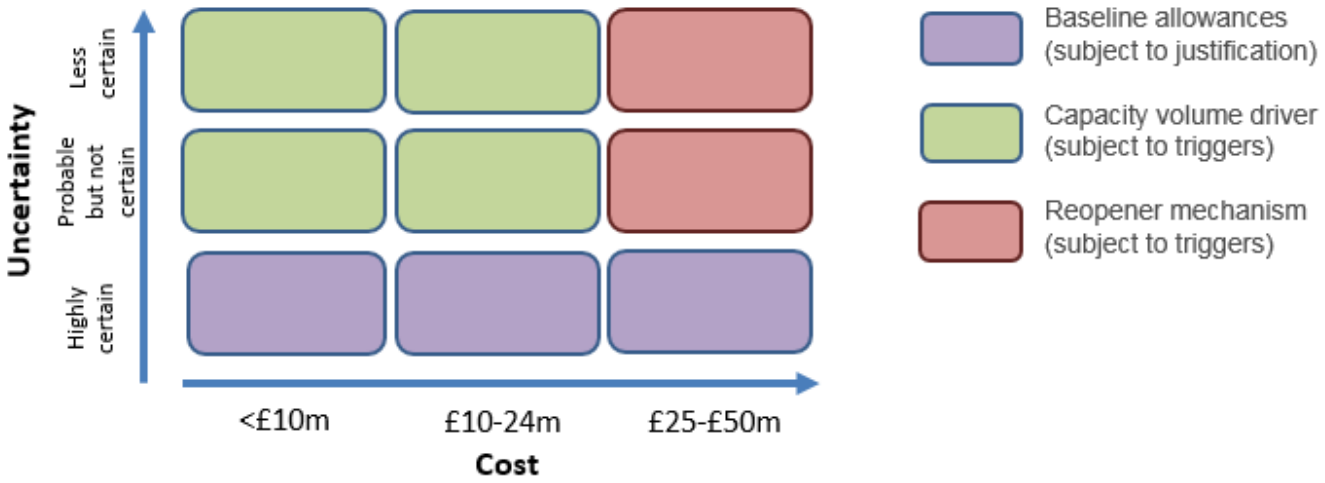
In addition to the above, Price Control Deliverables (PCDs) and re-openers will be more appropriate when requirements are more discrete, of higher value, and linked to locational requirements. However, where these are used Ofgem should expect DNOs to clearly describe where other mechanisms such as a volume driver interact to avoid any double counting. In most cases, due to the scale and nature of plans covered by PCDs, we do not believe that such interactions will cause an issue. Table 4 indicates where we believe different mechanisms best play a role in enabling strategic investment.

Following the government's recently announced package of new support for low carbon heat, which will target replacing fossil fuel heat in off-gas grid homes with heat pumps, we believe a PCD is the most appropriate mechanism for DNOs to deliver a programme of work to support this policy decision. Whilst we believe a combination of the Load Index and aforementioned capacity volume driver/utilisation incentive can cover most reinforcement requirements, given the strategic importance of electrifying heat off in grid gas areas, we believe confidence is high enough for DNOs to proactively release network capacity where criteria is met. There are significant benefits of targeting network upgrades in off-gas areas that typically will have high heat demand and yet are connected to weaker parts of the grid.

It is important that there is a common understanding of the role that different regulatory mechanisms play and how they work together. With regards to setting load related allowances, Figure 2 provides a high level view of how Ofgem's proposed mechanisms could be applied to different requirements depending on their cost and the level of confidence of need. For example, where there is uncertainty regarding forecasted demand changes the capacity volume driver can flex allowances subject to utilisation triggers in the majority of cases. Where projects are £25m+ i.e. of high value then these are likely to be better suited to specific triggers in a similar way to the High Value Project reopener in RIIO-ED1.

Whether low or high cost if there is a very high level of certainty that intervention is needed to meet requirements then the most appropriate mechanism is baseline allowances. Where some uncertainty exists, interventions are discrete and they meet a materiality threshold (currently £15m proposed), allowances should be set via a PCD. In other cases that are not captured by PCDs due to not meeting the materiality threshold, or the capacity volume driver, due to not being subject to utilisation triggers, then baseline allowances should cover requirements without an uncertainty mechanism. The unlooping of domestic services is a potential example of this.

Figure 2: How regulatory mechanisms can be applied to different areas depending on cost and level of confidence



Set out below we highlight key points to help guide how Ofgem may use the different mechanisms before providing a more detailed view on the strengths and weaknesses of each mechanism and on how they could apply for different types of expenditure:

- We believe that network utilisation has a critical role to play in both justifying expenditure and acting as a measure of how efficient expenditure has been. Utilisation is a key output measure that DNOs can react to that will help manage uncertainty around when and where new demand will increase on the electricity network and what interventions optimally manage this uptake. For example, if a cluster of EVs connect to a lowly utilised distribution substation the intervention costs will be significantly lower compared to if the same cluster connects to a distribution substation already running close to maximum capacity. We therefore welcome Ofgem's proposals around the network utilisation strategy and believe it would work in tandem with a capacity mechanism, particularly at the secondary network level.
- Due to time constraints and the considerable amount of work needed to implement these types of mechanisms into the RIIO-ED2 methodology we recommend Ofgem makes its decision on the options it will use by the end of 2020 at the latest. This will enable licensees, stakeholders and Ofgem to focus on finalising design parameters. Ultimately, this will ensure DNOs can submit accurate and ambitious business plans with knowledge of the triggers/thresholds for each mechanism, the data requirements, and deadband thresholds. We will continue to work with Ofgem, industry and stakeholders over the next few months to co-develop proposals as part of this.
- Table 3 compares and contrasts the proposed LCT volume driver and capacity volume driver in terms of their relative strengths and weaknesses. Based on our assessment the capacity volume driver has significantly more benefits than the LCT volume driver and therefore we are keen to work with Ofgem, industry and stakeholders to work this option up in more detail.

Table 3: Comparison of the two volume driver options in Ofgem's SSMC

LCT volume driver	Capacity volume driver
Ex-ante funding provided to meet a projected volume of LCT installations. The LCT volume driver would revise this allowance upwards or downwards at the end of RIIO-ED2 depending on the actual number of installations.	The capacity volume driver adjusts the DNOs allowance by a set unit cost (£/Mva) for each unit of capacity it releases. The capacity volume driver would revise this allowance upwards or downwards each year of RIIO-ED2 depending on the actual volume of capacity the DNO releases.
Strengths: • Allows DNO allowances to flex to needs with a relatively simple mechanism Weakness: • Current LCT notification process is substandard, therefore unclear it is how it would be implemented • Difficult to measure, particularly in-period when it would need to operate to release allowance • Unclear how it would enable DNOs to be proactive and ensure they are intervening ahead of connection requests unless ex-ante funding is sufficient • LCT volumes largely outside DNOs control, susceptible to external influences • Utilisation should be part of the mechanism to prevent windfall gains/losses as LCTs will not trigger any costs in areas of the network with spare capacity	Strengths: • Encourages LCT uptake • DNOs justify business plans against their network utilisation, providing a check on investment need • Allows DNO allowances to proactively flex to needs • Encourages better use of data to track asset performance • Automatic operation means avoidance of more reactive and disruptive re-openers • Clear set of historical unit cost data to set volume driver Weakness: • Requires robust data to set up and to track asset utilisation • Administrative burden greater, but should be outweighed by the benefits
Applicability: • Secondary reinforcement	Applicability: • Secondary reinforcement

A package of uncertainty mechanisms and incentives

Table 4 maps the suitability of each uncertainty mechanism and incentive to different types of DNO investment. There is some overlap between uncertainty mechanisms and incentives with different types of investment.

Table 4: Suitability of each uncertainty mechanism and incentive to different types of DNO investment

Type of investment	Price Control Deliverable	Capacity volume driver	Specific re-opener	Network utilisation & LCT incentive
Targeted, high value, strategic investment	✓		✓	
Primary reinforcement			✓	✓
Secondary reinforcement to electrify heat off-grid gas	✓			
Wider Secondary reinforcement		✓		✓
Enabling investments e.g. unlooping services	✓		✓	

OVQ10. Do you agree with our proposals to increase levels of BAU innovation?

We agree with the proposals to increase levels of BAU innovation.

Similar to the dynamics of a competitive market, DNOs should have a strong incentive to innovate to outperform. This is achieved through the TIM. Therefore, any adjustment to the Totex Incentive Mechanism (TIM) should not blunt the strength of incentives to seek new ways of doing things. TIM is a key driver that rewards DNOs similar to businesses operating in a competitive market. We consider that the proposed approach to setting the sharing factors for RIIO-ED2 risks providing a weaker incentive for BAU innovation than would be the case if sharing factors were higher. The TIM sharing factor allows DNOs to earn a return on successful BAU funded innovation while also allowing the risk to be shared. The strength of TIM sharing factors, therefore, directly influences the strength of the incentive for networks to take risks and innovate as BAU.

We agree that by now, DNOs should have embedded innovation culture into their BAU operations. Innovation funding has been available to DNOs since DPCR5 through the Innovation Funding Incentive. The evolution of the DNOs' innovation capabilities since then under the RIIO-1 Innovation Stimulus is clear to see through the sheer volume of innovation activities being carried forward and reported on through the Energy Networks Association (ENA) smarter networks portal[2]. An example of embedded innovation culture from within UK Power Networks includes innovation colleagues moving into BAU roles, funded by totex rather than dedicated innovation funding. Our view, therefore, is that the need for innovation stimulus in asset-based innovation could be reduced in RIIO-ED2.

Based on Ofgem's current proposals, we expect that most BAU innovation would target lower risk projects – higher Technological Readiness Level (TRL) ideas – which are more likely to translate into the realisation of in-period benefits for customers.

We support the Business Plan Incentive (BPI) as an incentive to innovation but would welcome greater clarity on how our Innovation Strategies and commitments are assessed against this incentive. Without strong incentives, innovation as part of BAU could be at risk of diminishing.

We note that price control mechanisms achieve greatest success when there are strong incentives. A clear example of this is the Interruptions Incentive Scheme (IIS) which has seen customer interruptions fall by 14% and the duration of interruptions reduced by 10% over ED1 so far[3].

We agree that Network Innovation Allowance (NIA) funded innovation should be focussed in areas where there is higher risk, such as whole system and facilitating Net Zero, or where the benefits do not directly accrue to networks such as customer vulnerability.

OVQ11. Do you agree with our proposed methodology in relation to the RIIO-2 Strategic Innovation Fund?

We support the proposals to enable access to innovation funding via the Strategic Innovation Fund (SIF) in areas where the financial rewards for successful innovation are less clear. We are happy with the broad scope. However, we would welcome further detail on the governance arrangements of the SIF as it becomes available. Consideration around the logistics of operating this fund should be considered, such as how funding is passed to third parties without leveraging a network operator licence. We would welcome working with Ofgem to resolve governance questions of this nature.

We would welcome close engagement with the Net Zero Innovation Board and would propose a member of the ENA has a representative on the board. This would enable us to better share our experiences of facilitating Net Zero, the strategic challenges we face and where we believe innovation can play a role. DNOs and the ENA already publish individual and industry Innovation Strategies. We would welcome information on how the Net Zero Innovation Board and Ofgem would factor in these strategies when deciding on the Innovation Challenges. This can help ensure the SIF aligns with the views of our stakeholders, who have spent considerable time feeding into the ENA innovation strategies over the past two years.

[2] https://www.smarternetworks.org/
[3] Ofgem RIIO-ED1 Annual report 2018-19, p.4.

We have interpreted that the frequency of the Innovation Challenges, which will drive the SIF, could be released on an “as and when” basis. It appears that the Net Zero Innovation Board will meet twice a year. We agree with the board meeting regularly as it reflects the need to frequently revisit the Innovation Challenges, however request Ofgem is mindful of the lead time it takes to arrive at a bid idea from reviewing an Innovation Challenge and to assembling a bid team, in most cases this can take 8-12 months. Furthermore, we appreciate there is no guarantee that an Innovation Challenge may materialise in a given year but equally there is no guarantee that there will not be an Innovation Challenge in a given year, which could potentially result in a “feast or famine” outcome. This can make long term resource planning more difficult and we propose either a planned frequency of challenges or a guaranteed maximum / minimum volume per year is shared.

OVQ12. Do you agree we should adopt a consistent NIA framework for DNOs, and other network companies and the ESO?

Yes, a consistent NIA framework for network companies and the ESO would support collaboration and allow unilateral comparison. We note that the ESO has a price control over two years, not five years. This may hinder collaboration due to the inability to partner with ESO on long duration NIA projects related to the energy system transition.

OVQ13. What are your thoughts on our proposals to strengthen the RIIO-ED2 NIA framework?

We welcome the proposals to strengthen the NIA framework.

We support the focus on using NIA for innovation around the energy system transition, Net Zero and customer vulnerability. However, we highlight a concern that low TRL research (such as industry funded PhDs) in other areas may reduce, as it does not have a direct value/return on investment within period due to a lower TRL.

We support more consistent reporting of innovation benefits. In RIIO-ED1, the benefits reporting from innovation as part of our annual E6 submission to Ofgem is an important metric, and justifies the use of customer money. At the end of regulatory year 2019/20, we have achieved £232 million worth of savings in RIIO-ED1 through innovation[4]. We welcome consistency in both scale and visibility across all licenced network operators with regards to the benefits the stimulus fund delivers.

Working with other networks, we have helped to shape and develop the Innovation Measurement Framework, being proposed by the ENA. It has been designed to provide a broader view of innovation, covering financial benefits delivered but also the wider impact of innovation activities. Including activities such as working with external parties and forming partnerships, the views of stakeholders of working with us on innovative projects and how effective we have been at rolling out innovation which has been developed by other DNOs.

We propose to use the framework, together with our stakeholders to set ourselves ambitious targets for innovation outputs in RIIO-ED2 to drive further improvement in our performance and allow our stakeholders to hold us to account. We would highlight that tracking and reporting innovation benefits is resource intensive and propose Ofgem confirms that the E6 return is replaced by the Innovation Measurement Framework being developed through the ENA.

OVQ14. Do you have any additional suggestions for quality assurance measures that we could introduce to ensure the robustness of RIIO-2 NIA projects?

The proposed ENA Innovation Measurement Framework[5] embeds a peer review into the reporting process. We believe this as an efficient and effective way both to provide challenge and ensure consistency in reporting, but also to share information around innovation projects. We do not see this peer review as additional burden, as UK Power Networks already reviews all other DNO project closedown reports.

Recognising that that were shortcomings in the NIA assurance measures during RIIO-1, the ENA, and the Network Operators it represents, are working through an improved way of NIA reporting for RIIO-2 on 1 April 2021. This takes the form of the Energy Networks Innovation Coordination and Assessment Protocol (ENICAP) – which will coordinate innovation activities before they are taken forward and so prevent duplication, improve reporting transparency on project costs and benefits.

[4] https://innovation.ukpowernetworks.co.uk/wp-content/uploads/2020/07/UKPN-NIA-Annual-Report-2020-FINAL.pdf
[5] https://www.ukeic.com/media/case-study-energy-networks-accelerate-the-uk-s-race-to-net-zero-carbon

OVQ15. Do you agree with our proposed approach for setting individual levels of NIA funding?

We agree that NIA innovation funding would naturally decrease as the scope for low TRL innovation projects decreases, and the proliferation of more BAU innovation as part of the totex allowance.

As noted in our response to question OVQ10, and in our response to the RIIO-ED2 Open Letter in Autumn 2019, there would be a reduced need for NIA (or SIF) funding if there is a high TIM sharing factor in place to allow DNOs to earn a return on successful BAU funded innovation and accept the associated risk.

However, in light of the proposal to review and potentially reduce the TIM sharing factor across the different cost categories, depending on the level of confidence in forecasts, we would anticipate a continued need for NIA funding to stimulate innovation in some areas.

We believe consideration should be given to the following when setting individual NIA allowances:

- Quality of the benefit reporting delivered in RIIO-ED1.
- The return on investment delivered in RIIO-ED1.
- The dissemination quality around innovation projects.
- Evidence of fast follow and BAU transition and roll-out.
- The volume of innovation solutions transferred into BAU.
- Robustness of existing innovation governance within the business.
- Delivery against RIIO-ED1 Innovation Strategies.
- The value the licensee commits to include as part of the BAU funded innovation.
- Level of collaboration and third party access delivered in ED1.

3. Modernising energy data

OVQ16. Do you agree with our approach to regulating digitalisation and better use of data through the introduction of cross-sector licence obligations?

We agree with Ofgem's proposals around publishing regular digitalisation action plans and defining requirements through cross sector licence obligations.

We are in the process of updating our Digitalisation Strategy and Action Plan, which will be published later this year. This will respond to feedback from both Ofgem and our stakeholders and will help frame our business plan.

Our view is that we need to be as agile as possible to continue to accommodate the transformational changes on our networks, whilst managing high-levels of uncertainty as to when and where changes will exactly happen. We therefore agree with Ofgem's iterative approach to continuously improve the use of data. As part of this DNOs should be given sufficient flexibility to respond to their stakeholders' needs in their business plans. Licence conditions should focus on ensuring minimum requirements and not be overly prescriptive on what the solution is and Ofgem should consider this risk when setting any new licence conditions, particularly those that will commence at the start of RIIO-ED2.

We believe a key focus in RIIO-ED2, which is different to other sectors, is the critical link between digitalisation and developing Distribution System Operator (DSO) arrangements that will save customers across GB billions of pounds. For example, to unlock the c.£17-40bn of benefits per year Imperial College estimate can be unlocked through local flexibility[6], DNOs need to invest in new monitoring and ICT capabilities to give better visibility of what is happening in local networks – this forms a central part of what the EDTF put forward in its recommendations[7]. We are encouraged by Ofgem's recognition that RIIO-ED2 should be more ambitious than GD2 and T2 with respect to modernising energy data. Digitalisation is not, nor should be viewed as a outcome in itself, it is there to deliver improved outcomes for customers and wider stakeholders. In order to raise the bar on what DNOs are doing in this space we are keen to co-develop with Ofgem a methodology that enables cost plans to be justified with respect to the benefits that can be realised and truly reflects the wider societal benefits that can be delivered by DNOs enabling this to happen.

Whilst in some cases we recognise that the time to deliver data related investments will be quicker than traditional physical infrastructure, we would flag that this is not always the case and that 'data' plans are often more complex and disruptive. By way of example, we have over 100,000 distribution substations on our network that we do not currently have any real time info on in terms of network loadings. Due to the growth of LCTs and flexibility agenda there will be a clear benefit case in some locations to getting this data, however, efficiently collecting, processing and sharing this level of data is not a trivial task. We consider it important therefore that any licence obligations take into account delivery timescales. This is needed to avoid putting DNOs at risk of being non-compliant as a result of not being able to meet unrealistic deadlines. Achieving this may require a flexible approach to entry in to force of new conditions.

We believe there needs to be consideration that the use of data and associated benefits are typically difficult to measure and subjective. For example, the measure of data quality is highly dependent on the intended use. When it comes to regulating, and by extension assessing and monitoring better use of data, the mechanisms by which this will done need to be carefully considered given this subjectivity. We urge Ofgem to avoid adopting licence conditions which are excessively prescriptive and rigid.

We will work proactively with Ofgem through the licence drafting working group to support development of requirements which promote better use of data in a suitably agile way.

[6] (2016) Carbon trust and Imperial College, An analysis of electricity system flexibility for Great Britain, p5 (available on line at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_analysis_of_electricity_flexibility_for_Great_Britain.pdf)

[7] https://es.catapult.org.uk/wp-content/uploads/2019/06/EDTF-Report-Appendix-1-Recommendation-Actions.pdf

4. DSO Transition

OVQ17. 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?

Yes, we agree, as this should give time to DNOs to establish the capabilities required. The DSO strategies provide the vehicle to evidence co-design with the market. Given that there is no established model in the world for this, enacting wide scale industry change needs evidence and robust justification. This would ensure that it does not detract from getting on with the job of electricity networks supporting the decarbonisation of the economy whilst ensuring high-levels of reliability.

We recognise that the effective functioning of flexibility markets relies upon all participants having confidence that decision-making is unbiased and based on network requirements. We are developing a RIIO-ED2 business plan based on developing DSO functions that will facilitate smarter more flexible networks that benefit consumers; we are getting on with delivering what customers have said they want. At the same time, the plans we are developing respond to industry feedback on how we can better manage perceived conflicts of interest and demonstrate transparency around our procurement processes and governance. Our business plan will detail our proposals and how we will use meaningful metrics to show progress. We believe that existing institutional arrangements provide sufficient scope for DNOs to respond to the issues Ofgem and industry have raised and therefore it would be premature to change these.

We are asking Ofgem to give DNOs the opportunity to deliver in line with expectations by confirming that only where all DNO fail to meet the requirements that the re-opener mechanism will be triggered i.e. it will be used as a "last resort". If one or more DNOs can successfully demonstrate that requirements can be met within the existing institutional arrangements, Ofgem should explore other mechanisms and avenues to bring laggards up to standard. The alternative would be unnecessarily imposing institutional change across the sector based on the underperformance of a sub-set of the involved parties.

We believe Ofgem could set out the criteria that would be used to assess the case for institutional change. The baseline expectations published in the consultation document provide a starting point but leave many aspects open to subjectivity – for example quality of data provision, clarity of dispatch rules set. We recommend clear objective criteria, which will be used to make any decision on separating out DSO functionality. The earlier these criteria are set out the more certainty it will provide to DNOs.

Ofgem could also give thought to the role that other uncertainty mechanisms can play in managing DSO related requirements. For example, the capacity volume driver alongside new PCDs can go a long way to ensuring that DNOs are appropriately funded to realising DSO capabilities.

OVQ18. 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 agree with the use of the Business Plan Incentive (BPI) to drive DSO ambition and reward companies with the best DSO strategies. But standards should only be required of all DNOs in the cases where they are genuinely applicable to all DNOs.

DNOs may not face the same challenges at the same time, and for this reason DSO capabilities and tools may look different between DNOs. It is therefore important the BPI strikes an appropriate balance between risk and reward for all DNOs. For this reason, we would only expect Ofgem to require all DNOs to adopt revealed standards in draft business plans where this is appropriate. The DSO Output Deliver Incentive (ODI) should be able to enable DNOs to define Key Performance Indicators (KPIs) and proposals that are both common and DNO specific as necessary, and this negates the need for a bespoke ODI. For example, areas such as DG curtailment could be common across DNOs but the actual targets will be dependent on DNO specific factors such as current network utilisation and volumes of connection requests.

The business case for the necessary DSO functionality will vary by DNO area depending on the penetration of Distributed Energy Resources (DER) and utilisation of each DNO's network at the start of RIIO-ED2. We have already seen that the impact of the 'solar boom' was not uniform across DNOs and each had to adjust at a different pace, with different tool sets. While future direction of the energy system transition is inherently uncertain, a similar

uneven pace of uptake of EVs and heat pumps in different DNO areas could well be expected. This will drive a different scale of DSO functionality across DNOs in the RIIO-ED2 period. Consequently, it would not be an efficient use of customers' money to drive all DNOs to reach the same level of capability and scope of DSO functionality at the same time. Ofgem will need to consider this when considering which DSO standards should be applied to all DNOs.

Notwithstanding the above points regarding DNOs having to move at different speeds due to network requirements and uptake volumes, we see a strong rationale for standardising DSO related products, access, data and procurement methodologies. By doing this, stakeholders will be able to engage much more easily, whether this is to self-serve their needs or offer up their flexibility to the wider system. To this end, significant progress has been made through the ENA's Open Networks project and DNOs are going in the right direction.

As part of Ofgem's updated Business Plan Guidance and Sector Specific Methodology Decision we welcome clarity on how Ofgem will delineate between minimum requirements that will be set in licence conditions e.g. on standard procurement procedures versus capabilities that link to specific distribution system requirements (such as new ICT to manage real-time flows in constrained networks). It would also be very helpful if Ofgem could provide guidance on how it will weigh up evidence from the DNO's stakeholders versus Ofgem's perceptions of what is needed when evaluating the Customer Value Proposition. This will minimise the risk that plans are misaligned with Ofgem's objectives and could be progressed through working groups.

OVQ19. Do you agree with our proposal to invite companies to provide metrics and performance benchmarks in their DSO strategies?

Yes, we support the proposal to allow companies to provide metrics and performance benchmarks in their DSO strategies.

These measures should include mechanistic annual performance measures, wherever possible, as opposed to be solely based on ex-post evaluation.

In keeping with the existing regulatory model, wherever feasible, performance should be measured and monitored annually across common KPIs that are seen as the most important in terms of demonstrating DSO capabilities. This would ensure that both Ofgem and stakeholders have clear visibility of whether DNOs are meeting their objectives and would form part of Ofgem's annual performance report. Ideally, setting these common DSO metrics should be the result of engagement between DNOs, Ofgem and industry. Subsequent to this, the DSO ODI and BPI would enable network companies to set ambitious targets under these common KPIs that also reflects local needs. Additionally, DNOs could appropriately develop their own KPIs to demonstrate progress on DSO capability, but these need not be applied to others.

As part of Ofgem's updated Business Plan Guidance and Sector Specific Methodology Decision clarity is welcome on which areas of DSO Ofgem are seeking consistency on versus those areas that Ofgem is willing to give DNO freedom to innovate and define on their own terms.

Ofgem should also clarify how they will delineate between DSO and their proposals on competition as currently this is unclear. Given that Ofgem's DSO roles will require and assess network companies' procurement methodology, we believe it would make sense for Ofgem to substantially consolidate their competition proposals.

We are strong proponents of the benefits of output-based regulation and consider there are number of successful precedents in past price controls that could translate well to DSOs. We provide a number of examples in our response to OVQ20 about the DSO ODI.

OVQ20. 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 Output Delivery Incentive (ODI).

In the response to this question, we highlight our concerns over the proposal for the incentive to be ex post. We have set out initial views on the benefits of mechanistic incentives and ideas on how these could be incorporated into the ODI. Finally, we have outlined a process to assess whether different ODI metrics should have a reward or

penalty and the role of the BPI in driving ambition on these metrics. We have dealt with each component of the question below:

1) Concerns over an ex post incentive

We do not think it is appropriate to evaluate performance under the DSO ODI solely on an ex post review. Our experience is that incentives which are more mechanistic and have annual targets are more effective in driving improved performance, as they allow comparison within the price control and time for companies to make changes to improve performance and deliver benefits to customers in a timely fashion. The IIS and BmoCS Output Delivery Incentives (ODIs) are examples of where regular performance reporting alongside incentivisation has resulted in significant improvements. For example, since 2010 DNOs have reduced the number of customer interruptions by 36% and reduced the duration of customer interruptions by 46%.

Ideally, performance would be measured and monitored annually across common KPIs that are seen as the most important in terms of demonstrating DSO capabilities i.e. linked to baseline requirements. There is a strong track record of using mechanistic incentives, with performance benchmarked across DNOs, to deliver improved service to customers and report to stakeholders on that performance annually.

A clear advantage of having six DNOs assuming new DSO roles is the ability to incentivise performance, benchmark companies, learn from the best performing DNOs and raise all other DNOs up to that standard. We can see significant customer benefits in this approach, given that these are roles are new with little experience or evidence on how best to deliver them.

In contrast, an ODI based solely on an ESO style ex post incentive, has a number of drawbacks:

- It reduces the scope for DNOs to learn from each other on best practice during RIIO-ED2;
- The timing of an ex post review means that it is not possible to embed learning from an ex post review into RIIO-ED3 outputs and incentives (delaying the adoption of best practice across all DNOs); and
- It does not provide clear expectations on performance and baseline expectations leave significant room for interpretation of what “good” looks like. For example, outputs in RIIO-ED1 such as IIS and BMoCS are much more transparent and objective than the ESO’s current list of outputs; and
- It risks a shift to a weaker regulatory mechanism and creating disruption at a critical time for industry; whereas evolving existing arrangements e.g. by including new in-period KPIs will drive competition and spur continuous improvement.

2) The role of mechanistic incentives for the DSO ODI

While we recognise that Ofgem wants to reduce its administrative burden, we do believe that it is in customers’ interests to have regular performance monitoring on outputs that have the greatest value. To find the right balance we would welcome Ofgem working with the DNOs and interested stakeholders to arrive at a set of common KPIs that link to DSO functions. Our view is that there could be a number of metrics with different financial weightings which can combine under the DSO ODI (similar to components under the Broad Measure of Customer Satisfaction). Below we have set out a few examples of what these could be and would welcome further discussion on this subject with Ofgem, other DNOs and broader stakeholders:

- **A common stakeholder survey:** Many of the baseline expectations cover providing data to customers in the granularity, timeframe and format that they need; or the processes put in place with Local Authorities, the ESO and other network operators to facilitate whole system planning and operation. These aspects are well suited to targeted stakeholder surveys which can be run annually (based on a common questionnaire) to help stakeholders to identify and shape best practice across DNOs.
- **Forecasting accuracy of network outages for DG and storage:** Ofgem’s baseline expectations include the provision of information around outages or DG and storage customers on the network. We consider it would be helpful to track the accuracy of those forecasts and report against them. This would incentivise DNOs to improve the accuracy of information and subsequently the confidence that customers had in the forecasts.
- **The percentage of network that has accessible and up to date utilisation data: A** key part of baseline expectations is the provision of network data to inform flexibility markets. This will primarily be based on information around network utilisation. Consequently, an important metric could be performance against a target proportion of the network which has accurate information on network utilisation (based around smart metering data and specific monitoring equipment).

- **A set of common commitments around openness and transparency:** Many of the baseline expectations cover the procedures and processes which DNOs have in place to ensure a transparent and neutral assessment of network options for planning and operations. DNOs could make a set of common commitments on how to deliver this and report progress against these commitments each year (against a plan of actions). This would provide clarity to stakeholders on how DNOs planned to deliver against the objectives set out in baseline expectations, track progress against the plan and hold DNOs to account where they fail to deliver.
- **Network utilisation levels with respect to demand outturn:** We support Ofgem's proposal around using network utilisation as a metric to track the efficiency of investment. We anticipate that this will adopted as part of a core incentive but if not, we consider it would be a useful metric to fall under the DSO ODI.

We recognise that work needs to be done to develop these further and how they combine into a single DSO ODI. However, this work will help establish benchmarks for what "good" performance looks like. It is essential that benchmarks for what is "good" are clear and established as soon as possible so that DNOs can plan accordingly.

3) Process to help set rewards and penalties

We agree with Ofgem that the DSO ODI needs to take account of what activities are already incentivised under the TIM or other existing incentives. We see the respective roles of the various incentives as follows:

- **Business plan incentive**: This should recognise the level of ambition around DSO and reward DNOs who can propose well thought through metrics which can be applied on a common basis across all DNOs. It should also recognise where DNOs are proposing to go beyond baseline expectations and the quality of justification around these proposals. We welcome greater transparency in advance of Business Plan submission on the assessment framework Ofgem intends to use for evaluating company performance in this area and seek clarity from Ofgem on its scoring in their business plan guidance and the sector specific methodology decision by the end of 2020 at the latest. Providing clarity on this topic in the draft or final determinations, leaves it too late for DNOs to react on a fundamentally important topic for ED2.
- **Totex incentive**: This should drive DNOs to undertake DSO activities which help to reduce overall costs or improve performance against existing incentives. We note that there are some baseline expectations such as considering smart solutions or solutions proposed by other network operators which may already be adequately incentivised under the totex incentive. Further rewards or penalties for these under the DSO ODI may not be required.
- **DSO ODI**: This should perform three functions. First, it should hold DNOs to account on delivering the minimum requirements. For example, by tracking delivery of commitments to meet minimum requirements. Where these aren't delivered, we believe that penalties would be appropriate. Second, it should reward performance which goes beyond the baseline. This could be particularly relevant to the quality and accessibility of planning, operation and market information, rewarding DNOs who establish best practice. Third, the DSO ODI needs to provide an incentive in areas where DNO activities can deliver wider system benefits (see the response to OVQ22 for a view of the quantum of these benefits). For example, the quality of forecasting information around network outages for DG and storage or the quality of engagement with the ESO to deliver whole system benefits. Stronger rewards may be required in these areas.

OVQ21. Do you agree with our proposal to undertake that ex post inventive performance assessment in the middle and at the end of the price control? Do you think the assessment should be more or less regular?

As highlighted in our response to OVQ20, we consider that the more regular the assessment, the better and that the DSO ODI should have some metrics which are reported annually.

It is in the interests of customers that performance appraisal is timely and DNOs have clear output measures. Ex-post mechanisms have well documented challenges. For example, if Ofgem chose to only review performance at RIIO-ED2 closeout there would be a big danger that performance in the first years of RIIO-ED2 would not be adequately tracked, which will be negative for both DNOs and their customers in terms of being able to measure and respond to feedback.

OVQ22. Do you have views on how we might set appropriate values for rewards and penalties associated with the DSO ODI?

As highlighted in our response to OVQ20, Ofgem has a unique opportunity to use strong incentives and benchmarking of performance to rapidly drive up the quality of DSO service levels, which can deliver benefits across the energy system and help to facilitate decarbonisation. This approach has never been possible for the ESO (being a single system operator). DNOs have a strong track record of delivering against incentives and raising the levels of service which customers receive, across reliability, customer satisfaction and connections. Consequently, we are concerned that simply replicating the structure and approach used to value the ESO incentive scheme may miss an opportunity.

This is a crucial area where the framework put in place for RIIO-ED2 will define the DSO performance for the next 10 years (a critical time in meeting decarbonisation targets). We consider that further work is needed by Ofgem and DNOs to scope out appropriate values for the DSO ODI and we are keen to work with Ofgem and broader stakeholders to do this. Below we have set out the elements which we consider Ofgem should consider when assessing the value of the DSO ODI (or constituent aspects of the DSO ODI).

1) What value can DSO actions can deliver?

Arguably, the biggest driver of value from DSO is optimising the level of investment in the distribution system to deliver Net Zero at lowest cost. Without DSO related actions, the convention would be to build a large network to cater for short periods of peaks in demand and generation. DSO value is therefore the delta between a traditional network solution and the other options that the DNO can deploy to produce the same outcome with greater efficiency. It follows that DNOs should be incentivised to find these efficiencies and it is appropriate that both DNOs and their customers share the benefits associated with realising the delta.

2) Assess whether DNO has been funded to deliver this level of service/performance

Incentives should only be used to reward performance which goes beyond that which the DNO has been funded to deliver. For the DSO ODI, we consider that DNOs should be funded to meet Ofgem's DSO baseline expectations, rewarded where they exceed them and penalised where they fail to meet them. This undermines the importance of understanding what baseline expectations mean in practice, in order for DNOs to build and cost a plan to deliver them (see response to OVQ23 below).

3) Assess if the DNO is already incentivised to deliver the level of performance

We agree with Ofgem that the DSO ODI should only be used to reward areas where DNOs do not already have an incentive to deliver. Ahead of the Sector Specific Methodology Decision we are keen to further discuss where the gaps are in incentives and how the DSO ODI can augment existing mechanisms – we have initial thoughts on this.

We are concerned by Ofgem's proposal that the DSO ODI should be more downside than upside. A number of studies have illustrated that a significant proportion of the benefits delivered by the DSO fall elsewhere on the energy system[8]. The chart below is taken from the ENA's Future World Impact Assessment and highlights the different categories of benefits from optimum use of flexible DER out to 2050.

[8] Carbon Trust and Imperial College London, An analysis of electricity system flexibility for Great Britain, November 2017 – available online at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_analysis_of_electricity_flexibility_for_Great_Britain.pdf and the ENA Future World Impact Assessment: https://www.energynetworks.org/assets/files/Future%20World%20Impact%20Assessment%20report%20v1.0_pdf.pdf

Figure 3: Overall net benefits across the electricity system of using distribution-based flexibility under the ESO's Community Renewables scenario as published in 2019[9]

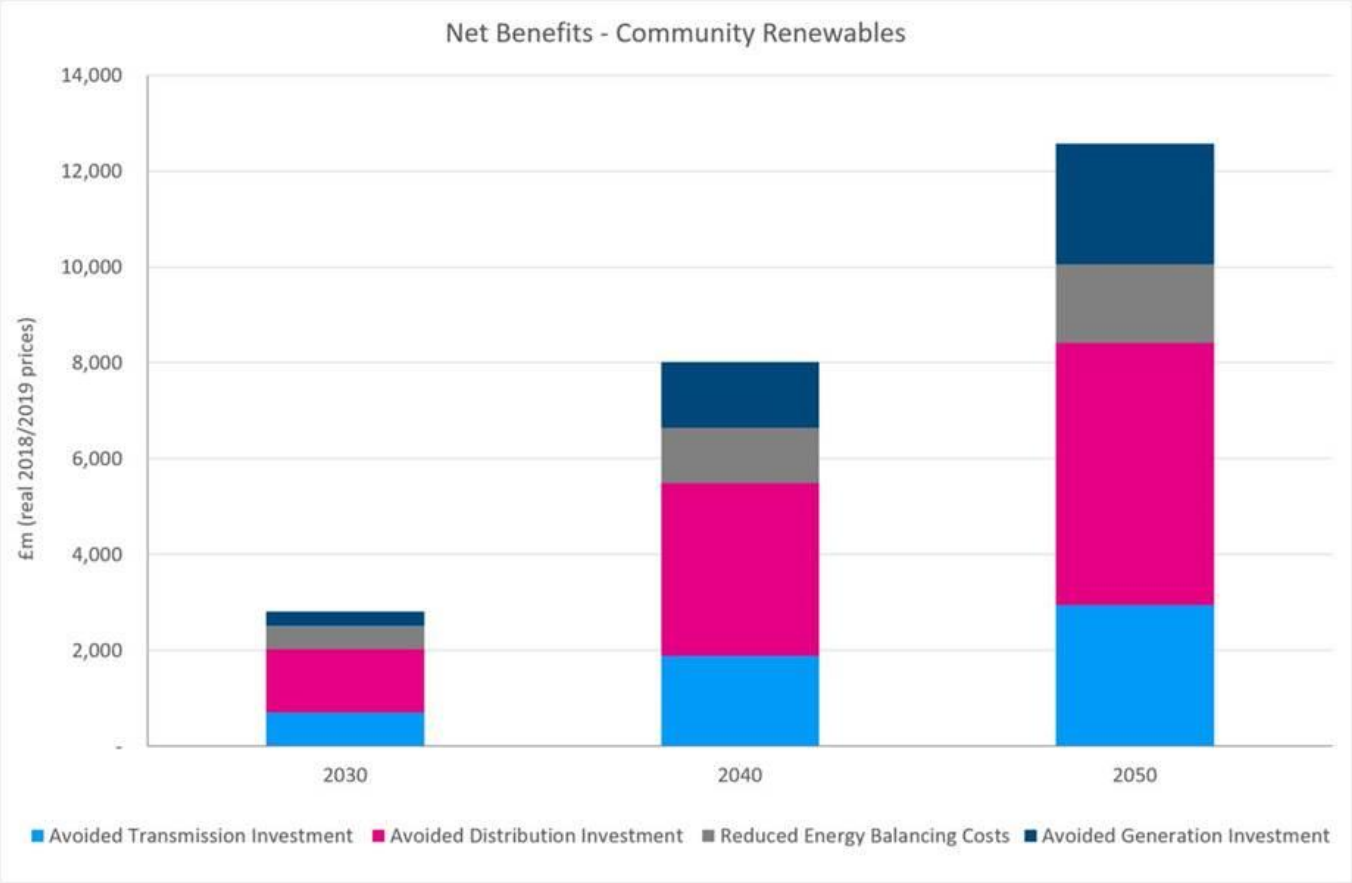


Figure 3 highlights four categories of benefits. Of these four, DNOs are only incentivised to deliver avoided Distribution Investment. Even for this category the totex incentive only covers investment which falls under allowed revenue as opposed to connections (unless there is a change in the connection boundary) and where that avoided investment is within a regulatory period. The DSO ODI could look to capture these wider benefit categories as well as the longer-term value streams and indirect benefits that can be clearly attributed to DNO actions. In addition to these categories, the DSO ODI could also cover the carbon emissions associated with planning and operating the distributing system could be reflected in the DSO ODI to ensure that DNOs take a proactive role in managing emissions within their control.

DNOs have no incentive to deliver the benefits in the other categories. While the DSO baseline expectation can help DNOs to be funded to deliver some of these benefits, incentives which push DNOs to beyond baseline can reveal best practice and deliver greater benefits to energy customers. We believe there is a case to be made for mechanistic incentives to factor in these wider costs and benefits when they are not already monetised elsewhere. A strong upside reward under the DSO ODI is crucial in ensuring DSOs can make the business case to invest in the capabilities to deliver these benefits.

4) Levels of confidence in setting targets

The value of the incentive should take account of the level of confidence which Ofgem, DNOs and stakeholders have in setting and reporting against targets. Where there is limited or low-quality historical data on DNO performance it may be appropriate to set tighter caps and collars for incentives than in areas with a robust set of performance data spanning a number of years. For example, since the start of RIIO-ED1 we have been developing flexibility markets and to date we have procured over 300MW of flexibility. Therefore, this is an area that we have gained evidence on that will inform future targets and cost savings. We would encourage Ofgem to use the RIIO-ED2 period to build up further data to gradually increase confidence in target setting for RIIO-ED3.

[9] https://www.energynetworks.org/industry-hub/resource-library/open-networks-2019-ws3-impact-assessment-on-future-dso-worlds-(benefits).xlsx

OVQ23. 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?

In the response to this question, we have set out our views on the next steps required on the baseline expectations to ensure they provide the basis for objective assessment of DNOs delivery of DSO functions; we have outlined areas were we believe amendments may be required and finally highlighted the implications for cost reporting against baseline expectations.

Views on how to build on baseline expectations

We welcome the fact that Ofgem has published the baseline expectations and they align with the work that we are already progressing and implementing in RIIO-ED1. As a set of guidelines around the scope of roles and activities covered by the DSO, we consider they provide helpful clarity. However, they don't at this point represent a set of clear requirements and outputs which DNOs can be objectively assessed against. This objective assessment is critical if any decision around DSO separation is to be based around delivery of the baseline expectations.

To help work towards providing the clarity needed, we have outlined below different categories which the various baseline expectations fall into and our views on the further work required (by DNOs and/or Ofgem):

- **Requirements around data provision:** Many of the baseline expectations set out what type of data should be shared e.g. asset data, heat maps, operational data, outage planning data. There is work for each DNO to do to engage with its stakeholders and propose the details of how they will build on existing processes to provide this data in the formats which stakeholders want. However, in this area it is difficult to assess what will constitute baseline requirements vs going above baseline in these areas and each DNO may take a different view on this depending on its feedback from stakeholders. Consequently, we consider that there is merit in common engagement between Ofgem, DNOs and stakeholders to inform what baseline requirements in this area look like. Establishing this clearer baseline will allow Ofgem to better compare the costs of meeting baseline expectations around data provision, across DNOs (as they will all be costing to meet the same requirements). It will also enable DNOs to be clear on where they plan to exceed baseline expectations and to provide evidence to justify the additional proposed expenditure.
- **Transparent assessment of network options:** The baseline expectations set out the objective of transparent and neutral decision making by DNOs around network options (in both planning and operational timescales) e.g. transparent dispatch process, avoiding conflicting uses of flexibility. However, there is further work to do around the detail of how these objectives will be delivered. We consider DNOs should consider this and develop a plan on how to deliver against these objectives as part of business plans. This will provide some tangible actions which can be linked to performance under the DSO ODI;
- **Prescriptive descriptions of DSOs roles**: Under Role 2 – Network Operation, a couple of the baseline expectations are focussed around ensuring open Application Programming Interface (APIs) for dispatch infrastructure and highlighting that network operations and system architecture should not be "hard coded" so that only DNOs can perform these functions in the future. While we understand the sentiment behind some of these requirements, we are concerned that by starting to go into detail about APIs and system architecture, it leaves some open questions over what this looks like in practice and could be open to a range of interpretations. Equally, some of the wording around the DSOs' role in co-ordinating markets to drive benefits to consumers, maybe overly restrictive (see A5.18 of the SSMC overview). For instance, in our Power Potential innovation project with the ESO, we are exploring how DER can contract with the DNO and provide services to both ourselves and the ESO. This is an important pillar of our plans for whole system co-ordination. Consequently, we think that it would be helpful to test some real world examples against Ofgem's intended sentiment to flush out how the requirements could be made clearer.

Linked to the point above, we are conscious that the SSMC document is the first time that DNOs and stakeholders will have seen the detail of baseline expectations. To avoid any misunderstanding of the baseline expectations, we believe there would be merit in a workshop(s) led by Ofgem with document outputs. The workshop(s) would review the baseline expectations under each role and ensure that all DNOs and stakeholders interpret them in the same way. This will help identify where further detail or clarification is needed and allow us to test real world examples against the baseline expectations. We consider that this will identify any issues and allow a clearer set of baseline expectations to emerge, which have a common understanding across DNOs and stakeholders.

Amendments to baseline expectations

We are conscious that the Access SCR could have a significant impact on the role of the DSO, in particular the volume of actions it has to take and subsequent scale of functionality and data provision. We suggest that the baseline expectations are reviewed once the Access SCR is finalised to check if there need to be any changes.

We also found that many of the baseline expectations under Role 3 – Market Development overlapped with the data provision required under Roles 1 and 2. It may be possible to consolidate some of these expectations. Consolidation would make tracking performance easier and reduce the scope for misinterpretation across separate baseline expectations covering similar areas.

It is important that risks are placed on the parties best able to manage them. In addition, for that reason it may be useful to keep options open as markets mature. This is especially the case in areas where DNOs are actively examining such as the application of time of use price signals via Distribution Use of System (DUoS), direct procurement of flexibility and offering non-firm access.

How to report costs associated with baseline requirements

We agree with how Ofgem has presented the DSO roles under the baseline expectations, as it emphasises the incremental nature of the activities compared to activities DNOs are already developing across the three DSO roles. However, given Ofgem's intention to capture DSO costs separately in the Business Plan Data Templates (BPDT), we can see that it will create significant complexities for cost reporting within the BPDT. For example, if we have to report all costs covered under the DSO roles separately, we will need to report the costs of dispatch activities within our control room, separately from the costs of taking decisions around traditional responses to network faults. This may be the same people undertaking different assessments as part of their day-to-day role.

We are actively working with Ofgem and other DNOs in this area and can see a significant task ahead of delineating costs between DNO and DSO and mapping to the DSO roles. We consider that this task could be easier if Ofgem was clearer around the DSO roles which may be subject to separation. Role 3 – Market Development is a clear distinct role and the process of highlighting costs associated with role, would be much easier to report separately. This would also set out a clearer scope for any separation of DSO functions in RIIO-ED2, helping to reduce our business risk (as highlighted in OVQ17). We will continue to work with Ofgem and DNOs in progressing these issues through the BPDT working group.

5. A Whole system approach

OVQ24. Are there any electricity distribution specific barriers to whole system solutions, and if so, are there any sector specific price control mechanisms to address these?

We do not consider that there are any electricity distribution specific barriers to whole system solutions. However, deploying whole system solutions is particularly relevant for DNOs in facilitating decarbonisation. As such, we think there is scope for Ofgem to develop RIIO-ED2 sector specific price control mechanisms for whole system solutions.

We have made significant progress on developing whole system solutions in RIIO-ED1. One example of this is the work progressed through our Regional Development Programme with the ESO on contractual elements, which support transmission constraint management requirements and N-3 protection system through our control system[10].

Whilst there are numerous other examples like this that are as a result of the significant changes happening on our networks, there is a lack of mechanism in place to fund and recognise the value of this work. As efforts on whole systems ramp up we believe it would be pragmatic for Ofgem to ensure regulatory mechanisms exist that enable DNOs to help offset other networks' costs. We see this as a way of evolving from a focus on innovation trials to embedding whole systems into BaU.

More specifically, we do not think there are sufficient incentives on network companies to invest the considerable time and effort require to deliver an efficient and co-ordinated whole system planning process. The actions DNOs take in facilitating decarbonisation through electrification of heat and transport, connecting DER and through the use flexibility can offset costs to the wider system. As highlighted in our response to OVQ22, this can provide substantial whole of system benefits across the RIIO-ED2 period and beyond.

As Ofgem has confirmed that the ESO will not be directly involved in the Coordinated Adjustment Mechanism (CAM) because they do not have totex allowances in the same way as other licensees, we believe that there is a gap Ofgem needs to address in terms of enabling the ESO and DNOs to transfer outputs and work collaboratively. For example, the DNO can take actions that will reduce Balancing Services Use of System (BSUoS) (balancing costs) the ESO administers and vice-versa, but there is a lack of funding mechanism to drive this. Whilst we are aware that commercial routes (Directly Remunerable Services (DRS) via commercial ancillary services) are being used, we welcome clarity from Ofgem on whether they see this as an enduring way of delivering whole system services.

Consequently, we consider that facilitating whole system solutions could be part of the DSO ODI with DNOs rewarded where they either deliver benefits, or facilitate whole system solutions for other network sectors. Without this, we are concerned that the CAM, as is currently proposed, may provide insufficient incentive on network companies to voluntarily transfer funding and outputs to pass them onto another network company to deliver.

OVQ25. Are there any electricity distribution specific issues you think should be accounted for in the Business Plan Incentive?

We have not identified, at this stage, any electricity distribution specific issues (beyond the points we make in our response to OVQ24). However, we are concerned that Ofgem is seeking to set a higher bar for DNOs in this area than it applied in the GD2 and T2 draft determination – but without providing additional guidance on its expectations or the assessment criteria it will apply.

We fully support cross-sector engagement and we are going to great lengths to ensure that we listen and respond to feedback from other network licensees. We recognise that our business plans will have implications beyond our networks, therefore it is incumbent on us to demonstrate how we have factored these in e.g. to find efficiencies through joint programmes of work.

As Ofgem has not proposed anything in RIIO-ED2 on whole systems differently to what was decided for RIIO-GD2 & RIIO-T2 we believe that the assessment process should be aligned i.e. expectations should be at the same level. Regarding Ofgem's statement that "DNOs are particularly well placed to move swiftly with solutions. As such, we expect to see a high-level of cooperation, ambition, and collaboration in their Business Plans.", we are concerned that Ofgem is setting a higher bar in RIIO-ED2 without having put in place any guidance or mechanisms to facilitate

[10] https://innovation.ukpowernetworks.co.uk/projects/power-potential/

this. This builds on our response to OVQ24 and reflects the fact that there is a lack of clarity on how DNOs would be funded for delivering benefits outside of their domain.

OVQ26. Do you agree that whole system solutions are relevant to the innovation stimulus?

Yes, we agree that whole system solutions are relevant to the innovation stimulus. It is an example of an area where DNOs receive little return for successful innovation (through the current package of incentives) and therefore it is appropriate to use dedicated funding to help develop capability and solutions in this area.

OVQ27. Do you agree with our key proposals for the CAM?

UK Power Networks supports the concept of a Coordinated Adjustment Mechanism (CAM) as a way to ensure that outputs and associated funding can be transferred to the most efficient delivery body. The totex incentive mechanism, uncertainty mechanisms (including appropriately calibrated volume drivers) and a clearly defined BPI should be the primary levers for ensuring that licensees have appropriate outputs. However, in addition to these we agree with Ofgem that the CAM can help address:

- the different timings of the electricity distribution price control from other sectors; and
- unexpected changes in circumstance and/or information

Whilst we fully support the principle behind the CAM, we do have some reservations on whether the CAM's proposed design will provide a strong enough driver for network businesses to put it to use.

We currently struggle to see a strong rationale for licensees to transfer away their outputs and allowances in a way that will meet their needs and those of the other licensee involved in the transfer. We are also concerned that this could take time and effort to implement and end up not being used by network companies.

We will continue to engage with other network licensees and the ESO to explore where whole system solutions can provide benefits and are fully open to using the CAM where feasible. However, our view is that the Directly Remunerable Services (DRS) will remain the primary mechanism for licensees to work together to deliver whole of system benefits.We disagree with Ofgem's proposal to not have a materiality threshold as part of using the CAM. In line with the High Value Projects (HVP) re-opener, the CAM should have a minimum materiality threshold of £25m and be applied per individual scheme. We note that in its Sector Specific Methodology Decision (SSMD) for the gas and transmission sectors Ofgem set a £50m threshold value for 'early' competition and £100m for 'late' competition based its internal modelling. Ofgem may therefore want to consider justifying why the CAM threshold is lower than these other thresholds that have been consulted on.

When setting the materiality threshold Ofgem should ensure that the CAM drives a level of effort commensurate to the potential benefits it brings and that licensees do not undertake unnecessary work. By way of example DNOs currently charge Assessment & Design (A&D) costs when providing connection offers to customers. This includes the cost of staff wages, undertaking surveys and site visits amongst other things. To summarise, failure to have a materiality threshold for the CAM would risk driving additional costs to licensees to investigate proposals that do not offer sufficient value to the licensee and its customers.

Further to the above, we believe Ofgem should make clear what type of expenditure the CAM will cover, as we do not see it covering all expenditure. For example, we do not envisage the CAM dealing with expenditure relating to condition-based asset replacement of High Voltage (HV) assets. In line with the CAM being in place to manage unforeseen circumstances, which could involve higher than forecasted DER growth due to policy changes, we recommend that the CAM be tied to outputs and allowances covering the following areas:

- Reinforcement;
- Fault level management;
- Reactive power; and
- Voltage management.

OVQ28. Do you consider that two application windows, or annual application windows, are more appropriate, and should these be in January or May?

Our initial position is that the May deadline is more appropriate as this is line with previous windows and would give more time for the CAM to be used as intended. As well as shortening the re-opener window, the January deadline

has the issue of requiring work to be carried out over the period just before Christmas, which is often impacted by external weather events and is a popular time of the year for staff to take leave.

Due to the later start of RIIO-ED2 relative to RIIO-T2 and RIIO-GD2, we agree that only a single in-period re-opener window should apply for DNOs in 2025, which would follow the 2023 re-opener window (for T2 and GD2) that coincides with RIIO-ED2 business plan submission.

We do not support inclusion of any additional re-opener windows due to the increased regulatory burden these would cause on licensees, as well as the significant administrative and budgetary pressures it would place on Ofgem itself.

OVQ29. Do you consider that the current electricity distribution licences should be amended to include the CAM, or wait until in 2023 at the start of their next price control?

We do not consider that there is a need to amend electricity distribution licences ahead of 2023. We are open to working with other licensees in developing whole system solutions in the remaining years of RIIO-ED1 and believe that these can be facilitated through the existing DRS licence condition or brought into our RIIO-ED2 business planning.

6. Access SCR

OVQ30. 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?

We have not identified further material impacts. However, they are difficult to predict especially since the Minded to Consultation hasn't yet been published.

The SSMC describes the high-level impacts in principle, and we have not identified any further material impacts. However, identifying the impacts in principle is only partially useful in understanding the materiality of the impact. Even once the Access SCR Final Decision has been made it will be difficult to predict the impact of the changes because, to a very large degree, this will depend on customer responses to the changes. In particular, it is hard to know to what extent making the connection boundary shallower or enabling more options for connection will result in an increase in the demand for connections, when and where that increased demand will materialise and the resulting use of network capacity and need for reinforcement.

Our initial view is that the package of uncertainty mechanisms that has been included in the proposals, particularly those relating to network capacity, should provide adequate mechanisms to enable companies to manage the uncertainties set out above. However, at the time of writing, Ofgem has not yet published its Access SCR Minded to Consultation, now expected later in the autumn. It is therefore hard to be definitive about this and we would urge Ofgem to consider the interactions between its proposed Access SCR decisions and its proposed SSMD at the time the Minded to Consultation is published.

At this stage in the process it is also unclear how the market may react to any changes in the final years of RIIO-ED1 i.e. delaying connections activity until any new rules take effect. Similarly, any grandfathering arrangements will need to be fully worked through in a transparent and fair manner to maintain confidence and legitimacy with how network access has, and will be paid for.

OVQ31. 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 that this seems the most pragmatic approach to dealing with the timing issues identified.

OVQ32. How do DNOs propose to demonstrate the impact of our Access SCR reforms on RIIO-ED2 Business Plans?

As suggested in the SSMC, we will use the Minded to Consultation position to inform our Draft RIIO-ED2 Business Plan. As we do not have sight of the arrangements that will be proposed under the SCR at this stage, we cannot provide details of how this will impact our business plan submission. However, given the scope of the SCR, we expect this to impact areas of the business plan that cover load-related and connections-related expenditure. The reforms are not only likely to impact our submission in these areas but also the design of the price control mechanisms that will operate in these areas, for example volume drivers and unit costs. There will also be consequential impacts on the proportion of indirects, business support and non-operational capex costs that remain inside the price control (i.e. net controllable costs after allocations).

OVQ33. 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?

It would be useful if DNOs were to adopt a reasonably consistent approach to estimating the potential impact of the changes.

We note that Ofgem does not expect its work on Access SCR Impact Assessment modelling to generate specific values that can be input into DNOs' business plans. However, we think it would be useful for Ofgem to set out how it thinks that its work can and should be used so that there is some level of consistency: it would be useful if there were common guidance to DNOs on a preferred way of estimating demand impacts. It would also be useful to have access to Ofgem's modelling data which may assist in reflecting the impact of the decision in Business Plans. Ofgem should clarify its expectations of what would represent a sufficiently robust estimate to inform a decision to include additional costs within base allowances or to rely on uncertainty mechanisms.

Our ability to best reflect Ofgem's proposed reforms in our Business Plan will be dependent on the clarity provided in the Access SCR Consultation and Decision.

7. COVID-19

OVQ34. 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?

Yes, we are of the view at this stage of the COVID-19 pandemic that it would be prudent for Ofgem to have some form of mechanism in place to cater for potential longer-term impacts of COVID-19 on RIIO-ED2. We strongly supported the proactive stance Ofgem took at the outset of COVID-19 and the regulatory easement framework and supplier liquidity arrangements that industry and Ofgem worked closely and collaboratively on to deliver in a timely manner.

Our current thinking is that for output and incentive arrangements, where appropriate, the RIIO-ED2 regulatory framework should include recognition of external factors which may affect performance and the timing of the delivery of outputs – for example this could be an extension of the "exceptional events" mechanism that exists in the RIIO-ED1 Interruptions Incentive Scheme. Building in sufficient flexibility to RIIO-ED2 mechanisms up front should provide Ofgem with a more agile price control framework and avoid the need for significant ad hoc work in a constrained timeframe were further waves of COVID-19, or any other form of pandemic, to affect the country.

As a separate element to deal with the potential longer-term impact of COVID-19 we have given consideration to building on Ofgem's thinking with respect to making RIIO-ED2 more dynamic and reflective of outturn conditions. As noted in our response to COQ16 on indexation of Real Price Effects (RPEs) we are broadly supportive of this approach and believe there may be merit in extending this approach to Ongoing Efficiency, such that the effects of COVID-19 on productivity can be accurately reflected in any Ongoing Efficiency values applied in RIIO-ED2. For example, if Ongoing Efficiency is calculated as 1 per cent per annum, but the revealed, longer-term impact of COVID-19 on productivity was 0.2 per cent per annum, the net Ongoing Efficiency value applied in RIIO-ED2 would be 0.8 per cent per annum. In theory, this framework, akin to that proposed by Ofgem for RPEs, could be updated annually, enhancing the accuracy of the price control further and avoiding windfall gains or losses due to erroneous forecasting.

QUESTIONS IN SSMC ANNEX 1 – DELIVERING VALUE FOR MONEY SERVICES FOR CONSUMERS

8. Approach to setting outputs and incentives

OUTQ1. Do you agree with our proposal for setting upper and lower limits on the value of bespoke ODIs?

Yes, we agree that there is merit in setting upper and lower limits on the value of bespoke ODIs. Given they are likely to be newer or more novel output areas, with potentially less historical data to set targets on there is merit in ensuring that customers and licensees are not unduly exposed, and Ofgem itself has in the past taken a progressive approach to introducing new incentives, with financial exposure often being limited initially whilst a new mechanism is established and proven to work. Having a lower limit also has merit given the risk of creating a myriad of very small ODIs if there were no threshold in place. There may be value in Ofgem cross-checking the precise lower limit for financial ODIs in the Sector Specific Methodology Decision to ensure that this does not end up being higher than any of the common ODIs that Ofgem put in place i.e. if a common ODI has a financial exposure of 0.2% of base revenue, then the bespoke ODI lower limit may want to be aligned with this.

With respect to setting these thresholds, we would welcome clarity on whether Ofgem ultimately intends to set these parameters using Return on Regulatory Equity (RORE) basis points as the units. This is consistent with both how the majority of RIIO-ED1 incentives were calibrated, and how Ofgem propose to calibrate the RIIO-ED2 RAM. Alternatively, Ofgem could revert to a DPCR5 approach of calibrating incentives with respect to base revenue. UK Power Networks' preference would be to retain a RORE calibration of the respective incentives.

OUTQ2. Do you agree with our proposal for a minimum value for bespoke PCDs?

Yes, we agree there is merit in providing clarity to licensees and stakeholders on the minimum value of a proposal for inclusion as a bespoke PCD, as this should drive a greater degree of consistency in application of this new element of the RIIO framework and avoid Ofgem being faced with an excessive number of low value proposals. However, there may need to be consideration of whether this threshold must apply in all instances for all DNOs within a group. For example, through customer research and stakeholder engagement a group such as UK Power Networks may find support for an activity such as the unlooping of services. There may be strong support across all three networks, and scope to undertake work in all three networks, however, the proportion of properties requiring this activity may differ to the extent that only two of the three networks meet the £15m threshold proposed by Ofgem. In this instance our understanding from the SSMC is that for the third network, we should not include a bespoke PCD, despite equivalent customer and stakeholder support. We would welcome clarity from Ofgem on this point and consideration of whether a "group level" and/or a "per customer" threshold may be more appropriate.

9. Meet the needs of consumers and network users: Customer

OUTQ3. Do you agree with the proposed scope and associated customer category weightings for the satisfaction survey?

We are in broad agreement with the approach proposed by Ofgem in relation to the customer satisfaction survey. However, we believe the proposals miss an opportunity to provide greater focus on important customer groups in the RIIO-ED2 period and to reflect advances in best practice for gathering customer feedback through digital channels.

Introducing Priority Services Register (PSR) and Low Carbon Technology (LCT) customer categories

We agree that the approach adopted in RIIO-ED1 has been successful in achieving meaningful improvements in customer satisfaction across customer connections, interruptions and general enquiries. As such, we do not believe that there is a compelling case for major changes to this framework with respect to these customer categories and the relative weightings for interactions that fall within these established categories. However we believe further consideration should be given to adding new categories with appropriate weightings to concentrate focus on particular customer categories.

We agree that both PSR customers who experience an interruption and customers who invest in low carbon technologies (LCTs) are important categories of customers, which we already separately identify, and that it is right to monitor customer service performance for these categories separately. However, we disagree that PSR customer volumes are insufficient to form a statistically significant sample and, as such, we believe that there should be a separate financial incentive on DNO performance in this area.

With respect to LCT customers, we recognise that current volumes may be insufficient to support a financial incentive at this point in time. However, we believe that Ofgem should consider the introduction of an incentive as soon as the volumes reach a sufficient level. Given the expected increase in such interactions over time, this is an opportunity to make appropriate use of adaptive regulation by setting out proposals ahead of the RIIO-ED2 period which detail the triggers and parameters for such an incentive. The volumes of interactions for inclusion in the survey in this area may be supported by increasing the number of channels through which we survey customers as mentioned below.

We would welcome further discussions with Ofgem regarding the potential for separate incentivisation of PSR and LCT customers in the satisfaction survey.

As stated in our response to the RIIO-ED2 Open Letter on 15 October 2019, we would welcome the introduction of a framework that allows us to use additional contact channels for gathering feedback from customers over and above the current RIIO-ED1 telephony channel. Recent data from the Institute of Customer Service, an organisation which measure customer satisfaction across GB through its UKCSI metric, shows customers are choosing to use a variety of channels, both in terms of contact they have with organisations before/during/after service delivery, and in providing feedback. In line with this trend, we would expect customers to also be given choice as to how they provide feedback on their satisfaction with services provided.

Incentivising DNO service to Electricity Distributed Generation and Storage

Generators and storage providers are connecting to distribution networks in greater numbers and this trend will only continue as the transition to Net Zero gains pace during RIIO-ED2. Increasing amounts of energy will be exported via distribution networks, with exporters' revenues heavily dependent on the networks operating consistently and reliably. It is therefore vital that networks deliver the quality of service that providers expect: generators already connected to our network consistently tell us that their primary concern in relation to service is the continued access to the network to enable them to export energy because every interruption represents lost revenue and profit. They are increasingly vocal on this point.

Under RIIO-ED1 there is no incentive which directly targets provision of service to energy providers once they have been connected to the distribution networks: they are subject to incentives on connection (via Incentive on Connections Engagement (ICE)) but they are not covered by BMoCS and they are not covered by the Interruptions Incentives Scheme. As distributed generation and storage becomes more prevalent and important, the lack of such an incentive begins to look increasingly unbalanced and could potentially distort the decisions and actions of DNOs to the detriment of providers.

The lack of an incentive should and could be addressed for RIIO-ED2. We have identified two potential forms of incentive.

A specific targeted incentive could be introduced based on an appropriate measurement (such as the duration of interruptions, or a notional amount of energy not transported, or perhaps a combination of these). This would need to be baselined against current levels of performance and, given expected level of growth in this segment should be a relative rather than absolute measure. An advantage of this approach would be that it specifically and explicitly targets the concern that is most pressing and important to customers. It is also mechanistic and thus clear and transparent. It would avoid the burden associated with incentives relying on surveys and ex-post evaluation.

Another approach might be to extend the BMoCS or to introduce a similar style customer service incentive, based on surveying and/or ex-post assessment to such providers. The advantage of this is that it could capture all aspects of service quality. However, it would rely on a survey and an evaluation of the results of the survey and as a result could be seen as less transparent. A baseline level of customer service would also need to be established.

On balance, we consider, on the basis of the evidence of engagement with providers to date, that a quantitative incentive could be the most appropriate. However, we will be guided primarily by further engagement. It may be that both types of incentives could have a role. We would also want also to test the idea with other DNOs to consider whether this should be a common incentive, although the driver may vary across regions: not everywhere will see the same incidence of distributed energy resources. We would also look to work with Ofgem, industry and stakeholders to develop these ideas.

Broadening channels for measuring customer satisfaction

As stated in our response to the RIIO-ED2 Open Letter on 15 October 2019, we would welcome the introduction of a framework that allows us to use additional contact channels for gathering feedback from customers over and above the current RIIO-ED1 telephony channel. Recent data from the Institute of Customer Service, an organisation which measures customer satisfaction across GB through its UKCSI metric, shows customers are choosing to use a variety of channels, both in terms of contact they have with organisations before/during/after service delivery, and in providing feedback. In line with this trend, we would expect customers to also be given choice as to how they provide feedback on their satisfaction with services provided in RIIO-ED2. This would bring our industry up to speed with the latest best practice being employed in other sectors such as banking, insurance and telecoms. This has the potential to capture feedback from a wider distribution of customers to more accurately reflect customer satisfaction and support development of our service offerings to improve the customer experience.

OUTQ4. Do you agree with our proposed approach to target setting and calculating rewards and penalties in RIIO-ED2?

We agree that it is appropriate to set the same targets for all DNOs across customer categories to ensure that customers receive a similar quality of service regardless of their location and the service performance across DNOs can be readily compared.

Dynamic targets would introduce additional complexity and reduce transparency. It would also provide DNOs with less certainty with regards to planning for customer service improvements. As Ofgem acknowledge, as performance improvements are likely to be incremental, a dynamic approach may, in reality, result in little or no change to targets. We also agree with Ofgem that a static target would nonetheless reflect increasing customer expectations over time and therefore include a degree of dynamism as scores are awarded by customers based on the level of service provided by customers relative to their expectations. As such, it is our view that, at this time, the potential benefits of dynamic targets are outweighed by the associated costs.

Ofgem has proposed that targets are based on mean RIIO-ED1 performance with rewards applicable to upper quartile performance and penalties applying to scores below the average. A dead-band would apply between the average and upper quartile scores where no financial incentive applies. We agree with the broad principles behind this proposal. However, should DNO performance levels cluster further before targets are set, care may be needed to ensure that the resultant incentivised range is not too narrow resulting in an incentive rate that is too sensitive to relatively small changes in performance.

Ofgem has also proposed that the maximum reward score is calculated as the upper quartile score plus 1.75 standard deviations. This calculation appears to be arbitrary and we do not understand the relevance of the variance between the scores in target setting. In addition to this, if the RIIO-ED1 upper quartile score is high but

scores below the upper quartile show large variance, this calculation could result in a maximum reward score that is above 10 out of 10, which naturally does not make sense.

We understand that this approach was applied in the RIIO-GD2 sector and produced a reasonable set of targets based on the trial data. However, the methodology for RIIO-ED1 would either need to be designed to cater for the two issues outlined above or an additional step added to assess whether the targets produced are appropriate.

We think that the incentive value of +/-1% of allowed revenue or equivalent in terms of RORE basis points remains an appropriate strength of incentive in this area.

OUTQ5. Do you agree with our proposed approach to setting complaints metric targets in RIIO-ED2?

We agree that it is appropriate to retain the complaints metric as a penalty only incentive in RIIO-ED2 with an incentive strength up to -0.5% of base revenue or equivalent in terms of RORE basis points.

We agree that the target score of 8.33 should be updated to reflect the current standard of complaints resolution. However, in setting complaints targets for RIIO-ED2, Ofgem should be cognisant of the fact that the incentive is a penalty only regime, and therefore set a target that reflects its purpose to ensure truly poor performance is penalised, rather than penalising performance which may be good, but not exceptional.

We agree that a static target is a proportionate approach for this incentive as the costs of the additional interventions associated with a dynamic target cannot be justified given the strong levels of performance already achieved.

We continue to believe that an indicator measuring the number of complaints on a standardised basis, e.g. per 10,000 customers would be beneficial, driving DNOs to improve the services they provide to all customers in order to reduce the absolute number of complaints they receive.

We note Ofgem's position in the SSMC that the intent of the complaints metric is to incentivise the handling of complaints rather than the number of complaints received and that the quality of service provided is already captured by the customer satisfaction survey. However, DNOs also receive complaints from parties that are not captured by the Customer Satisfaction Survey in relation to work we are undertaking, but where they are not the direct customer. Adding this measure to the Complaints arrangements for RIIO-ED2 would bring the framework more in line with the environment organisations outside the sector face. These companies face natural pressure to ensure complaints do not arise from any customer as well as the pressure to resolve them quickly and effectively when they do. This would also mean that reported performance better reflects the overall customer experience. We would welcome further discussions with Ofgem on this issue.

OUTQ6. Do you agree with our proposal to remove the Stakeholder Engagement and Consumer Vulnerability Incentive in RIIO-ED2?

We agree that stakeholder engagement will continue to be critical to effective network operation in RIIO-ED2. We have worked hard to engage extensively and develop a relationship of trust with our customers and stakeholders. Our customers and stakeholders have gone to considerable effort to understand our business and determine how we can improve in the future. They trust that their views will lead to tangible change, reflected both in our business plan, which has customer and stakeholder engagement, and the views of our Customer Engagement Group (CEG), at its heart, and also in the initiatives that we continue to develop throughout the RIIO-ED2 period.

We agree that the efforts DNOs have put in through RIIO-ED1 and previous price control periods means that engagement of customers and stakeholders is now thoroughly embedded in our activities and business as usual processes.

Noting that Ofgem are proposing to introduce mechanisms in key areas of the price control that will be heavily driven by stakeholder engagement, we believe these mechanisms can benefit from adopting the positive developments of the Stakeholder Engagement and Consumer Vulnerability (SECV) framework. Namely, having clear assessment criteria and routine evaluation throughout the price control are key to ensuring the actions driven by such mechanisms are focused on delivering for customers. Feedback from stakeholders and Ofgem within the period allows quick course correction which cannot be achieved through ex-post assessment at the very end of the price control.

Therefore, we agree with the removal of the SECV in its current form noting that our engagement and activities regarding customers in vulnerable circumstances will continue to be incentivised through other proposals for the RIIO-ED2 price control.

10. Meet the needs of consumers and network users: Connections

OUTQ7. Do you agree with our proposal to expand the connections element of the customer satisfaction survey?

We agree in principle with Ofgem's proposal to expand the connections element of the customer satisfaction survey if it can be demonstrated that it does not include customers from market segments with sufficient competition. We also agree that some large connections customers may sometimes have more in common with minor connections customers (those requiring Single Service Low Voltage (LVSSA) or Small Project Demand (LVSSB) connections) and the service they receive would be better captured through a process similar to that of the customer satisfaction survey. However, as we state in our response to OUTQ8 below, care will need to be taken in defining the scope of the expansion of this element of the customer satisfaction survey to ensure that the appropriate connections customers are captured.

It is also important that any change in scope of the customer satisfaction survey to include larger connections customers is consistent across the sector. This is important to ensure that the performance measured by the survey continues to be comparable across companies, a vital feature which ensures the survey's effectiveness.

Any change of scope of the survey would also need to be reflected when setting ambitious targets for the customer satisfaction survey.

OUTQ8. Do you consider that we have identified the relevant considerations to determine which customers should be captured in its scope?

As stated above, we broadly agree that it may be appropriate to expand the connections element of the customer satisfaction survey. This should be for where customer interactions are sufficiently high in volume and either form part of a market segment where there is no competition or constitute a subset where no competition occurs or is likely to occur. Noting our response to OUTQ7 with respect for the need for commonality of segments within the incentive across all DNOs.

Whilst some subsets of some market segments may be appropriate for inclusion, it may be necessary to apply a capacity limit, as beyond a certain capacity limit, such connections customers will be increasingly complex, occur in lower volumes and be subject to competition. For example, while the majority of customers connecting at Low Voltage will be smaller customers, some may be larger developers with repeat business and therefore performance better measured through the major connections arrangements.

Separate consideration should be given as to whether incorporation of the same customers into the Time to Connect (TTC) financial incentive is appropriate. We discuss our view on reported performance reflecting customer expectations on timeliness in relation to OUTQ11 below. However, we note here that the proportion of customers for which timeliness, rather than speed, particularly in relation to the completion of connections, is a priority, will likely be higher for the major connections segments that may be proposed for inclusion in the incentive. The underlying projects associated with these connections are more likely to have longer, phased timescales which would introduce volatility to performance, especially considering volumes are likely to be lower.

We note that this could result in a difference in scope between the Broad Measure of Customer Satisfaction (BMCS) and TTC, if such customers are considered for inclusion in the customer satisfaction survey. However, the scope between the two incentives is already different (for example, TTC does not include service alterations) and the decision should be based on the suitability of the incentive mechanism rather than achieving identical scopes.

We will continue to work with Ofgem through the Working Groups to explore these issues further and understand the extent of competition within connections market segments, the associated volumes and their comparability.

OUTQ9. Do you agree with our proposal to retain the TTC incentive as a financial ODI in RIIO-ED2?

We agree that the TTC incentive should be retained as a financial incentive in RIIO-ED2. The incentive has driven considerable performance improvements through RIIO-ED1. There remains room for further improvement across the industry, particularly in the face of new challenges driven by the transition to Net Zero and the implications of the Access Significant Code Review.

One significant drawback of the incentive, as currently defined, is that it does not reward, and in fact can penalise, the delivery of connections within the timescale reflective of the customers' requirements. An exclusive focus on the

speed with which customers are provided with quotations and connections fails to recognise the value that customers often place on the synchronisation of connections with their construction schedules. We would welcome an incentive mechanism that recognises the value of such an approach. In the absence of this, and as discussed further in our response to OUTQ11 below, we would request that further consideration is given to ensuring the mechanism measures performance reflective of the customer requirements rather than the often misleading measure of the time between acceptance and delivery. We believe detailed work is required to ensure the mechanism for RIIO-ED2 more accurately reflects the real-world challenges faced in delivering physical works which often involve digging up local streets.

OUTQ10. Do you agree with our proposal to include a re-opener which allows us to revisit targets, and potentially introduce penalties, in the period?

We do not agree with Ofgem's proposal to include a re-opener which allows Ofgem to revisit targets and introduce penalties within the period. We believe that such a re-opener would introduce uncertainty for DNOs, inhibit planning and undermine the stability of the incentive.

We note that there was a mid-period review of targets for the TTC incentive in RIIO-ED1. However, the TTC incentive was introduced as a new incentive in RIIO-ED1 with very limited data available for target setting before the price control period commenced. The RIIO-ED2 price control will also only be 5 years long as opposed to the eight years of the RIIO-ED1 period. Having a mid-period review of targets would mean revisiting targets after only two or three years and is unnecessary due to the improved availability of reliable data for setting targets at the beginning of the price control.

All connections provided for customers are covered by Guaranteed Standards of Performance (GSoP) which include standards on providing timely quotes and delivery of connections. These standards will continue to ensure that customers are not negatively impacted by poor performance while the TTC incentive will drive improvements and reveal excellent performance. Therefore, we do not believe there is a need for a re-opener to consider the application of further penalties in this area.

OUTQ11. Do you agree with the methodology we propose to use to set the new TTC targets?

We agree with Ofgem's proposal to retain the current basis for determination of the minimum and maximum reward scores, namely average industry performance for the minimum reward score and 30% below this for the maximum reward score (subject to no deterioration of targets from RIIO-ED1 levels). This has proved a reliable way to set targets for this incentive for the latter four years of RIIO-ED1, a similar period of time as that for the RIIO-ED2 period.

Care would also need to be taken in setting the targets if the scope of the incentive is expanded to include new connections categories. There may be the potential for collecting shadow data for the remaining years of RIIO-ED1 to inform any differences.

As stated above, we believe that the TTC incentive should reflect circumstances where customers do not want connections to occur simply as quickly as possible, but rather they want a connection timescale to match their specific work schedule. Reported performance is negatively impacted for accommodating customers' requirements in this way, or accommodating changes to customer required timescales which is inappropriate and does not reflect the service customers are receiving. It is inappropriate to have an incentive which penalises companies for actions which benefit customers. As noted above, the proportion of such customers is likely to increase if the scope of the TTC is expanded making this issue all the more relevant if this is implemented.

Finally, we believe that the incentive scale for the TTC incentive for RIIO-ED2 should be linear between the minimum and maximum reward scores to ensure that performance improvement for all DNOs is incentivised equally.

We would welcome further discussions with Ofgem about how the TTC incentive can be modified to eliminate perverse incentives and unintended consequences.

OUTQ12. Do you have views on our proposed Connection Principles and associated standards (in Appendix 4) for RIIO-ED2? Do you disagree with any of the standards we have proposed? If so, why?

We agree that the principles and associated standards outlined in Appendix 4 seem broadly reasonable and suitable for ensuring connections customers receive the service they require.

However, it is our understanding that DNOs' Connections Strategies should only cover those market segments that do not yet have sufficient competition to ensure effective customer choice of provider. The proposed baseline standards will not necessarily be relevant to all customer segments. Therefore we would require clarity on how Connections Strategies will be assessed against the baseline standards for the purposes of step 1 of the Business Plan Incentive.

In addition, this places importance of the results of competition tests to determine if market segments are deemed to have sufficient competition for exclusion from this incentive. Ofgem's current proposal is to use the results of the competition tests run in 2013 for the purposes of informing RIIO-ED1 arrangements. The results of these tests will be a reflection of the state of competition 10 years before the beginning of the RIIO-ED2 period and 15 years before the end of the period. This will not reflect the impact of the significant work companies have carried out to facilitate and promote competition in all market segments. The positive impact of this work means that the current status of competition across the sector is likely to be materially different from that of 2013 which should be reflected in RIIO-ED2 arrangements. We strongly encourage Ofgem to take steps to re-assess the levels of competition in relevant market segments ahead of the RIIO-ED2 price control period starting.

Notwithstanding the points made above, we believe two of the baseline standards require further consideration to ensure they are appropriate in general:

Under principle 3, the baseline standards suggest companies are expected to:

- **"Ensure the availability of flexible connections for all customers, including storage."** While we agree that flexibility has the potential to better reflect customer needs and address future load growth efficiently, such arrangements through connection agreements may not be suitable for all customers. Ofgem have recognised this fact in their decision to not explore better definition of Access Rights for "small users" under the ongoing Access SCR. Such arrangements being embedded within the connections process for all users could introduce unnecessary complexity for many customers with little additional benefit. In addition to the question on suitability, provision of this option for all customers including domestic could lead to a requirement for significant investment in systems to facilitate it. This outcome may be more suitably and efficiently achieved through other routes to flexibility such as procurement of flexibility, potentially through aggregators or other third parties for some users.
- **"Have processes in place for the promotion of certain types of customers (such as storage) in connection queue if it will help others connect more quickly/cheaply."** We recognise the merits of such an approach in general, however care must be taken to ensure such arrangements are genuinely in the benefit of all customers looking to connect to the electricity system. Achievement of this baseline standard may be heavily linked to the outcome sector-wide work in this area to develop and assess such processes and shouldn't conflict with the outcome of such assessments.

We welcome further dialogue with Ofgem on the use of competition test outcomes and the suitability of baseline standards through the continuing RIIO-ED2 Working Groups.

OUTQ13. Do you have views on our proposal to use the Business Plan Incentive to encourage companies to reveal higher baseline standards of performance and to apply this, where appropriate, to all DNOs?

We think that the BPI could represent an effective tool for incentivisation if Ofgem makes a clear and credible commitment to reward those DNOs that reveal higher baseline standards. However, we do not support the retrospective application of enhanced baseline standards post business plan submission. DNOs' business plans will be built on evidence of what their customers and stakeholders want and are willing to pay for. Retrospectively applying new standards that have not been identified from this extensive engagement and research appears to be at odds with the approach of putting customers at the heart of RIIO-ED2 business plans.

Additionally, we would expect all DNOs to price the attainment of baseline standards in their respective business plans and have appropriate systems and process in place to deliver these. Moving the goal-posts after submission of costed business plans, potentially to meet "aspirational" levels of performance that the proposer has never achieved does not have our support.

OUTQ14. Do you agree with our proposal to use an ex post assessment to penalise/reward companies who fail to deliver their strategies in line with our guidance/exceed performance targets?

It is in the interests of customers that performance appraisal is timely and DNOs have clear output measures to ensure both that DNOs have the opportunity to take corrective action sooner rather than later and that they are appropriately incentivised. As such, we believe that ex post incentive mechanisms should only be applied where an ex ante mechanism is infeasible.

In the case of holding DNOs to account for delivery of their Connections Strategies, we believe the positive elements of mechanisms from RIIO-ED1, such as SECV, should be used as a basis for new mechanisms. Clear assessment criteria should be established ahead of the start of the RIIO-ED2 period and routine appraisal of performance against these should be core to the assessment of the delivery of the strategy. Such clarity is necessary to fully support DNOs to go above and beyond in providing value to connections customers.

However, such clarity should not come at the expense of the agility of DNOs to respond to changing circumstances and innovate. The assessment framework will need to recognise that:

- Different DNOs may choose different delivery solutions to address common problems;
- Each DNO will face issues that are specific to them given the varying composition of their connections customer base; and
- Customer priorities are likely to change through the price control period. We have seen evidence of this in the RIIO-ED1 period where we started the period with a strong focus from our stakeholders on arrangements for Distributed Generation and have seen this shift towards connection of Electric Vehicles in more recent years.

We are happy to work with Ofgem to establish the ex ante clarity required for such an assessment to be effective.

OUTQ15. Do you consider that an assessment of performance in the middle and at the end of the price control is a proportionate approach?

Subject to the requisite clarity being provided on the process that will be used to conduct the assessment, we agree that assessing performance once within the price control, as well as at the end, is a proportionate approach, as it avoids the administrative burden of annual assessments.

We actively support a mid-period assessment, rather than reliance on a single end of period assessment, as this reduces process risks for both Ofgem and the DNOs and spreads some of the workload away from period end when RIIO-ED3 processes are underway. It also affords an opportunity to disseminate learning and improve customer experiences within period rather than leaving everything till the price control has concluded. However, if there is insufficient clarity on the assessment process ex-ante or the proposed mechanism for assessment evolves during the period, annual guidance and communication between Ofgem and the DNOs may be necessary to fully support DNOs to go above and beyond in providing value to connections customers.

OUTQ16. Do you agree with our proposal to retain the Connections GSoPs for all connection customers in RIIO-ED2?

We agree that the existing standards are fit for purpose and should be retained for RIIO-ED2.

OUTQ17. Do you agree with our proposed approach to uplifting the Connections GSoP payment values in line with inflation, indexing payment levels to inflation, and rounding to the nearest £5?

As we reiterate in our response to OUTQ41, whilst we agree that payment amounts (and caps) should be adjusted for inflation (CPIH) with payment amounts rounded up or down to multiples of £5 as appropriate, we believe a pragmatic approach would be to do this once. This approach was adopted for the longer, RIIO-ED1 price control and as stated previously we believe setting once avoids the need for annual updating of the relevant Statutory Instrument for potentially minor adjustments.

OUTQ18. Do you agree with our proposal to remove the Incentive on Connections Engagement for RIIO-ED2?

We agree it is appropriate to remove the Incentive on Connections Engagement (ICE) to be replaced by more comprehensive arrangements that also recognise the increase in competition in the connections market since 2013.

11. Meet the needs of consumers and network users: Consumer Vulnerability

OUTQ19. Do you agree with our proposed approach to ensuring consumers in vulnerable situations receive an appropriate range and level of support in RIIO-ED2? If not, what alternative approach should we consider?

Improving the services and support to our vulnerable customers is a core element of our company strategy and business plan. We will continue to strive to identify all of our vulnerable customers and ensure that they receive the support that they need from us. As such, we welcome Ofgem's proposed approach to ensuring that customers in vulnerable situations receive an appropriate range and level of support during RIIO-ED2.

We think that the BPI could represent an effective tool for incentivisation if Ofgem makes a clear and credible commitment to reward those DNOs that propose to go beyond the baseline standards of performance under the Consumer Value Proposition (CVP) element of the BPI. As noted above in our response to OUT13 however, we do not support a post submission increase in baseline standards of performance.

We set out our views on the BPI in greater detail in our response to COQ52.

In addition, further clarity on how the ex-post assessment underpinned by a financial incentive will work in practice will be required to ensure that DNOs can be confident that delivering additional value for customers will be recognised and rewarded appropriately.

We will continue to work with other DNOs, stakeholders and Ofgem to develop common metrics and a reporting framework within the RIIO-ED2 working group.

OUTQ20. Do you have views on our proposed Vulnerability Principles and associated standards (in Appendix 5) for RIIO-ED2? Do you disagree with any of the standards we have proposed? If so, why?

The principles and associated standards outlined in Appendix 5 seem broadly reasonable for establishing an industry baseline for an appropriate minimum level of service. However, we are proud of our achievements in supporting our vulnerable customers and will continue to challenge ourselves to perform well in excess of the industry baseline in this area.

OUTQ21. Do you agree with our proposal to use an ex post assessment to penalise/reward companies who fail to deliver their strategies in line with our guidance/exceed performance targets?

It is in the interests of customers that performance appraisal is timely and DNOs have clear output measures to ensure both that DNOs have the opportunity to continue to tailor their approach sooner rather than later. As such, we believe that ex post incentive mechanisms should only be applied where an ex ante mechanism is infeasible.

In the case of holding DNOs to account for delivery of their Vulnerability Strategies, in line with our response to OUTQ14 above, we believe the positive elements of mechanisms from RIIO-ED1, such as SECV, should be used as a basis for new mechanisms. Clear assessment criteria should be established ahead of the start of the RIIO-ED2 period and routine appraisal of performance against these should be core to the assessment of the delivery of the strategy. As stated above, such clarity is necessary to incentivise arrangements to support DNOs to go above and beyond in providing value to vulnerable customers.

However, such clarity should not come at the expense of the agility of DNOs to respond to changing circumstances and innovate. The assessment framework will need to recognise that:

- Different DNOs may choose different delivery solutions to address common problems; and
- Each DNO will face issues that are specific to them given the varying composition of their vulnerable customer base.

With this in mind, it may be appropriate that the incentive arrangements are a combination of an annual performance incentive for quantifiable measures and a mid-period and end-of-period ex-post assessment of performance for qualitative assessments of performance. We are happy to work with Ofgem to establish the ex ante clarity required for such arrangements to be effective.

OUTQ22. Do you consider that an assessment of performance in the middle and at the end of the price control is a proportionate approach?

Subject to the requisite clarity being provided on the process that will be used to conduct the assessment, we agree that assessing performance once within the price control, as well as at the end, is a proportionate approach, which avoids the administrative burden of annual assessments.

We actively support a mid-period assessment, rather than reliance on a single end of period assessment, as this reduces process risks for both Ofgem and the DNOs and spreads some of the workload away from period end when RIIO-ED3 processes are underway. It also affords an opportunity to disseminate learning and improve customer experiences within period rather than leaving everything till the price control has concluded. However, if there is insufficient clarity on the assessment process ex-ante or the proposed mechanism for assessment evolves during the period, informal annual guidance and communication between Ofgem and the DNOs may be necessary to fully incentivise DNOs to go above and beyond in providing value to vulnerable customers.

12. Maintain a reliable network

OUTQ23. Do you agree with our proposed approach to retain the RIIO-ED1 methodology for setting unplanned interruptions targets?

We agree that the RIIO-ED1 methodology for setting unplanned interruptions targets should be retained for RIIO-ED2 as the existing methodology has proven to be robust and provides consistency and transparency in incentivising DNO performance.

We note Ofgem's proposal to set each DNO's target at the lower of its current performance (at the time of setting targets) and the target produced by the methodology. Ofgem state that this is to avoid "DNOs being rewarded again for a level of performance for which they have already received a reward, meaning customers pay twice for the same level of service".

However, we note that in instances where the annual ED1 cap on IIS revenues has been applied, DNOs have **not** been rewarded for all of this frontier performance. For example, in the case of LPN, had the cap on revenues not been in place, an additional £8.58m of IIS revenues would have been received to date during RIIO-ED1. Performance at the frontier benefits not only customers of the network concerned but customers across Great Britain as it provides valuable information to Ofgem and other DNOs on what is achievable and pushes all DNOs to improve. As such, we believe that frontier performance should be specifically incentivised and rewarded. We therefore propose that, rather than setting each DNO's target at the lower of its current performance (at the time of setting targets) and the target produced by the methodology, the target should be the lower of the average of its performance over the last four years and the target produced by the methodology. The use of four years aligns with the number of years predominately used in Ofgem's own target setting model and also removes the risk of targets being affected by a single year's performance.

OUTQ24. Do you have views on the alternative approaches to setting unplanned interruptions targets set out? Are there any other approaches that we have not considered?

Alternative approaches considered by Ofgem included;

- setting targets on a rolling-average basis,
- disaggregating DNOs' performance on Low Voltage (LV) circuits,
- setting duration of interruptions to supply per year (CML) targets in a way that means they are not a secondary function of the Customer Interruptions (CI) target, and
- incorporating elements of the Worst Served Customer mechanism into the IIS.

We agree with Ofgem that there is not a clear case for an entirely new or different approach to setting targets from the one which has delivered well for customers in RIIO-ED1. The current approach is well understood and has demonstrated that it can successfully incentivise the performance improvements customers require. We also agree that consistency of approach over time is valuable in terms of transparency of performance monitoring and holding DNOs to account.

In particular, we note that disaggregating DNO performance on LV circuits would add significant complexity and risk untested calibration and unintended consequences. Given the expected focus on LV networks in the future we would welcome work in the remainder of RIIO-ED1 and into RIIO-ED2 to capture appropriate data such that LV circuit disaggregation could be feasible in RIIO-ED3.

OUTQ25. What are your views on revisiting unplanned interruptions targets within the price control period?

We agree with Ofgem that the setting of dynamic targets would not be appropriate as any potential benefit of such a change would not justify the additional complexity on top of what Ofgem acknowledges is already a complex model.

Pre-agreed targets play an important role in providing certainty to the DNOs and hence facilitate business planning to deliver network performance improvements for customers.

OUTQ26. Do you agree with our proposed position not to introduce further convergence of DNOs' targets over time?

We agree with Ofgem's approach not to introduce convergence of DNOs' targets over time.

As Ofgem notes, convergence would mean that customers in some parts of the country would face disproportionately high costs to achieve any proposed converged level of reliability and at this point in time we have seen no customer or stakeholder feedback that suggests that they would be willing to pay such costs. Ofgem's methodologies for setting interruptions incentives to date has recognised the inherent and inherited differences across networks and we believe a significant piece of GB wide engagement would be needed to underpin a move to universal reliability targets.

OUTQ27. What are your views on retaining an incentive for planned interruptions performance, and the associated targets?

We agree that it is appropriate to retain a financial incentive for planned interruptions performance and note that the number and duration of planned interruptions has reduced by 24% and 25% respectively for all DNOs since the beginning of RIIO-ED1 due to such an incentive. As discussed further in our response to OUTQ28 below, we believe that the current incentive framework works well and should be retained in its existing form.

It is also worth noting that there will not always be a downward trend in planned interruptions targets – in fact, for DNOs who have pole mounted transformers, there is likely to be an increase in planned interruptions in the period between now and the end of 2025 as work is carried out to remove any such equipment that contain PCBs from the network.

OUTQ28. What are your views on the potential amendments that could be made to the mechanism, including (but not limited to) the options presented in Tables 23 and 24?

We agree with Ofgem's proposal to retain the existing approach with planned interruptions weighted at 50% of unplanned interruptions and targets based on a DNO's average performance over three years (with a two year lag).

We believe that a 50% weighting of planned interruptions strikes an appropriate balance: incentivising DNOs to reduce the impact of planned interruptions on customers, whilst acknowledging that customers are able to mitigate the impact of planned interruptions. It also takes into account that some planned interruptions are an unavoidable part of network management and maintenance. Furthermore, a common weighting across DNOs avoids complexity and increases transparency.

The current methodology that takes a three year average of each DNO's performance as a basis for its performance target has worked well in incentivising performance improvements and is clear, self-correcting and well understood by stakeholders. As such, we do not think that there is a compelling case for changing this approach. The alternative approaches considered, such as the use of benchmarks or DNO-specific proposals, are complex and the latter could lead to large regional variations in performance.

OUTQ29. What are your views on how VoLL should be updated for RIIO-ED2?

We agree that the Value of Lost Load (VoLL) should be updated for RIIO-ED2. At the very minimum, the RIIO-ED1 figure should be updated in line with inflation (RPI). However, we believe that the VoLL should also be updated to reflect other changes since the RIIO-ED1 value was set. The Methodology Consultation notes that a report by Electricity North West (ENWL) produced an updated VoLL figure by focusing on disaggregating the model used to establish VoLL. This work on VoLL is comprehensive and we cannot see an immediate case for disregarding it. In order to ensure investment in the network is in the interests of customers, it is necessary to ensure that the value that customers place on network reliability is as accurate as possible. We would also note that, in the absence of a single, Ofgem initiated piece of customer research, we are conducting our own research for RIIO-ED2. It will be helpful to understand how such evidence will be factored in to the incentive rates devised for RIIO-ED2.

However, Ofgem note that the ratio of domestic to Small and Medium-sized Enterprises (SME) customers used by ENWL in their report could be updated to reflect more recent data released by the Office for National Statistics. This, more recent, ratio, which gives a greater weighting to domestic customers would reduce the resulting VoLL estimate (from £25,000/MWh to £23,500/MWh). We would be grateful if Ofgem could provide a specific reference for the source of this ratio so that we are able to fully understand its derivation and comment further.

Furthermore, we support the use of a specific ratio of domestic to SME customers for LPN where due to the nature of its entirely urban network with large centres of business and offices the ratio is different. We would be happy to engage with Ofgem and other DNOs on this point to ensure that all aspects of the VoLL estimates applied are fit for purpose and as up-to-date and accurate as possible.

Whilst there may be some benefits of a VoLL that can vary to reflect the differing values placed upon lost load by different customer groups, too granular VoLL estimates would introduce significant complexity and raise major practical considerations.

OUTQ30. What are your views on the different methodologies for updating VoLL?

Please see our response to OUTQ29 above.

OUTQ31. Do you have a view on retaining alignment with VoLL figures used in other RIIO price controls and/or parts of the energy sector?

Whilst consistency across RIIO price controls and the energy sector more broadly is potentially helpful, we do not believe that such alignment should be sought at the expense of accuracy/cost reflectivity. If updated data is available and/or specifically relevant to electricity distribution, this should not be ignored as this could result in sub-optimal levels of network investment and poorer outcomes for customers.

We further note that in the July 2020 Draft Determinations for Electricity Transmission, Ofgem state that: “the ENWL study findings are more suitable for the distribution network, rather than the transmission network” and it would therefore seem odd to align with other price controls or parts of the energy sector.

Furthermore, it would be counter intuitive to use VoLL figures from other prices controls which would be set three, four or even five years ahead of the start of RIIO-ED2 when the actual targets themselves are being set as close to the price control as possible.

OUTQ32. Do you agree with our proposed approach to retain the RIIO-ED1 revenue cap for the IIS at 250 RoRE basis points?

At this point in time we have seen no evidence to alter the symmetrical revenue cap for the IIS of 250 RoRE basis points. Reducing the volume and duration of interruptions remains a key customer and stakeholder priority as evidenced by recent stakeholder workshops, the participation of Citizens Advice in relevant Ofgem working groups and the research undertaken to establish the VoLL to domestic customers and SMEs. Reducing the symmetrical cap below the levels applied at RIIO-ED1 could send the wrong signal to both DNOs and customers on the importance of network reliability. We do note that the revenue cap, incentive rate strength and respective CI and CML targets all need to be considered together. Simply tightening targets for RIIO-ED2 and retaining all the other parameters constant, could result in certain DNOs being unable to attain the headline incentives available as this would require infeasible (i.e. negative power cuts) levels of performance. It would be demonstrably inappropriate within the RIIO-ED2 period to chastise DNOs that “only” achieve a small percentage of the available upside rewards available and “commend” a DNO that, as a result of being a poorer performer historically, is afforded greater scope for outperformance in RIIO-ED2.

OUTQ33. Do you agree with our proposal not to introduce an incentive on short interruptions in RIIO-ED2? If not, how should such an incentive be structured and developed?

We believe that creating an incentive around a CI equivalent metric for short interruptions in RIIO-ED2 is achievable and would benefit customers.

We are disappointed that it is not Ofgem’s current intention to progress the development of such an incentive for RIIO-ED2 and would note that if such an incentive is delayed until RIIO-ED3, customers will not materially benefit from the output of such an incentive for almost a decade. This is concerning given the forecast increases in local demand for energy and the acceleration of trends for greater working from home, the visibility and impact of short interruptions on customers will only increase.

The categories of short interruptions that we believe it would be appropriate to target or incentivise are discussed further in our response to OUTQ34 below.

OUTQ34. What are your views on a minimum standard for short interruptions for RIIO-ED2?

Our understanding of a minimum standard on short interruptions is a mechanism which includes a threshold number of short interruptions (lasting three minutes or less) per customer per year, such that individual affected customers are compensated if they experience a greater number of interruptions than this threshold level.

As minimum standards are, by definition, tied to customer-specific compensation, the number of short interruptions experienced per customer per year would need to be the metric targeted. This is different to how the CI and CML element of the IIS is set up whereby an overall reduction is targeted.

If a standard is introduced, we believe that it (or indeed any financial incentive) should only apply to short interruptions that are within the control of the DNO, and that are not associated with automation of the network to reduce Cis and CMLs. It would be inappropriate to penalise companies that have invested to prevent Cis (given the current incentive framework) if the consequence of this is a higher number of short interruptions.

Furthermore, Ofgem's proposed minimum standard represents a penalty only system that would not provide funding for any investment to improve performance.

It is also worth noting that in the absence of full smart meter rollout, the lack of phase data at LV means that fully automatic payments to customers for LV short interruptions would not be possible. For those DNOs using manual count processes on HV auto reclosers, there are additional data complexities including the inability to ascertain which regulatory year the interruptions apply to.

It is therefore questionable whether a minimum standard would provide the necessary protection to customers in a consistent manner across Great Britain. We would welcome a discussion with Ofgem regarding instances where the ability to make automatic payments varies across DNOs or customers as a result of varying data availability and how this should be managed in a way that is fair for all customers and DNOs.

Mindful of the above, we believe that the reliability and reporting of data on short interruptions should be prioritised with a view to introducing a symmetrical financial incentive targeting a CI equivalent metric for short interruptions for RIIO-ED2. A minimum standard would be difficult to administer while data issues persist and would provide little customer protection, whereas a CI equivalent metric for short interruptions would not be affected by the data issues and still drive up performance and customer benefit. We will continue to engage with Ofgem, industry and stakeholders at the RIIO-ED2 working groups to refine the mechanism we believe should be included in the SSMD.

OUTQ35. What information should we be capturing in RIIO-ED1 and RIIO-ED2 to better understand short interruptions and how DNOs are performing?

We believe that data reporting for 2020/21 should be undertaken on a reasonable endeavours basis and formal reporting for short interruptions should commence for 2021/22. We have presented on this topic at RIIO-ED2 SRR working groups earlier this year, proactively developed a template for data provision, and conducted a survey of other DNOs to understand relevant data issues.

As shown by our data template, which has already been provided to Ofgem through the RIIO-ED2 working group, we believe that data on short interruptions should be collected such that, for each short interruption incident, the following information is provided to Ofgem:

- The start and end date and time (and hence the duration) of the incident;
- The voltage at which the incident occurred;
- Whether the interruption was recorded automatically by the DNO's system or manual counts;
- The number of customers interrupted; and
- The type of short interruption (132kV DAR (delayed auto reclose), 132kV/EHV – auto close scheme, HV remote control & automation, EHV auto reclose, HV – auto reclose, LV auto reclose; or manual restoration/switching under 3 minutes).

OUTQ36. Do you agree with our proposal to retain the RIIO-ED1 SWEE mechanism?

We agree that the Severe Weather Exceptional Events (SWEE) mechanism has worked well during RIIO-ED1, it is well-understood, and remains appropriate for RIIO-ED2. Its successful operation was evidenced by its application during Storms Brendan, Ciara and Dennis earlier this year. We agree that having a pre-determined threshold provides clarity to DNOs and their customers of the applicable framework during severe weather events. We also believe that there is merit in revisiting the exclusion of public safety incidents in the 24 hour count in determining

whether a severe weather event meets the HV fault threshold. In recent years, there has been a substantial increase in HV faults due to public safety incidents during severe weather.

OUTQ37. Do you agree with our proposal to remove the OEE mechanism? If not, what evidence is there to support its retention, and what changes should be made to the existing approach to improve it?

We do not agree with Ofgem's proposal to remove the mechanism for Other Exceptional Events (OEEs).

We do not believe that the small number of OEEs occurring each year across the industry signals a failure of the mechanism. Indeed, exceptional events, by their nature, should occur infrequently. During RIIO-ED1, the mechanism has provided important backstop protection for DNOs against the impact of truly exceptional events that are beyond their control.

To date, during RIIO-ED1, we have experienced five exceptional events that have triggered the OEE mechanism. None of these have been weather-related.

Examples of when the OEE mechanism has been applied for us during DPCR5 and RIIO-ED1 include a scrapyard fire under a 132kV line, a fire under a cable bridge, simultaneous faults when a grid transformer was out of service for maintenance, the collision of a combine harvester with network infrastructure, and a bird strike on a line. We believe that it is right and appropriate that such exceptional events, which are beyond a DNOs' control to prevent or mitigate, are excluded from the IIS.

Furthermore, we do not agree that claims under the OEE mechanism for faults that occur whilst that part of the network is undergoing maintenance represent an incorrect use of the mechanism. In the example provided above of simultaneous faults on the network when a grid transformer was out of service for replacement, this was an exceptional event that was beyond our control. Whilst there would not have been a potential IIS liability had we not been maintaining/upgrading the network at that time, the work was necessary and it would not be economic to engineer the network to avoid interruptions under such exceptional circumstances. The inference of Ofgem's position is that the current N-1 resilience in place is not sufficient. We assume this is not the case and seek clarity on this point.

We also understand that Ofgem have a specific concern regarding the use of the OEE mechanism for long running weather events. If Ofgem specifically do not wish this to be within the scope of the mechanism, we are happy to engage with Ofgem and other DNOs on ways in which the mechanism could be adjusted to exclude such events from the scope.

During the Safety, Resilience and Reliability Working Group (SRRWG) meeting on 23 September, Ofgem discussed the potential to simplify or streamline the OEE mechanism if it were to be retained. We believe that further discussion with interested parties is warranted here as this option was not included as part of the SSMC. Our initial view is that a tiered approach to assessment of the claims could be a way to achieve Ofgem's aim. This could involve Ofgem's Electricity Distribution (ED) policy team, supported by the Ofgem Engineering hub, conducting the review of claims which are up to a specified level with Ofgem's appointed external examiner conducting reviews beyond this level. The level could be set at a percentage above the existing threshold for which an OEE claim can be made ensuring consistent treatment across all licensees.

If, however, the OEE mechanism is removed, we would note that the data used in the target setting models for RIIO-ED2 would need to be adjusted to include the exceptional events that had previously been excluded to ensure that the targets set for RIIO-ED2 reflect the revised scope of the incentive regime.

OUTQ38. What are your views on the threshold that should apply to either exceptional event mechanism?

We believe that the methodology for the calculation of thresholds for both Severe Weather Exceptional Events (SWEEs) and OEEs applied during RIIO-ED1 should continue to apply during the RIIO-ED2 period. In particular we believe that the SWEE thresholds should be updated to reflect more recent fault volume data. We believe the OEE thresholds of 25,000 customers interrupted and/or 2 million customer minutes lost remain appropriate. Retaining a consistent approach is also pragmatic as it avoids the need for unwinding elements of past claims in the target setting methodology.

OUTQ39. What performance do you think should be excluded under each mechanism?

We believe that performance exclusions should continue to apply on broadly the same basis as they have during RIIO-ED1 as set out in the licence. As stated above, we would be happy to engage with Ofgem if they want to tighten the scope of exclusions under the OEE mechanism to avoid “weather-related” claims.

OUTQ40. Do you agree with our proposal to retain the existing GsoPs? If not, what changes do you think are necessary and what are the reasons for them?

We agree that the existing standards are fit for purpose and should be retained for RIIO-ED2.

Whilst a change to the substance of the GsoP regulations is neither necessary nor appropriate, we agree that the regulations (i.e. the statutory instrument) would benefit from review and revision to provide greater clarity and transparency to stakeholders.

We agree that payments to customers should be automatic where possible, but note that for EGS4 (Notice of planned supply interruption) and EGS2A (Multiple interruptions – 4 or more power cuts in excess of 3 hours), full automatic payments are not possible. Smart meter data could facilitate automatic payments under EGS2A as it provides the LV phase visibility required. However, in the absence of the full roll-out of smart meters, fully automatic payments for such standards is not possible.

Please also note that for EGS4, the nature of the standard makes automatic payments impossible in all cases. By way of an example, where a DNO uses Royal Mail to deliver its notifications there is no evidence beyond a customer contact that would enable a DNO to identify a failure in that process – note that signed for delivery of such notifications is not cost efficient.

We would welcome a discussion with Ofgem regarding instances where the ability to make automatic payments varies across DNOs or customers as a result of varying data availability and how this should be managed in a way that is fair for all customers and DNOs.

OUTQ41. Do you agree with our proposal to uplift payment values in line with inflation, indexing payment levels to inflation, and rounding to the nearest £5 for clarity for stakeholders?

As per our response to OUTQ17 whilst we agree that payment amounts (and caps) should be adjusted for inflation (CPIH) with payment amounts rounded up or down to multiples of £5 as appropriate, we believe a pragmatic approach would be to do this once. This approach was adopted for the longer, RIIO-ED1 price control and as stated previously we believe setting once avoids the need for annual updating of the relevant Statutory Instrument for potentially minor adjustments.

OUTQ42. Do you agree with our proposal to retain some form of mechanism for WSC in RIIO-ED2?

We agree that it is appropriate to retain some form of mechanism for Worst Served Customers (WSC) in RIIO-ED2. The IIS incentivises improvements in average performance and it is right to ensure that DNOs are also incentivised to address performance issues for those customers suffering the worst performance as we understand the impact such faults can have.

OUTQ43. What are your views on the options presented for WSC? Are there other options that we should consider?

Whilst the objective of the worst served customers scheme is right, the proportion of allowances being spent by companies during RIIO-ED1 to date is low. There is therefore scope to improve the current scheme to ensure that the funding allocated is spent to improve the reliability of the service received by the customers the scheme is designed to protect.

If Ofgem decides to keep the incentive framework broadly the same, then changing the parameters or eligibility criteria for the scheme could improve its take up. In particular, we believe that changes to the qualification criteria would facilitate greater investment. At present, worst served customers are defined as customers experiencing on average at least four higher voltage interruptions per year, over a three year period. We do not believe it is necessary or appropriate to increase the number of customers eligible under the scheme by reducing the threshold number of faults (from twelve over three years) as this could divert funds towards customers suffering less extreme poor performance. However, the three year qualification period can inhibit DNO investment as customers can drop out of WSC classification in the third year, interrupting planning that may already be underway to address historic

poor performance. It also requires the clock to be restarted in assessing a particular customer group in the event of one unusually good year amongst a series of poor performing years. The length of the qualifying period can therefore result in significant delays to customer benefits. We therefore believe that the scheme would benefit from a shorter qualifying period (two years instead of three years) and removal of the “minimum interruptions per year” requirement, instead focusing on the average/total number of interruptions over the period.

A further opportunity to improve uptake of the scheme is to remove the need for post-event checks which are burdensome and complex. These require a DNO-proposed percent reduction on the average number of interruptions for worst served customers over three full reporting years post-commissioning with scope for the DNO to provide evidence of the expected long-term benefit of the scheme if this is not achieved. We believe that removing these post-event checks would help to increase take up by reducing the funding risk for the DNO. Instead, DNOs should be required to report on the work undertaken and the performance improvements achieved and justify the investment if performance improvements are minimal or absent.

We believe that it is important that schemes undertaken demonstrate clear performance benefits for customers and, as such, we do not believe it would be in the interests of customers for the required level of performance improvement to be relaxed. However, we do believe that it would be appropriate to revisit the allowance per customer to ensure that it reflects current price levels, costs and the views of customers and stakeholders, allowing companies to target customer groups where the benefits of doing so are material and valued by customers.

Whilst we agree that inclusion of LV interruptions within the scheme is a valid objective in the longer term, we do not believe that the absence of LV interruptions is the reason for the scheme’s low take-up at present. As such, expanding the scope of the scheme to include LV interruptions at this time would distract from the changes needed to improve the scheme as currently scoped with resources diverted to data issues and recalibration. Once the current scheme is working as intended, expansion of its scope would be a logical next step to explore.

There may also be scope to consider funding schemes for worst served customers through ex-ante allowances, subject to them meeting the pre-defined criteria up front. Such an arrangement could be associated with a Price Control Deliverable to ensure the specified number of customer and/or schemes are delivered in the period, with immediate return of any unspent allowances. The design of any ex-ante funding may need to consider enabling the DNOs a degree of flexibility to respond to new issues that arise during the price control period rather than purely focussing on the worst served customers from a particular point in time. We would welcome dialogue as to whether this represents a viable route forwards and could address the concerns raised by Ofgem regarding the current RIIO-ED1 mechanism.

Indeed, a separate funding allowance for schemes, with a higher cost per customer, may be appropriate even if the main incentive scheme is retained. This additional approach would allow the very worst served customers to be specifically targeted by schemes that might otherwise be considered to be uneconomic, if the extremes of poor reliability experienced by certain customers are deemed to be socially unacceptable.

We do not think that it would be appropriate to fold the WSC regime into the IIS as this would introduce unnecessary complexity, and reduce the transparency of how DNOs are seeking to improve reliability for their worst served customers.

13. Maintain a safe and resilient network

OUTQ44. Do you have any views on our proposed NARM framework?

Within the Network Asset Risk Metric (NARM) framework for electricity distribution, Ofgem have a number of specific proposals, namely:

- Adoption of long-term risk;
- Commonality of reporting;
- Production of guidance document;
- Revision of methodology;
- Expansion of methodology;
- Incentives associated with NARM; and
- Use of NARM in Cost Benefit Analysis (CBAs) and Engineering Justification Papers.

Below we provide our views against each item in turn.

Adoption of long-term risk

We agree with Ofgem's desire to move to a longer-term measure of risk that better captures the true value of interventions along with more accurately reflecting the long-term benefits associated with different replacement and refurbishment activities.

We believe the most efficient way to achieve this is to build on the Common Network Asset Indices Methodology (CNAIM) that has been used during RIIO-ED1 as it provides a robust and consistent way to calculate the level of risk on the network. Whilst in RIIO-ED1 this generates risk at a point of time, adapting the framework to assign a typical 'cumulative discounted future Probability of Failure (PoF)' to each Health Index band represents a logical and pragmatic solution to Ofgem's desire for a longer-term measure of risk.

DNOs, through the ENA, have been collectively working with Ofgem's appropriate involvement on adapting CNAIM for this purpose. The consultation on these changes can be found here[11].

Commonality of reporting

We agree with Ofgem's desire for increased commonality of reporting across the 61 Asset Register Categories currently within scope of CNAIM. We also agree that it makes sense to provide a nil return for those assets a licensee does not own or operate.

Production of guidance document

We agree with the introduction of a guidance document that helps further drive consistency in inspection, assessment and reporting of condition inputs into the CNAIM modelling. We believe that the successful implementation of this document will negate the need for wholesale asset inspections audits. It does however need to be recognised that due to different inspection cycles on assets, it will take a number of years for the updated guidance, and thus greater consistency in reporting, to flow through the data inputs across a licensee's asset portfolios.

Revision of methodology

As stated by Ofgem it is a requirement of licensees under SLC 51 to keep the CNAIM methodology under constant review and we agree that if a material adjustment is required to update elements of the methodology within period then this should be fulfilled and accompanied by a rebasing of licensee targets if appropriate.

However, the key point to note here is the need to fix the 'look-up' values that underpin the safety, environmental, financial and network performance factors used to calculate the Consequence of Failure (CoF). By locking these down as soon as possible and ideally by the end of 2020 it will ensure the calculated value of risk used to build up companies asset management strategies will be consistent with those submitted to Ofgem in 2021. This is required to ensure companies can develop their planning and submit their initial and final business plans to Ofgem using accurate and representative numbers of risk. Waiting until after final business plan submission will result in

[11] https://www.energynetworks.org/news/publications/consultations-and-responses/

licensees having to rebase their targets before even starting the price control which if done prior to submission could have resulted the plan being different to the one submitted.

These values, once fixed should also be those used within business plan CBAs and Engineering Justification Papers for consistency.

Expansion of methodology

We understand Ofgem's desire to include an output/target across Non-NARM assets. We do not believe Option 2 or 3 as suggested within the SSMC are viable for implementation in RIIO-ED2, for the reasons outlined below:

- **Option 2, Notional Risk Weighting** – Whilst there could be merit in a framework like this, the practicalities of developing one that accurately captures appropriate values of risk for these Non-NARM assets is not achievable before the start of RIIO-ED2. Licensees are already developing their plans internally ahead of initial submission in summer 2021 and as a result there is simply not enough time to create reliable risk models that have been robustly tested with appropriate IT systems developed to support this implementation. Rushing this through without due consideration and testing runs the risk of inaccurately capturing the risk reduction associated by asset replacement and refurbishment activities. Furthermore, depending on the risk values associated with asset interventions it could cause unintended consequences/gaming of risk trading of assets between NARM and Non-NARM assets.
- **Option 3, Fault Rate Measure** – We agree with Ofgem's assessment of this option and believe this lagging output measure that is not directly linked to asset replacement or refurbishment expenditure, is not worth considering.

Instead, we believe **Option 1, Multi-asset Volume Driver**, or similar, is the most appropriate way to attach an output to Non-NARM assets and provide adequate protection to licensees and consumers.

We believe that the Non-NARM intervention volumes agreed by Ofgem in final determinations should have a set efficient baseline unit cost per asset per intervention with an ex-ante allowance to deliver these plans. Within period licensees are then free to deliver the plan or indeed amend their plan based on appropriate asset management and engineering decisions. At the end of the period, Ofgem can consider a licensee's delivery against the original plan, and if deviation from the plan is appropriately justified, Ofgem can adjust the final allowances using the agreed unit cost to ensure only justified delivered work is appropriately funded. Ofgem may consider the use of a deadband at an asset, voltage or network level to avoid regulatory burden for small differences in actuals verses planned volume delivery. An illustrative example is provided below:

Table 5: Volume Driver example

Final determination Values				Actuals Delivered			
Asset	**Volume**	**Unit Cost**	**Allowance**	**Actual Volume**	**Justified**	**Allowance Adjustment**	**Revised allowance**
Asset X	2,000	£15,000	£30m	2,200	Yes	+£3m	£33m
Asset Y	500	£120,000	£60m	400	Yes	-£12m	£48m
Asset Z	10,000	£7,500	£75m	10,100	No	£0	£75m
			£165m				**£156m**

Any under or overspend against the revised allowance would be subject to the Totex Incentive Mechanism (TIM).

Whilst the above option is the preferred option for use in RIIO-ED2, we would welcome the opportunity to work with Ofgem and others to consider the expansion of assets within CNAIM/NARM categories and indeed develop a reflective framework that allows the appropriate risk trading of assets between NARM and Non-NARM assets for implementation in RIIO-ED3.

Incentives associated with NARM

With regard to the incentive arrangements outlined in the SSMC at a high-level these can be summarised as per Table 6.

Table 6: Proposed NARM incentive arrangement

Delivery Scenarios		Proposed Approach
Over-delivery	Justified	Licensee to be made cost neutral.
	Unjustified	No funding adjustment.
On-target delivery	N/A	No funding adjustment.
Under-delivery	Justified	Unspent funding clawed-back.
	Unjustified	Unspent funding clawed-back. 2.5% Penalty applied.

We have no objections to these proposed over/under-delivery arrangements, the 2.5% penalty for unjustified under-delivery or the treatment of non-intervention risk movements.

However, Ofgem draw reference to the NARM Funding Adjustment and Penalty Mechanism Annex developed for the Transmission and Gas Distribution sectors in their draft determinations and it is within this document that we have concern. NARMs (or Networks Output Measures (NOMs) as it is known as in RIIO-ED1) are already very complex areas of the price control, but the proposals within this mechanism add significantly more complexity. This complexity is hard enough to explain within licensees let alone allowing external stakeholders the ability to adequately understand this area of regulation. A key priority of Ofgem at the start of RIIO-ED2 was to simplify the regulatory process where possible, but at present this element of the proposals not only fails at this but also significantly blunts the incentive for licensees to seek efficiencies or adapt their plans for the benefit of their networks and its customers.

It should also be noted that the framework used in RIIO-ED1 for monetised risk and its associated outputs are more advanced than that used in the transmission and gas RIIO-1 controls, therefore some of the problems and issues witnessed in those sectors have not been seen in electricity distribution. Furthermore, the changes proposed for CNAIM and the removal of the reward for an over-delivery scenario will deliver improvements and greater protection to both companies and their customers. Therefore, the very blunt and complex mechanistic proposals for the other sectors is not required nor applicable to electricity distribution.

That being said, we would like to draw reference to three specific areas within the NARM Transmission and Gas annex to provide additional justification as to why this framework is not applicable for RIIO-ED2.

<u>Justification for over and under-delivery</u>

The detail within the GD2 and T2 draft determination NARM annex points to a “high hurdle” for licensees wishing to justify an over or under delivery of their NARM targets. This high hurdle is missing from the language within the SSMC, and whilst the four justification principles are a useful clarification, the tone of language and risk of no additional funding or 2.5% penalty will only serve to dissuade licensees from deviating from their base plans.

The whole context of CNAIM and NARMs is to facilitate risk trading, i.e. to allow licensees’ asset replacement and refurbishment activities to flex in-period both to reflect the impact of forecasting intervention volumes over five years in advance as well as to enable licensees to react to new and emerging evidence within period. Yet this premise is undermined by putting such a high-evidence hurdle and consequential risk on the target, particularly given the suggested removal of any deadband.

Whilst every effort would be undertaken to deliver the target, due to the changing nature of the network and associated high-volumes of interventions it is not realistic to expect delivery to hit the target exactly. With the proposed removal of a deadband, licensees will always be required to justify deviation from target, even if the deviation is small – this process exposes licensees to unnecessary financial risk and both Ofgem and licensees to further regulatory burden for what could be a non-material difference in delivery. We note the reason for not having a deadband due to the proposed funding adjustment mechanism automatically amending allowances, but this automatic mechanism seems at odds with the manual and potentially laborious justification process.

We believe that Ofgem should move away from the onerous evidence hurdle implied in its language and instead use a more constructive tone, allowing a company ahead of time to flag where it feels it may be heading for a significant under/over-delivery. This way licensees can work with Ofgem ahead of time to clarify its position and

thus get confirmation ahead of the intervention(s) as to whether they would be deemed justified and limit the exposure of risk to licensees. Furthermore, whilst a deadband may not be required for financial adjustment, it may still be appropriate to consider a deadband for over/under justification such that licenses are not finding themselves having to provide significant evidence for small volumes of work in and around the target. This would also serve to reduce the regulatory burden placed upon Ofgem.

Efficiency Justification

Within this annex, Ofgem state that any underspend against planned interventions must be justified as genuine efficiencies if the licensee is to receive the TIM benefit of these works – we disagree with this proposal. This is a fundamental departure from output regulation and the incentivisation benefits of the RIIO regulatory model.

The significant business plan submission process, i.e. customer and stakeholder engagement, CEG and Consumer Challenge Group (CCG) challenge and Ofgem regulatory scrutiny and benchmarking determines efficient unit costs of interventions at the start of the control. It is the incentive properties of RIIO that drives licensees to look at its operations and establish how they can push the frontier of efficiency through each regulatory cycle and deliver its outputs for the lowest cost. This mechanism ultimately has benefits to both company and customers. We believe in this principle wholeheartedly and our management's desire and relentless drive to be the leading DNO at the lowest cost has led to £279m returned to customers in the first four years of RIIO-ED1 alone[12].

Ofgem's final determination is used to establish efficient unit costs, therefore requiring licensees to justify again at the end of the control what was efficient is an unnecessary step and will add significant licensee and regulatory burden. This TIM benefit should be afforded to both companies and customers as it does across other parts of the price control with any efficiency established during RIIO-ED2 baked in by Ofgem when it sets allowances for RIIO-ED3.

Funding Adjustment

We believe licensees should be funded for the work they deliver protecting both companies and customers from 'windfall gains or losses'. As stated earlier, the ability to risk trade and swap interventions out of the plan is a key component of the CNAIM and NARM frameworks and Ofgem is right to highlight how this ability could allow licensees the ability to deliver their targets for differing amounts of spend due to significant variances in the unit cost of asset interventions. However, the introduction of the proposed Delivery Adjustment Factor (DAF) is a blunt instrument that not only dissuades licensees from seeking efficiencies it also dissuades them from switching investment decisions even when it would be in the best interests of the network and its customers. It is also a further example of additional complexity to an already complex area.

We strongly believe that the TIM should be the vehicle for addressing efficiencies in the delivery of NARMs in RIIO-ED2. If however, Ofgem insist on proceeding with a DAF type mechanism then, Ofgem could simply adjust the allowances at the end of the control based on the intervention unit costs agreed at the start of the price control. This would address Ofgem's stated concerns by only funding the work that is undertaken by licenses yet still maintain the incentive to seek efficiency whilst delivering the programme of work that the network requires. However, this ultimately turns the NARMs framework into a volumetric measure and would appear to diminish the value of risk trading.

Use of NARM in justifying investment decisions

We note Ofgem's indication that they believe NARMs can be used as part of the toolkit to identify investment decisions but that it is not the only evidence required to justify interventions. We understand this stance as we believe the CNAIM and NARM frameworks are useful to quickly and with a good degree of accuracy portray the benefits of interventions. However, we believe that depending on the degree of benefits the NARM framework portrays in comparison to the cost of the intervention, this should guide the level of additional justification required. For example, if the NARM benefit of an intervention(s) is considerably larger than the cost of the intervention itself, additional justification could be at a minimum, whereas those whose benefits are on the fringe or even below – more detailed evidence should be required.

We believe Ofgem should set out the differing levels of justification required to reduce licensee and regulatory burden when producing CBAs and Engineering Justification Papers.

[12] https://www.ofgem.gov.uk/system/files/docs/2020/06/riio-ed1_supplementary_data_file_2018-19.xlsm

OUTQ45. Do you agree with our proposal not to introduce outputs or incentives related to workforce resilience?

We support the development of a workforce that has the skills to deliver the energy transition, reflecting the communities they serve. We believe that companies should therefore be supported through their allowances (not through outputs and incentives) to ensure they have a credible path in place to ensure they have a workforce with the right skills and that they reflect the communities they serve. Many utilities are facing significant challenges, both in replacing and recruiting a workforce fit for the future. This is particularly apparent in electricity as the way we manage and operate our networks is evolving. At UK Power Networks, our track record in this area demonstrates that keeping workforce resilience costs baked into allowances is the right thing to do to; the companies' management of their workforce is inherent to the successful running of the organisation.

Through the RIIO-ED1 period we have measured ourselves using a number of metrics designed to enhance the satisfaction, wellbeing (both physical and mental) and diversity of our employees. A couple of examples of success in these areas are:

- Reaching the Sunday Times Top 25 Best Big Companies to work for – for the third year running;
- Training over 200 Mental Health First Aiders in the company on a voluntary basis; and
- The reaccreditation of our National Equality Standard in 2020.

We will work with the other DNOs, our CEG and Trade Unions to share best practices and opportunities for consistency of reporting in this area during RIIO-ED2, but we are supportive of carrying over the same framework we had in RIIO-ED1 with no outputs or incentives.

OUTQ46. Do you agree with our proposal that DNOs should submit a Cyber Resilience IT Plan and a Cyber Resilience OT plan?

We do not agree with the proposal that DNOs should submit separate Cyber Resilience IT and OT Plans. We believe that DNOs should be allowed to submit a joint Cyber Resilience OT/IT plan to inform the setting of allowances for this are, as we believe this is more cost efficient. Should Ofgem accept this proposal, we would be happy to clarify our investments in the plan as IT only, OT only or joint IT and OT.

We have invested in cyber resilience for both IT and OT. We are currently following a consolidated approach where our cyber security policies and processes apply across the entire organisation to reflect IT and OT. We have also integrated cyber resilience as part of our wider organisational resilience strategy and tested it in an exercise run by the UK Cabinet Office. We found that this approach has proven beneficial for the acceptance of cyber security requirement by the business, as well as for security operations and governance.

From a price control perspective, a joint approach for IT and OT leads to cost optimisation by avoiding duplication of effort (for example, we use one central asset management system for both IT and OT assets). Moreover, the current technological evolution known as "IT/OT convergence" and the increase of Industrial IoT products go beyond the Purdue model by connecting OT directly to IT or the internet itself.

OUTQ47. Are there further requirements or expectations that we should be considering for the DNOs?

We believe that Ofgem's cyber resilience requirements of expectations are aligned with our understanding of the threat landscape, the current regulations and the future evolution of DNOs.

We believe that Ofgem's RIIO-2 Cyber Resilience Guidelines are helpful and contain the right level of detail. We are already following these as part of our RIIO-ED1 requirements and for NIS Directive compliance.

In summary, we do not believe that further requirements or expectations should be considered for DNOs.

OUTQ48. Do you agree with our proposal for the establishment of a 'climate resilience' taskforce or working group, to help DNOs develop strategies for managing the risks of climate change?

We agreed with the proposals set out and have no further comments to raise at this stage.

OUTQ49. How should DNO strategies inform best practice that is used across the industry? How can these be used to help DNOs develop longer term investment proposals to manage the risks of climate change?

The Climate Resilience Taskforce could develop a DNO Climate Change Engineering Technical Recommendation and/or good practice guide as during RIIO-ED2 in order to develop key performance indicators (and best practice) in this area by the time we must submit plans for RIIO-ED3.

OUTQ50. Do you agree with our proposal to retain the RIIO-ED1 approach to flood resilience?

We agreed with the proposals set out and have no further comments to raise at this stage.

OUTQ51. What are your views on how we/industry reports on progress against flood resilience plans?

We agree that an externally reported 'resilience metric' may be an effective way for the industry to communicate overall progress with Engineering Technical Report (ETR138). Any metric should reflect favourably on DNOs with strategies in place that also go beyond ETR138, such as protection of critical HV supplies (e.g. pumping stations), flood monitoring systems, regular flood risk reviews.

OUTQ52. Do you agree with our proposal to retain the RIIO-ED1 approach to ensuring networks are resilient to trees?

We broadly agree with Ofgem's proposal to retain the RIIO-ED1 approach to ensuring networks are resilient to trees. We have previously proposed to Ofgem that there may be merit in collecting information on the numbers of customers at risk from trees. In the RIIO-ED1 period we have used Light Detection and Ranging (LiDAR) to assist with targeting high risk spans affecting significant customer numbers and we continue to believe there is merit in exploring such risk based metrics.

However, we believe that clarification is required regarding reporting to ensure consistency across DNOs.

Our concern with the current method of reporting is that the guidance requires a whole feeder to be made resilient before ETR132 compliance can be reported. We have found that some resilience cutting is required – e.g. to assist in Forestry Commission harvesting, Ash Dieback and other legitimate reasons. These are carried out on a span basis and according to the guidance we cannot claim them. It is therefore possible that we would have incurred expenditure, but officially be unable to claim any achievement. Whilst it is recognised that we cannot claim achievement against the amount of network made compliant (and count this towards the target of 20% compliance), we should still be able to claim achievement for work carried out. Also, the reporting requirement in the Regulatory Instructions and Guidance (RIGs) for length (in km) of network to be made compliant does not necessarily fit with the best interest of the network or customers. It may be that the critical feeders with the highest numbers of customers impacted are on short lengths of overhead network. So a requirement for the 'length of network made compliant' may not be the best approach, or most cost effective. Our proposal would be to report on 'proportion of network made compliant' on a feeder or circuit basis. Finally we would suggest to change the units for ETR132 reporting to spans instead of km to be consistent with ENATS43-8 cutting.

OUTQ53. Do you agree with our proposal to develop a wider resilience measure over the course of RIIO-ED2? If so, what should it cover?

We agree that a wider resilience measure would be helpful, especially for ensuring long term investment approaches for important areas of activity, including tree cutting and flooding.

The wider resilience measure approach could also be used to fill the gap between expanding the NARMs approach to Non-NARMS asset categories[13]. This could, for example, include elements relating to: Civil Substations resilience; Climate resiliency (e.g. heat impacts on equipment operation); telecommunications; and, the level of network redundancy to cater for High Impact Low Probability events.

OUTQ54. Do you agree with our proposed approach of retaining the existing arrangements for Black Start, physical security, and telecommunications resilience?

We broadly agree with the proposed approach. Black start requirements could become more onerous in future in which case DNOs would need the facility of a re-opener to address any material changes in expenditure requirements. Additionally, given that the public switched telephone network (PSTN) is being phased out by 2025, funding will be

[13] Paras 8.51 to 8.56, p.116 of SSMC Annex 1 – Delivering value for money services for consumers.

required to deploy replacements to ensure resilience in network management (SCADA, substation telephones and monitoring systems). This PSTN switch-off may impact customers and work is underway via the ENA to further understand this. As such, until a clearer picture is available, a telecommunications reopener should not be ruled out at this stage.

OUTQ55. Do you agree with our proposal to include a re-opener for physical site security, with a window during the price control and a window at the end of the price control?

We agree with the proposals set out such that, if there were further CNI requirements mandated during the period DNOs would need a re-opener to address material changes in expenditure requirements and have no further comments to raise at this stage.

OUTQ56. Do you agree with our proposal to continue monitoring the development of telecommunications resilience and reviewing the arrangements as necessary?

We agree with Ofgem's proposals.

UK Power Networks has been at the forefront of developing and operating resilient, secure, cost-effective and flexible telecommunications networks.

Our move and standardisation to Internet Protocol technology for all Supervisory Control and Data Acquisition (SCADA) communications across all voltage levels has allowed to utilise a mix of the most suitable commercially available technologies and deliver benefits for consumers and connectees. The move to Net Zero will require increase in resiliency, security and capability of the telecommunications networks as highlighted with Ofgem.

We are monitoring a number of developments that are relevant to our ED2 submission:

- We have been working as part of ENA to understand the feasibility of a resilient radio comms network utilising industry agreed spectrum, as highlighted in the SSMC. We have carried out own independent studies in understanding the potential of such network.
- In addition, we are in discussion with BT and other providers to understand their future communications offerings.
- Our digital substation programme will bring forward proposals to add local intelligence into substations to deliver increased functionality at lower cost
- Finally, over DCPR5 and RIIO-ED1 we have invested in developing fibre networks. We will look to further enhance and optimise that capability over RIIO-ED2.

14. Delivering an environmentally sustainable network

OUTQ57. Do you think our proposed environmental framework will drive DNOs to deliver an environmentally sustainable network?

The framework has many good elements. Ofgem is rightly calling for ambitious proposals for environmental improvement and achievement of Net Zero goals. It has emphasised the need for transparency of strategies, actions and outcomes and reporting by companies of their progress towards measurable goals. These are good objectives which we support. The proposed common environmental framework has many good features with which we agree, particularly:

- The requirement for an Environmental Action Plan (EAP) encompassing all aspects of a companies' strategy to deliver decarbonisation and a sustainable environmental impact;
- Clear indicators and targets consistent with the path to Net Zero with the need for alignment to Science Based Targets;
- The expectation that environmental considerations are embedded into decisions on network investment and other operational activities;
- The requirement for an Annual Environmental Report to secure accountability for delivery; and
- The need for engagement with customers and stakeholders in setting and reporting on companies' ambition, strategies, and actions.

However, Ofgem have proposed not to introduce a financial incentive for companies to act to meet decarbonisation and environmental ambitions within the RIIO-ED2 period.

A core feature of the RIIO regulatory framework is a package of incentives which reflect the priorities of customers. Since RIIO-ED1 was established, there have been many developments which are indicative of the importance society places on protecting our environment. To name a few:

- Legislation passed for the UK to achieve Net-zero carbon emissions by 2050;
- Ban of the sale of Internal Combustion Engine vehicles by 2040 at the latest;
- Climate Assembly UK established;
- Plastic carrier bag charge introduced; and
- Focus on Persistent Organic Pollutants.

In addition to this, our engagement with customers and stakeholders to date clearly demonstrates the importance they attach to companies acting to address decarbonisation and environmental concerns. We intend to explore this in more depth in our future phases of RIIO-ED2 engagement.

With all this evidence of the priority our customers place on environmental concerns, we are surprised that Ofgem's proposals for the incentive framework in RIIO-ED2, as established through Output Delivery Incentives (ODIs), has a conspicuous gap in this area.

We note that Ofgem's Draft Determination for National Grid Transmission, included a bespoke environmental incentive along similar lines to those we have proposed (see below). In Ofgem's determination, it states that this incentive will ensure the company has a financial interest, proportionate with its involvement and effort, in achieving or exceeding the RIIO-2 targets set out in its EAP. We do not see why these principles would not also apply to electricity distribution.

We have strong environmental credentials and a clear vision for the central and critical role of DNOs in securing Great Britain's ambitions which we set out in our response to Ofgem's 2019 Open Letter[14]. In this letter we also highlighted the potential for incentives to support these ambitions. Incentive schemes using common performance metrics have been proven to lead to customer benefits as companies strive for best practice. RIIO-ED2 can build on this by defining that focus on facilitating and achieving low carbon networks.

Well-designed incentives provide a level of focus through the business which supports innovation and action which can be directly linked to and measured against customer support. They encourage licensees to make crucial investment required to deliver innovative solutions and secure delivery of the desirable outcomes for customers. Common incentives can drive competition between licensees which will drive up standards for all and reveal

[14] Letter from Basil Scarsella, UK Power Networks to Steven McMahon, Ofgem, 22 May 2019.

innovative ideas and strategies. They provide the impetus to go beyond what is known and predictable at the outset of a price control: to seek new ideas and make them work. Finally, the process of creating and operating an incentive regime provides focus and stimulus to the task of making measurement and reporting consistent and comparable. A balanced combination of financial and reputational incentives working at transactional and strategic levels should result in achieving the best possible outcomes for customers: the Broad Measure of Customer Service is just one compelling example. We think that they have a key role in delivering this critical element of licensees' activities. Given the significance of the DNOs' contribution and influence over environmental improvement and achieving Net Zero in the eyes of our customers, it seems an oversight not to include appropriately calibrated incentive arrangements for outcomes in this area.

Proposals for workable new incentives

Clearly incentives need to be well designed. We have already proposed two new incentives, the Environmental Performance Incentive (EPI) and the Environmental Quality Assessment Measure (EQAM) which we have discussed in the RIIO-ED2 working groups.

The EPI focusses on the reduction of carbon emissions which are wholly or partially within companies' control and is designed to encourage companies to secure the best way of reducing carbon emissions across all activities impacting carbon emissions including: Business Carbon Footprint, Losses, Fluid Filled Cables, and potentially connection of LCTs.

The EQAM focusses on other environmental impacts which are harder to measure. It proposes the construction of an index which can be used to measure and encourage overall performance.

We believe that incentives like these are essential to drive performance. Further work will be needed on design and calibration but that is achievable and is supported by Ofgem's desire to establish common metrics through the continued work of the Decarbonisation and Environmental Working Group. Critically, customers are impacted by incentives through their bills as well as benefitting from the resulting outcomes. It is therefore essential that incentives are calibrated taking into account of customer views and obtaining these views is a key part of our proposed customer engagement programme.

Ofgem's concerns about the use of financial incentives

Ofgem highlights several reasons for rejecting the use of financial incentives. However, we believe that these concerns are either misplaced or could be overcome.

The concern that a financial incentive will skew activities towards one outcome at the expense of another needs to be considered. However, this is the case for all incentives in the regulatory framework and the proven success of incentive based regulation to date shows that with appropriate calibration, this concern is unfounded. In fact, the bigger risk is that lack of incentives for environmental improvement skews companies' focus away from critical environmental goals. In addition, the incentives we propose specifically tackle this issue at a lower level. We agree it is better to have incentive mechanisms which allow companies to balance their actions to reduce carbon and which allow trade-offs to be captured. Our proposals for an EPI are better than separate incentives which address some individual elements such as SF6. The EPI could also be designed to include other wider impacts on carbon emissions such as the connection of LCTs to cater for interactions with areas such as network losses.

The impact of DNOs' activities may be difficult to measure. This is true but reputational incentives such as the combination of the EAP and Environmental Assessment Report (EAR) rely equally on effective measurement and this is not a reason to reject a financial incentive. As we suggest above, creating and implementing measurements is a strong driver to achieving the effective measurement that would be required for reputational incentives.

Ofgem has highlighted that it may be complex for incentive arrangements to accommodate regional variations in approaches to Net Zero. In respect of carbon emissions this seems a highly flawed perspective: it does not matter where carbon reduction comes from in achieving Net Zero as atmospheric carbon is a global common issue. In fact, a financial incentive would help focus on the question of which activities in which regions and areas provide the most effective level of carbon reduction, i.e. the most effective use of customers' money. For other environmental impacts there is clearly a regional dimension. We recognise that but consider that careful design of the EQAM index and targets involving regional stakeholders can overcome this. In either case the impact of the incentive will be to highlight necessary focus on regional variation.

The potential for windfall gains and losses does need to be considered and is a risk with all incentive mechanisms. However, we believe that our proposals can deal effectively with impacts which are not wholly within our control if well designed. For example, the use of well-calibrated caps and collars on individual incentives and the overarching Return Adjusted Mechanisms (RAM) approach will provide such protection. We agree that it is important that this matter is clear to our customers and stakeholders.

Incremental expenditure

Ofgem has indicated it does not expect to see substantial increases in baseline allowances for activities relating to delivery of EAPs. Clearly any spend proposals need to be justified by the benefits accruing to customers and society as a whole and it is welcome that Ofgem will consider the case for them. We understand that it is not "ruling out" incremental spend in this area although it seems premature to presuppose the outcome of this. Well-designed price control arrangements are a way of dealing with the need to provide funding to uncertain expenditure.

OUTQ58. Do you consider that the proposed areas in scope of the Environmental Action Plan, and associated baseline standards, are appropriate? We particularly welcome views on any areas that should be omitted/included and if new areas should be included, what the baseline standard should be?

We consider the proposed scope of the EAP to be appropriate. It covers all of the areas that we would expect to see and acknowledge that the proposed approach allows DNOs to put forward plans in other areas as they see appropriate with support of customers and stakeholders. We agree that the baseline standards set out in Appendix 3 of the Business Plan Guidance are appropriate in their intent, however clarity in some areas may be beneficial for the purposes of assessment under the BPI.

Further work will be required by all licensees to specify the standards in more detail and we are committed to the efforts to achieve this through the Decarbonisation and Environmental Working Group.

OUTQ59. Do you agree that the annual reporting through the Environmental Impact Report will increase transparency of the DNOs' activities and the resulting impacts on the environment?

We agree that a published annual report should increase transparency of DNOs' activities and environmental impact and should therefore enable stakeholders to hold DNOs' accountable for environmental outcomes.

The power of such reporting as a tool for accountability and driver towards good outcomes will be immensely enhanced by commonality of measurement and method across DNOs' reports. Without it there is a risk it will just be too difficult for stakeholders, even engaged ones, to compare and contrast approaches and performance. The industry recognises this and there is work underway through the Decarbonisation and Environmental Working Group to achieve this.

As we have stated above, implementing financial incentives would be a strong driver towards achieving common measurement.

OUTQ60. Do you agree with our proposal to introduce a re-opener to accommodate environmental legislative change within the RIIO-ED2 period?

The SSMC is right to highlight the potential for changes to environmental legislation to have a material impact over RIIO-ED2. We therefore agree that it is appropriate to include a re-opener to deal effectively with this uncertainty and that it is reasonable to expect companies to work together in the event that there is a need to use it. The specific potential change to SF6 regulations is a material risk and may be implemented with retrospective effect and we welcome Ofgem's recognition of this.

We agree this re-opener is best suited for distinct changes to environmental legislation. We note that the SSMC seeks to define its scope as legislation which effect "how the activities within the scope of the EAP are delivered." While we agree that this is likely to capture most of the impact foreseeable environmental change, it is possible that this phrase may be interpreted too narrowly. It could be that there is future change in environmental legislation which affects something not covered by the EAP or which has a material impact beyond "how activities are delivered". It would be useful if Ofgem should clarify whether it sees any restrictions in the scope of this re-opener applying and if so, what they are.

OUTQ61. Do you agree with our proposed removal of the Losses Discretionary Reward?

Losses are major cause of carbon emissions resulting from the activities of DNOs. While the extent of losses are not fully controllable by DNOs they can contribute substantially to reducing them and are increasingly able to understand what causes losses and therefore discover and implement new ways of reducing them and hence lower carbon emissions and energy costs. Ofgem rightly points out that much progress has been made by the companies over RIIO-ED1.

The Losses Discretionary Reward (LDR) has contributed to driving the improvement in knowledge and understanding that has been seen over RIIO-ED1. It is a direct financial incentive which targets an important activity and companies have responded. The SSMC points out some of the positive impacts such as the establishment of the Technical Losses Task Group and the promotion of cost benefit analysis in undertaking proposals. The LDR has had a positive impact in this area however, there is much still to be done and it is very likely that this will need both increasing levels of collaboration and investment in research and implementation.

Given this, the removal of any financial incentive to manage losses is concerning. As we set out in response to OUTQ57 we believe that there should be some financial incentive to reduce losses within the wider context of incentivising DNOs' environmental impact.

Our current proposal for an EPI covers losses and it therefore directly relates the incentive to measurable loss reduction rather than an ex-post qualitative assessment of companies' plans, actions and progress. This form of incentive would help to tackle the two problems that Ofgem highlight as it would be less burdensome to operate and would provide a strong focus and drive for commonality. Companies will be strongly incentivised to make sure that measurement is fair, comparable and robust.

The key role of research and innovation in tackling losses will generate long-term benefit across the industry. Some of the work we have done during RIIO-ED1 led to new knowledge about losses behaviour. Given the route to securing material reduction in transmission losses is likely to involve genuine innovation, we also urge Ofgem to consider whether innovation funding might be used specifically for work on losses.

OUTQ62. Do you agree with our proposal to retain the visual impact allowance for RIIO-ED2?

While it is true that to date only a relatively small proportion of the overall funding pot for RIIO-ED1 has been spent across DNOs, we agree that the mechanism has been effective. Clearly it is hugely important that the views of stakeholders that are anxious to safeguard the appearance of National Parks and AONBs are taken into account and the mechanism provides a good way of ensuring these concerns are balanced against the cost for customers of undergrounding schemes.

We therefore support retaining the visual impact allowance.

OUTQ63. Do you agree with our proposed approach to setting a funding pot for the visual impact allowance for RIIO-ED2?

We agree with the funding pot approach and support Ofgem's consideration of Willingness to Pay (WTP) studies in setting its overall size and allocation. The proposed allocation method, as described in the SSMC which was used for RIIO-ED1 appears reasonable and would welcome confirmation of the respective DNO use-it or lose it allowances for RIIO-ED2 in the SSMD. We believe this will enable licensees and their stakeholders to mobilise early and make more effective use of allowances in RIIO-ED2.

Whilst it may be appropriate to transfer the benefits of the studies conducted for electricity transmission, but we would urge a careful consideration of the validity of such a route in its applicability to the circumstances of the distribution sector.

We agree that companies should be asked to set out potential example projects in their business plan submissions and to publish their approaches to assessment of potential schemes to provide clarity for stakeholders. However, we believe this should continue to be a dynamically stakeholder-led mechanism which could result in a different portfolio of schemes being delivered within the RIIO-ED2 period. As such there may be merit in focussing this dialogue on ensuring licensees and stakeholders work collaboratively both ahead of and during RIIO-ED2 to make maximum use of the mechanism, rather than attempting to shoehorn all of this engagement into the circa fourteen months before submission of final RIIO-ED2 business plans.

QUESTIONS IN SSMC ANNEX 2 – KEEPING BILLS LOW FOR CONSUMERS

15. Approach to Aggregated Econometric Analysis

COQ1. Do you agree with our proposal to include totex benchmarking in our toolbox for cost assessment in RIIO-ED2?

We support the use of totex modelling as part of the cost assessment, because it allows Ofgem to fully consider the diverse range of ways in which companies can minimise their expenditure in innovative ways, which may be incorrectly identified as inefficient in disaggregated models.

For instance, delivering lower volumes of work with high unit costs could be beneficial if the activities selected have a large customer benefit or substitute for a large volume of cheaper work. Such measures to maximise efficiency while delivering customer outputs may appear as inefficient under some disaggregated modelling approaches.

As a tangible example of this, Ofgem's disaggregated tree cutting model at RIIO-ED1 explains efficient tree cutting expenditure using spans cut and spans inspected as cost drivers in an econometric model. However, in RIIO-ED1, we have reduced our volume of tree cutting, since we developed new working practices and inspection techniques that allow us to better identify lengths of overhead line which are most susceptible to tree damage, and most likely to cause customer supply interruptions if they fail following tree damage. A disaggregated benchmarking model relying on workload drivers is less able to identify the relationship between efficient costs and outcomes than a top-down model which is able to control for customer outcomes.

As well as providing a more comprehensive assessment of DNOs' relative efficiency, some of Ofgem's RIIO-ED1 disaggregated models appear to have significant limitations. As described below in more detail, some fail to explain the vast majority of variation in DNOs' costs, suggesting these methods lack statistical robustness, and variation in DNOs' performance reflect differences in data reporting practices, network configuration or condition, or operating environment, not differences in efficiency across companies.

However, while we consider that totex modelling should provide a core part of Ofgem's cost assessment and performs better than disaggregated modelling when assessed against standard statistical tests and model selection criteria, Ofgem should recognise its limitations. In particular, totex models linked to high-level drivers of scale like Modern Equivalent Asset Value (MEAV) will not control adequately for the increases in expenditure that may be needed to deliver Net Zero, or deliver enhanced outcomes for customers. These will need to be assessed outside of the core totex modelling.

Also, the forms of totex models used by Ofgem in the past also have a limited ability to capture differences between the operating environments of different DNOs, including environmental factors (urbanity/sparsity), regional wages, asset conditions, levels of network loading/utilisation. Off-model adjustments would be needed to ensure the levels of allowed totex are set at a level that reflects these factors. Ofgem may also need to consider a more diverse set of totex models at RIIO-ED2.

We have developed benchmarking evidence to update the RIIO-ED1 benchmarking models, examine their performance and suitability for setting RIIO-ED2 allowances, and develop potential improvements. In particular, we provide further analysis on our update of the RIIO-ED1 totex model and our work to identify potential improvements to it in response to COQ2 below. We have also updated the RIIO-ED1 disaggregated models for most categories of expenditure, as discussed in response to COQ27 to COQ31.

COQ2. What cost drivers do you consider appropriate for our proposed totex benchmarking? Why?

Ofgem should consider a range of model specifications. While we consider it is appropriate to include totex modelling in Ofgem's toolkit, it is important to recognise its limitations and that no totex model will produce an undisputable "true" assessment of DNOs' relative efficiency

Any statistical model is only as good as the data used to populate it, and any one regression model will only be able to consider a small number of drivers because of the small number of comparators (14 DNOs, six groups). Hence, there is a risk that in any one model conflates omitted factors, data error and differences in efficiency.

One way to address this limitation is to consider a number of different totex model specifications, and assess the sensitivity of modelled efficiency gaps or forecast costs to changes in the model. Setting allowances based on a single totex regression model (or a small number of very similar models) could result in allowances exhibiting a

false degree of precision. We propose that Ofgem should acknowledge the limitations of comparative benchmarking, and consider the sensitivity of its results to alternative methods when setting allowances.

UK Power Networks appears to be the most efficient DNO using Ofgem's RIIO-ED1 totex model and updated data from the RIIO-ED1 period

For RIIO-ED1, the top-down totex model included a Composite Scale Variable (CSV) combining MEAV and customer numbers as a driver, plus a time trend. Ofgem estimated this model on actual and forecast data (2011-2023) from the RIIO-ED1 BPDTs. The weightings within the CSV variable were the result of a separate regression analysis: the weight on MEAV was 87.8% with a 12.2% weight on customer numbers. Over the first four years of RIIO-ED1 to 2018/19, the model used by Ofgem at the RIIO-ED1 review showed our business plan forecasts ranked between 8th and 12th across our licensees, or 5th at a group level.

We have updated Ofgem's RIIO-ED1 top-down totex model with the latest available data from the RIIO-ED1 period. Our update of the RIIO-ED1 top-down totex modelling shows we rank first amongst the six DNO groups.

While the updated model fails the White test for heteroskedasticity, this is not a serious problem as we use "robust" standard errors. At the same time, the model passes the Chow test for structural change between the RIIO-ED1 and DPCR5 control periods, the Reset test (an important test for mis-specification of the functional form) and the normality test.

Ofgem should nevertheless consider additional variables to improve the totex model

Even though Ofgem's updated RIIO-ED1 model results in a positive outcome for UK Power Networks, we are aware of a number of limitations to Ofgem's RIIO-ED1 model. We therefore consider it appropriate for Ofgem to consider a range of different drivers, including scale drivers (e.g. MEAV, customer numbers, peak demand), and environmental factors (e.g. sparsity, density, Gini coefficient). It may also be appropriate to consider other factors, such as network condition.

In addition to those drivers considered in Ofgem's RIIO-ED1 totex models, we have considered a number of cost drivers that could potentially improve the performance of the top-down totex model, or at least result in a credible alternative model. As summarised in Table 7 these drivers control for scale, customers served and other environmental factors.

Table 7: List of cost driver candidates for RIIO-ED2 top-down totex model

Candidate Drivers	Relevance for totex modelling	Under DNO Control
MACRO CSV	• It reflects the scale and the composition of the network, but differences in MEAV may not reflect differences in the scale of Closely Associated Indirect (CAI) activity, e.g. underground unit costs are several times higher, but may not be driving up CAI costs	Only in the very long term
RIIO-ED1 BU CSV	• This is a composite scale variable representing the disaggregated activity level analysis drivers (comprised of units distributed, total network length, LV and HV overhead line length, MEAV, customer numbers, spans cut, total faults, and total ONIs)	Some of the drivers under DNO control (e.g. spans cut)
MEAV	• It reflects the scale and the composition of the network, but differences in MEAV may not reflect differences in the scale of CAI activity, e.g. underground unit costs are several times higher, but may not be driving up CAI costs • MEAV only captures CAI associated with capital activities, i.e. adding assets, not operational activities like using flexibility contracts with DES providers • Does not capture many environmental factors (e.g. London effects) causing the same asset to be more complicated to operate in different conditions • Data revisions during RIIO-ED2 suggest the asset register is not entirely accurate	Only in the very long term

Candidate Drivers	Relevance for totex modelling	Under DNO Control
MEAV UG and MEAV OH included separately	• These two variables de-compose MEAV into Underground MEAV assets and all other assets ("MEAV OH") to better capture the potential impact of UG assets on CAI • These drivers suffer from the same limitation cited for MEAV	Only in the very long term
Number of Customers, Network Length, Peak Demand	• All three variables are alternative scale variable to MEAV, and may be avoiding some of the possible distortions associated with MEAV (e.g. OH vs UG) • Unlike MEAV, however, they fail to capture the complexity and composition of DNOs' assets (e.g., complexity associated with rural verses urban networks)	Only in the very long term
Density	• Density is defined as the number of customers per square kilometre of network area; it measures how densely populated an area is • It is a driver of multiple cost categories, including network and planning costs as per Core CAI regressions	No
Gini Index	• Captures the variability of customer density within an area and how this impacts on a number of cost areas	No

Ofgem should consider the merits of alternative model specifications

Using these variables, we have identified a number of possible alternative models that Ofgem may wish to consider for consider using at RIIO-ED2.

- **Model 1** tests the implication of using MEAV and the number of customers as two separate drivers, instead of relying on the CSV variable. The coefficient on customer numbers is not significant, suggesting that the CSV in the RIIO-ED1 update is driven by MEAV, but this may also reflect the high correlation between MEAV and the number of customers. Between 2011-2019, we find the correlation coefficient between these drivers is 0.95.
- **In Model 2**, we considered splitting MEAV into overhead and underground components, as differences in the "modern equivalent" value of these assets may not reflect differences in the amount of totex required to operate and maintain underground/overhead networks. Both coefficients on UG/OH MEAV are significant and the model passes all diagnostic tests. But because this model only controls for MEAV, it may fail to capture other drivers of costs associated with workload and environmental factors.
- **In Model 3** we tested a model using network length alongside MEAV. The result shows that network length is not significant, possibly because MEAV already captures network length to some extent.
- **In Model 4** we use network length (to control for the footprint of the network) combined with customer numbers (to control for demand), without relying on MEAV which as noted above has some significant limitations. Both coefficients on customers and network length are significant and with intuitive signs and magnitudes. This may be a potential candidate model for RIIO-ED2, but may be improved by adding environmental factors.
- Thus, **in Model 5**, our favoured model, we added variables to Model 4 to better control for environmental conditions, i.e. combining length and customer numbers with density and "Gini" coefficient (a measure of dispersion). In this model we also removed the company-specific adjustments for LPN and Scottish Hydro Electric Power Distribution (SSEH) to avoid double counting the adjustments for sparsity and density. Model 5 avoids the unreliable MEAV variable, instead using two simpler measures of scale (i.e. length and customers). It avoids linking allowed totex to the size of network assets, accounting for the fact that DNOs may (efficiently) use more DERs in the future while still serving the same (or increasing) demand. By controlling for density and Gini, the model does not need separate (potentially subjective) adjustments for regional factors for density/sparsity.

At this point in time, whilst we have identified a "preferred" totex model in terms of robustness and statistical properties, we are not advocating for any one of these models. Rather, we suggest Ofgem considers a range of alternative specifications to improve the regulatory process by reducing the risk that allowances are distorted by relying on the results of any one model.

If the quality of the data allows, it may be also possible to improve the totex models further, by accounting for network characteristics that affect the efficient level of totex, such as asset condition, level of network loading, etc, or the levels of output provided to customers such as quality of supply and customer service.

For instance, to comprehensively assess DNOs' overall efficiency, ideally Ofgem would net off the value of output improvements licensees have delivered before assessing whether their levels of expenditure are efficient. This could be done either using quality or output metrics as explanatory factors in the regression, or by modelling "net totex" as the dependent variable in a regression, i.e. multiplying the societal value by the change in outputs delivered, and subtracting from totex before running a regression. However, under either approach, Ofgem would need to exercise care in using the modelling results to set forward-looking allowances.

However, recognising the challenges of ensuring such data is comparable, and the limited number of cross-sectional observations Ofgem has available to estimate totex models, it may be necessary to control for some of these factors through other methods, outside of the totex regression models.

COQ3. What are your views on the use of both historical and forecast data in our modelling?

There are advantages and disadvantages associated with using historical and forecast data in Ofgem's comparative benchmarking.

Using historical data allows Ofgem to estimate coefficients in a way that captures historically observed interactions between costs and drivers, whereas using forecasts may "pollute" the estimated regression coefficients with the relationships between costs and drivers assumed by companies when developing their business plans. The use of "smoothed" or extrapolated trend data in the forecast period could also create econometric problems, such as multicollinearity between alternative drivers, and spurious relationships between different drivers that all follow upward trends.

On the other hand, if the relationship between drivers and costs is likely to change in the future, using forecast data in regression equations could reveal structural changes in the factors driving DNOs' expenditure requirements during the RIIO-ED2 period.

Our analysis on tree cutting demonstrates that relying on business plan forecasts to estimate econometric relationships between costs and drivers may lead to inaccurate results. While we use tree cutting as an example, the problems we highlight could equally apply to other cost categories. At the same time, if there are reasons to think the relationships between costs and drivers are likely to change in the forecast period (i.e. as compared to the historical period), then relying on forecast data may be necessary.

Ofgem could test whether it is appropriate to include historical and forecast costs together in the same model using a Chow Test, for instance. However, estimating econometric relationships using forecast data will be more challenging than at RIIO-ED1, as Ofgem will only have five years of cost forecast data for RIIO-ED2 rather than eight.

Using regressions estimated using historical data to forecast ED2 costs

If Ofgem concludes that forecast data should *not* be used for the estimation of regression equations, it could still use regression coefficients obtained with historical data to generate predicted values over the RIIO-ED2 period using projections of relevant drivers. This is similar to the approach taken by Ofwat at PR19 to apply its econometric models (estimated using historical data) to set allowances.

To illustrate the effect of applying this approach to forecasting RIIO-ED2 allowances, we have used our preferred totex model which uses customer numbers, network length, density and the Gini coefficient as drivers, to forecast costs into the RIIO-ED2 control period. This approach could lead to costs across the industry which are, based on the data available at this point in time, circa 7 per cent lower during RIIO-ED2 than during RIIO-ED1.

In fact, this approach to forecasting RIIO-ED2 allowances leads to allowances which reflect a continuation of long-term downward trends in DNOs' expenditure. Expenditure in DPCR5 was at a high point for many companies, while several of the key drivers (network length, customer numbers, MEAV, etc) have trended upwards. These historical downward trends will be reflected in lower slope coefficients on the upward-trending drivers, and a negative coefficient on the time variable.

While approaches based on historical data could be used to forecast DNOs' "business as usual" expenditures, they do not reflect the increase in expenditure needed for DNOs to take on new activities and invest to support the

transition to Net Zero. The factors driving the need for these increases in expenditure are not reflected in the drivers that can credibly be included in totex models. Put differently, the drivers in the model do not capture the need for accelerated expenditure required for DNOs to support Net Zero.

If trends in historical costs are unrepresentative of future drivers of cost and the drivers will not reflect the need for accelerated expenditure, this approach may not grant companies sufficient RIIO-ED2 allowances, unless Ofgem makes separate off-model adjustments. We discuss ways of assessing the possible increase in DNOs' expenditure during RIIO-ED2 in response to COQ21.

COQ4. At what level should we set the efficiency benchmark?

There is no analytical basis for identifying the "correct" efficiency benchmark. We consider that it is important Ofgem sets out precisely the considerations and criteria it follows when setting the target, explains how it arrives at its eventual decision, and considers regulatory precedent when doing so.

At past price control reviews, Ofgem has set the level of efficiency target by making a trade-off between the risk of data error, omitted factors, and imprecision of its econometric models resulting in infeasible cost targets, against the desire to set a stretching efficiency target for the industry. This has led it to set a target at the upper quartile (75th percentile) level of performance, balancing these considerations at most past reviews.

In the RIIO-GD2 Draft Determination, Ofgem has proposed to set a more demanding target at the 85th percentile, citing improvements in data and a more robust model. This target is a more demanding efficiency target than used in any recent price review in UK regulated industries. For example, in its redetermination of Bristol Water's PR14 price control, the CMA found that Ofwat's modelling was not robust enough to set an upper-quartile benchmark, and so applied a cost target based on the median company:[15]

> "Besides Ofwat's approach to PR14, there is regulatory precedent from Ofgem, as well as the CC's Northern Ireland Electricity price determination in 2014, for an approach that sets price control expenditure allowances on a basis that requires a greater level of efficiency than industry-average efficiency. Ofwat's PR14 price control framework, including its approach to the cost of capital, was developed in this context. The regulatory precedent from Ofgem and the CC has also recognised that a less demanding benchmark than the upper quartile may be appropriate in cases where there was less confidence in the modelling results. The effect of modelling error and limitations will tend to mean that an upper quartile benchmark will require levels of efficiency that are, in practice, greater than the upper quartile."
>
> "We were concerned that an efficiency benchmark based on an upper quartile efficiency concept would be overly demanding if applied to the results of the econometric models that we used. This was a judgment in the light of the issues we had identified both from our review of Ofwat's econometric models and from our development of alternative models".

Ofgem has itself acknowledged that the efficiency benchmark should be set based on the reliability of the benchmarking model. For RIIO-GD1, Ofgem justified the choice of the upper quartile rather than the frontier by the imperfection of its statistical models:[16]

> "We defined efficient costs equal to the upper quartile (UQ) Gas Distribution Networks (GDNs) costs rather than the frontier allowing for other factors that may influence the companies' costs. We also assumed that GDNs would close only 75 per cent of the assessed gap between their forecasts and the UQ. The use of the UQ is identical to previous price reviews (e.g. GDPCR1, and more recently the electricity distribution price review, DPCR5). Our proposed approach to closing the gap and the use of the UQ rather than the frontier acknowledges that a part of the difference in costs across the GDNs relates to factors other than GDNs' relative efficiency (e.g. statistical errors)."

For RIIO-GD2, Ofgem acknowledges in a technical annex that the choice of efficiency benchmark should account for the fact that part of the difference in modelled costs relates to factors other than relative efficiency.[17] Despite this, Ofgem only briefly alludes to the reliability of its modelling in its justification for its proposed benchmark:[18]

[15] CMA (6 October 2015), Bristol Water plc: A reference under section 12(3)(a) of the Water Industry Act 1991 Report, para 4.221, 4.222, and 4.224.
[16] Ofgem (17 December 2012), RIIO-GD1: Final Proposals – Supporting Document – Cost Efficiency, p. 7.
[17] Ofgem (9 July 2020), RIIO-GD2: Step-by-Step Guide to Cost Assessment, p. 3.
[18] Ofgem (30 July 2020), RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, p. 18.

> "Similar to RIIO-ED1, in RIIO-GD1 the efficiency benchmark was set at the UQ. Justification for changing this approach in RIIO-GD2 to the 85th percentile centred on sector wide outperformance of cost allowances throughout RIIO-GD1, and the better data, and improved robustness in modelling available in RIIO-GD2."[19]

This passage does not amount to a substantive assessment of its model, as it does not assess the statistical properties of Ofgem's model or the reliability of data.

This approach of setting the efficiency threshold with reference to historical outperformance is not appropriate, and constitutes a retroactive decision to claw back the benefits of outperformance to a greater extent than Ofgem agreed to in its RIIO-GD1 determination. It is bad regulatory practice, that dilutes incentives to reduce costs, and works against the customer interest. Nonetheless, we note in the context of RIIO-ED2 that the degree of sector outperformance by the DNOs has been less in RIIO-ED1 than by the GDNs during RIIO-GD1.

Hence in the context of the RIIO-GD2 review, the proposal to move to an 85th percentile target is unfounded. It would be doubly inappropriate at RIIO-ED2.

Moreover, if applied at RIIO-ED2, this target would run a very high risk of introducing data and model error into the determination of the efficiency frontier. The RIIO-ED1 models may provide a less reliable basis for forecasting future expenditure than they seemed at the time of setting the RIIO-ED1 price control, as they will be used to predict expenditure requirements in a time of significant uncertainty for the electricity industry due to the transition to Net Zero that is needed in RIIO-ED2. Furthermore, as we describe below in response to Ofgem's questions on the disaggregated modelling, the statistical reliability of the disaggregated modelling appears to have deteriorated relative the RIIO-ED1 analysis.

It would therefore be inappropriate for Ofgem to set a more demanding efficiency target than the 75th percentile at RIIO-ED2. It should retain consistency with the RIIO-ED1 approach, and previous price reviews. We also suggest Ofgem considers the effect of removing the Information Quality Incentive, which included a 75:25 weighting on Ofgem and company forecasts. In effect, this adjustment also reduced the effective efficiency threshold, so a move to the 85th percentile would represent an even greater departure from regulatory precedent.

COQ5. Do you agree with the proposed criteria for developing cost pools for a middle-up approach?

We agree with Ofgem's proposal to consider a wide range of cost assessment approaches, including middle-up modelling. As noted in response to COQ1, all cost assessment approaches have limitations, and we recommend drawing on a wide range of evidence to address these, and to recognise the limitations of particular techniques when combining them to calibrate the price control determination.

For certain categories of costs, middle-up models may resolve some of the limitations of top-down modelling (i.e. the difficulty in controlling for the relevant features of companies' operating environment which explain workload for a particular sub-category of cost) as well as some of the limitations of bottom-up modelling (i.e. conflating cost-allocation issues with inefficiency, and difficulty in identifying trade-offs between expenditure in different categories of cost).

We consider it appropriate, therefore, to consider the complementarity, cost trade-offs and complexity of boundaries between cost categories when potentially combining them within a single model, as Ofgem set out in 3.31 of Annex 2 to the SSMC.

With regards to Ofgem's fourth proposed criteria, it is important that Ofgem considers the risk of modelling bias and assuming an inaccurate relationship between costs and the chosen driver(s), across all models (and not just middle-up models). We consider that an extensive use of sensitivity analysis and a suite of statistical tests should be used to assess whether this criterion has been met by its proposed models.

COQ6. What cost drivers would be appropriate in a middle-up approach?

The choice of drivers will depend on precisely which categories of costs are combined into middle-up models.

We have tested combining ONIs and faults into a middle-up model. The model includes the total number of ONIs and faults as a driver. We used all available historical data (i.e. 2011-19 DPCR5 and RIIO-ED1 to date). Our

[19] Ofgem (30 July 2020), RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, para 3.24.

analysis shows that the model passes all diagnostic tests and the coefficient on the number of faults/ONIs is positive and significant.

We also tested combining CAI and business support into a middle-up model. As a starting point, we considered the drivers included in Ofgem's "core CAI" regression from RIIO-ED1 as a way to assess core CAI and business support. This model includes MEAV and asset additions as drivers. We found (like for our update of the CAI model) that the coefficient on the asset additions variable is not statistically significant. However, removing asset additions may not be a credible solution, as this leads to a model that does not control for DNOs' growth or workload. As this model fails to control for the volume of work DNOs are undertaking and for wider environmental factors (such as density) which may explain differences in DNOs core CAI costs, this model may not be a credible candidate for use at RIIO-ED2.

We also ran a version of the indrects model including Information Technology and Telecommunications (IT&T) and vehicle costs. However, the results show asset additions is still not significant. Hence, this model shows a similarly poor performance.

Our view is that Ofgem should consider a range of different model specifications, to explicitly address the possibility that modelled allowances can be sensitive to different model specifications. We advise Ofgem to consider a combination of scale-related drivers (e.g. MEAV, customer numbers, peak load, and network length), environmental factors (e.g. urbanity, sparsity regional labour), factors capturing the need for investment or other interventions to manage the network (e.g. asset condition, levels of network loading/utilisation), or in some cases workload metrics. However, off-model adjustments may be needed to ensure allowances are set at a level that reflects some of these factors, as it is unlikely to be possible to control for all of them using econometric models.

COQ7. What are your views on the CEPA developed totex and opex plus approach? What opex activities are there trade-offs that support the rationale for testing 'totex and opex plus' modelling?

We have reviewed CEPA's proposed approach to cost aggregation in its June 2019 report, prepared in the context of developing models for RIIO-GD2.

We agree with CEPA's view that, if Ofgem adopts a more granular approach to benchmarking, there is a risk that differences in cost allocation methodologies across DNOs could influence Ofgem's assessment of their relative efficiency. As we highlighted in COQ1, one of the advantages of using more aggregate models is that the risk of cost allocation choices affecting modelling outcomes would be reduced.

Indeed, at RIIO-GD2 Ofgem eventually seems to have dismissed the use of the more disaggregated bottom-up models in its Draft Determination because it has found that "some of the bottom-up models' fit wasn't satisfactory" and because it had concerns "over the statistical robustness of some of the models", and also chose not to rely on (or present) any analysis based on opex plus models.[20]

In its PR19 decision, Ofwat used an approach similar to 'opex-plus' benchmarking, by including capital maintenance in its benchmarking models, but excluding capital enhancement costs, i.e. costs associated with delivering new outputs etc. Ofwat referred to this as 'base expenditure' or 'botex' modelling. This approach may be an improvement on middle-up benchmarking at the opex level, since it addresses trade-offs between opex and capex, e.g. the trade-off between higher levels of inspections, maintenance and repairs, against higher levels of asset replacement and refurbishment.

COQ8. Do you believe it is appropriate to use bottom-up, activity-level, disaggregated modelling in RIIO-ED2?

As noted in response to COQ1 and COQ5, we agree with considering a wide range of cost assessment approaches, including totex, middle-up and disaggregated modelling. By drawing on a range of evidence, Ofgem can address the fact that all cost assessment approaches may have limitations.

However, we do have concerns that disaggregated modelling for some cost categories may not be robust. A number of disaggregated cost categories also show statistical problems, such as poor model fit and the failure of important diagnostic tests (e.g. Reset test). Below we set out these cost categories.

[20] Ofgem, RIIO-GD2: Step-by-Step Guide to Cost Assessment, p. 5.

- **Tree cutting:** Ofgem's RIIO-ED1 tree cutting model, using spans cut and spans inspected, shows statistical problems. We replaced RIIO-ED1 cost forecasts with actuals for four years of outturn data. We found that spans inspected is no longer statistically significant, and shows a counterintuitive negative result. In COQ29 we explain our suggestions for alternative tree cutting models for RIIO-ED2 further.
- **Faults:** Another example of the problems with disaggregated cost assessment is the faults modelling. In this cost category, there is enormous variation in the unit costs of faults costs reported in the RIGs. It is not plausible to attribute such variation to differences in efficiency across companies. At RIIO-ED1, Ofgem relied on unit cost analysis for most of the cost categories in faults. However, many disaggregated categories of expenditure vary enormously across DNOs, so the model probably exaggerates the degree of variation in companies' efficiency. We show further analysis on faults unit cost variation in COQ29.
- **Inspection and maintenance (I&M)**: Ofgem uses unit cost analysis for inspection and maintenance. This model also does not show a good statistical fit. Our analysis shows that the wide variance in unit costs across companies is probably too wide to credibly be ascribed to variation in efficiency. We show further analysis on I&M unit cost variation in response to COQ29.
- **Business Support Costs**: Similar to faults and I&M, unit cost models may not be reliable because of wide variation in unit costs across industry. We have applied regression analysis to try to improve on Ofgem's unit cost modelling for core Business Support Costs. The results show the constant term is statistically significant. This demonstrates a substantial component of Business Support Costs are fixed per licensee, and do not vary in proportion to MEAV as Ofgem assumed in its RIIO-ED1 unit cost modelling. Therefore, we conclude unit cost modelling is not appropriate for business support, as unit cost modelling is equivalent to a regression with no intercept.
- **CAI:** There are problems with the modelling of CAI performed at RIIO-ED1, that would make it inappropriate for use at RIIO-ED2. As explained further in response to COQ30, we have updated RIIO-ED1 costs with outturn data for RIIO-ED1 and DPCR5. Our results show the coefficient on asset additions is no longer significant when using only historical data, suggesting asset additions does not explain variation in DNOs' CAI and Ofgem's RIIO-ED1 CAI model may no longer be suitable for use at RIIO-ED2. We show further analysis on alternative models for CAI in response to COQ30.
- **Workload Drivers:** We also have concerns regarding some disaggregated models that use workload drivers, and therefore do not highlight the efficiency benefits achievable by conducting lower volumes of work. For instance, Ofgem's RIIO-ED1 tree cutting model relies on two workload drivers (spans cut and spans inspected) which are under DNOs' control. It therefore penalises innovations that reduce volume of activities, but not quantity/quality of "true" outputs that benefit customers. In response to COQ29 we show further suggestions on alternative models for tree cutting. Disaggregated modelling can also be distorted by cost trade-offs, even if Ofgem controls for them to some extent by applying the upper quartile adjustment to the results emerging from all disaggregated models.

Ofgem expressed similar concerns regarding disaggregated modelling in the RIIO-GD2 Draft Determination. Ofgem dismissed the use of disaggregated models in its Draft Determination because it has found that "some of the bottom-up models' fit wasn't satisfactory" and because it had concerns "over the statistical robustness of some of the models".[21] Our analysis concurs and we therefore consider that Ofgem should primarily rely on totex modelling to assess DNOs' overall efficiency, but disaggregated modelling may have some role to play.

If Ofgem decides to use disaggregated modelling for the RIIO-ED2 cost assessment, we would recommend it considers carefully whether its RIIO-ED1 cost groups and disaggregated drivers are appropriate, and likely to capture DNOs' expenditure requirements as they ramp-up investments to help achieve Net Zero through the electrification of heat and transport.

COQ9. If we use a combination of aggregated and disaggregated modelling approaches, how should we determine the weight we apply to each, in combining our analysis?

As noted above, we consider Ofgem should draw on a range of evidence, to address the limitations of comparative cost benchmarking. This will require Ofgem to develop rules for aggregating the results of alternative methods into a single set of ex-ante allowances. However, we do not necessarily think it will be appropriate simply to apply weightings to disaggregated, middle-up and totex methods.

[21] Ofgem, RIIO-GD2: Step-by-Step Guide to Cost Assessment, p. 5.

If Ofgem has reasons – once it has completed its analysis – to think some approaches are more accurate than others, placing any weight at all on less reliable methods risks building errors into the determination of RIIO-ED2 allowances, even if the effect of the error is somewhat diluted with weightings.

An alternative approach to weighting factors might be to define modelled costs for each company as the maximum of the modelled costs implied by the alternative methodologies under consideration, applying the upper quartile adjustment to the modelled costs (estimated using this rule) across all companies. This would prevent errors in one model that understate efficient costs for a particular company affecting its allowances, while protecting customers from exaggerated costs through the upper quartile adjustment. By taking the maximum of modelled costs before applying the catch-up efficiency target, this approach would not necessarily increase allowances across the industry as a whole; instead it would remove the extent to which biases present in a particular model or modelling method disadvantages any given DNO. We note this approach is used in Germany and there may be merit in exploring this concept further.

Rather than simply weighting together alternative methods, Ofgem could also use top-down regression modelling to define allowances for the majority of expenditure categories, but use disaggregated modelling in targeted areas. For instance, while totex modelling can be useful for identifying levels of efficient costs for DNOs' business as usual activities, they will not capture the acceleration of expenditures required to achieve Net Zero. Disaggregated models could be used to define the rate at which allowances need to expand as the penetration of LCTs causes rising demands for electricity on distribution systems.

COQ10. If we did not use disaggregated modelling approaches, what approach should we consider for disaggregating totex allowances for the setting of PCDs?

To set PCDs using disaggregated totex allowances, we believe that Ofgem could use a similar approach to that used in its RIIO-GD2 Draft Determination, also discussed in Annex 2 of the consultation document.[22] For RIIO-GD2, Ofgem distinguishes between regressed costs, non-regressed costs and technically assessed costs.

At RIIO-GD2, Ofgem employs two approaches for setting PCDs. Firstly, for those categories associated with technically assessed cost categories, Ofgem determines efficient costs that are then used to set the relevant PCDs.

Secondly, for regressed and non-regressed cost activities, Ofgem derives disaggregated allowances from the top-down totex allowance per GDN, based on company specific data. Specifically:

- Ofgem calculates a scaling factor (proposed totex divided by submitted totex), which determines the average reduction to submitted totex based on the totex modelling process;
- Then, Ofgem calculates a weighting factor for individual cost activities, according to the activity's share of adjusted costs, such that workload adjustments are captured in the disaggregated allowances; and
- Finally, Ofgem multiplies submitted costs for each activity by the scaling factor and relevant weighting factor to derive disaggregated allowances, which can then be used for the setting of PCDs.

We believe there are merits in this approach and we would suggest Ofgem considers it for use at RIIO-ED2 alongside consideration of potential bottom-up methods for determining PCD values, such as the costs and volumes for the specific activity benchmarked across all licensees.

[22] Ofgem (30 July 2020), RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, p. 45.

16. Model Specification

COQ11. What model estimation options should be considered for our cost assessment and why?

Whichever of the Pooled Ordinary Least Squares (POLS), Random Effects (RE) and Stochastic Frontier Analysis (SFA) approaches Ofgem uses, it is important to ensure Ofgem has a process in place for demonstrating the statistical validity of the methods it selects, and ensuring that the modelled costs and efficiency gaps it obtains are not unduly influenced by the choice of estimation technique. We consider POLS and RE are probably the most appropriate estimation techniques. The coefficients and efficiency gaps show very similar results, and both models pass all diagnostic tests apart from the White test.

While SFA has theoretical benefits, as it can disentangle data error, firm-specific effects and modelled inefficiency, in practice its ability to do so is likely to be limited by the small number of cross-sectional observations in the dataset. There are also a number of different SFA estimators, which vary according to how the firm-specific effects and inefficiency are specified in the model and the assumed statistical distributions of these components. These choices inject some subjectivity into the modelling and are likely to result in modelled efficiency scores being highly sensitive to subjective choices by Ofgem.

COQ12. Do you agree with our proposal to continue using Cobb-Douglas functional form? Why?

Logarithmic models (which imply a Cobb-Douglas functional form) better capture the relationships we would expect (i.e. based on intuition) between costs and drivers than linear models. Logarithmic models imply proportional relationships between costs and drivers, whereas linear models imply absolute relationships.[23]

We therefore consider it reasonable to use the relatively simple Cobb-Douglas functional form as the main basis for Ofgem's analysis, and not, for instance, use the more complex translog model specification used by Ofwat at PR14. The Cobb-Douglas functional form works well with small sample sizes and, unlike the translog model, allows for the inclusion of more independent cost drivers.

However, we do not consider that Ofgem should preclude considering other functional forms. Ofgem systematically runs the Reset test to assess the validity of its models. If a model fails this test, it might indicate that the assumptions of constant returns to scale made in Cobb-Douglas functions does not hold.

As Ofgem explains, the Reset test assesses "whether there are any omitted non-linearities in the model. If this test fails, it might be appropriate to test a different model specification (e.g. inclusion of a quadratic term in case of univariate regression or a translog specification)".[24] Ofgem's academic advisor at RIIO-GD2/T2, Professor Andrew Smith, also suggests that, if a model fails the Reset test, Ofgem should consider an alternative functional forms.[25]

Ofgem could also consider applying statistical tests to help it choose between linear and logarithmic models, i.e. the Box-Cox test.

COQ13. Do you have any views on our proposed model selection criteria?

We generally agree with the model selection criteria Ofgem has proposed. We believe that model selection should be based broadly on the following steps, that we summarise below:

- **Step 1:** In selecting a model, Ofgem should pick drivers that are relevant for the cost category considered, based on economic and technical intuition about the major factors causing differences in costs across DNOs. Ofgem should exclude explanatory variables that are under management control. By excluding endogenous variables, the model provides a more accurate assessment of companies' relative efficiency and avoids the potential incentive for companies to manipulate drivers to increase allowances.
- **Step 2:** Ofgem should run different regressions with a combination of the selected cost drivers from Step 1, checking that the sign of the coefficients aligns with its expectations and that the magnitude is plausible, discarding drivers that do not satisfy these two criteria.

[23] For instance, in a linear model specification, the coefficient on a driver defines the increase in costs in £ resulting from a unit change of 1 in the driver, independent of the size of the company. By contrast, a logarithmic model specification assumes proportional relationships, i.e. the coefficient represents the percentage change in costs resulting from a 1 per cent increase in a driver.
[24] Ofgem (9 July 2020), RIIO-GD2: Step-by-Step Guide to Cost Assessment, p. 15.
[25] Prof Andrew Smith (June 2019), Note for Ofgem on the computation of CSV weights, p. 9.

- **Step 3:** As Ofgem also explains in Appendix 5 of Annex 2 to the consultation document, it should check the statistical significance of the estimated coefficients. However, given the small sample size, we do not believe Ofgem should immediately discard variables that are not statistically significant. In addition, Ofgem should investigate whether the estimated relationship is robust, i.e. the estimated coefficients behave in a similar way across different model specifications.
- **Step 4:** Finally, Ofgem should consider the statistical validity of the model as a whole. To do so, it should consider the tests used at RIIO-ED1 and discussed also in Appendix 5 of Annex 2. These are the Reset test, Normality test, Pooling test for panel effects and White test for heteroskedasticity, though the latter is less important when Ofgem runs the model with robust standard errors. The Ramsey Reset test for model specification is particularly important.
- **Step 5:** Beyond these tests, Ofgem should also consider whether individual companies are outliers, and consider the stability of its modelled costs for individual companies to changes in model specification. While the statistical tests listed in Step 4 can indicate whether modelled coefficients are reliable, the key output Ofgem takes from comparative benchmarking models is a projection of modelled costs for each company in its sample. If a company is an outlier, this would suggest that the model may not be reliable, especially as a basis for predicting the outlier company's costs. Also, because the sample size is small (14 cross-sectional observations), Ofgem will only be able to consider a small number of drivers in its models. Hence, assessing the stability of individual companies' modelled costs to changes in model specification will also be important to demonstrating the reliability of Ofgem's cost forecasts for RIIO-ED2. Furthermore, in cases where modelled efficiency gaps are sensitive to modelling choices, we suggest that Ofgem makes a very cautious assessment of the evidence, and of how robustly it can conclude that companies' expenditure projections include elements of inefficiency.

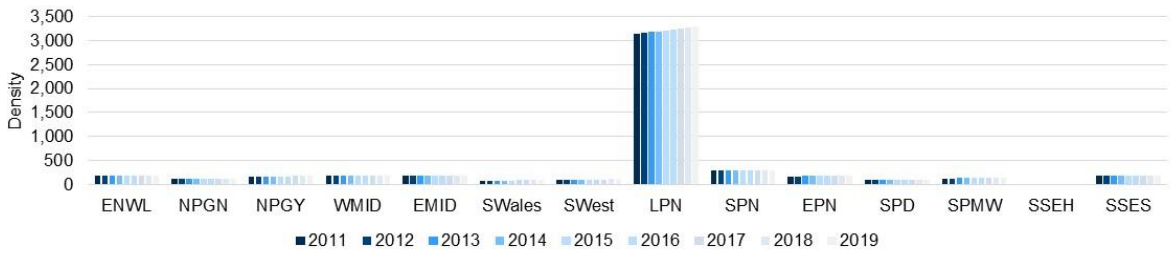
17. Regional and Company Specific Factors

COQ14. Do you agree with the proposed criteria for assessing regional and company specific cost factors that we have outlined?

As Ofgem sets out in paragraph 5.6 of Annex 2 of the consultation, we agree it is reasonable for Ofgem to consider the materiality, uniqueness and controllability of any company-specific factors before making allowances for them. We also agree that Ofgem should consider whether factors are controlled for in econometric models or addressed adequately through other adjustments.

As at previous price reviews, we expect that regional wages, density and sparsity will be important determinants of DNOs' costs that meet the criteria of materiality, uniqueness and non-controllability. For instance, as Figure 4 shows, LPN's density is considerably higher relative to other DNOs, as it serves London. Hence, these factors will need to be controlled for in the cost assessment.

Figure 4: DNOs Historical Density (2011-19)



There is strong evidence to support the very high costs associated with running a utility business in central London due to the more challenging working environment than elsewhere in the country.[26] In addition, there is also strong evidence that wages are materially higher in London and the South East than elsewhere. To ensure Ofgem sets price controls that remunerate the efficient costs of DNOs operating in the South East – and avoid over compensating those operating in other parts of the country – it is important that Ofgem controls for these factors in its RIIO-ED2 cost assessment.

COQ15. What are your views on our approaches to account for regional and company specific cost factors in our modelling?

We agree that regional factors can be controlled for using explanatory variables in regression equations, or using pre-modelling adjustments. We support Ofgem continuing the approach used at RIIO-ED1 to control for regional wages, density and sparsity.

We have attempted to control for regional factors using explanatory variables in totex regression equations, by identifying a list of cost drivers for RIIO-ED2 models which control for environmental factors, as summarised in Table 8.

[26] See, for instance: NERA Economic Consulting and Arcadis (31 October 2019), Understanding the Baseline Level of Efficiency in London: Prepared for UK Power Networks, Thames Water, Scotia Gas Networks and Cadent Gas.

Table 8: List of Cost Driver Candidates Controlling for Environmental Factors for ED2 Models

Candidate Drivers	Relevance for RIIO-ED2 models	Under DNO Control
Density	• This is defined as the number of customers over area (in square kilometres) of each DNO and reflects how the number of customers in a DNO's distribution service area relative to the size of the area impacts on network planning, design and wider Core CAI costs.	No
	• The density cost driver links to the pre-modelling adjustments applied by Ofgem to capture the company-specific request of LPN (London-factors) and SSEH, which are both related to environmental factors out of DNOs' management control.	
	• It follows that when including density we run the model without the pre-modelling adjustments, to avoid double counting.	
Gini Index	• The Gini index captures the variability of customer density within an area and must be combined with density to provide useful results.	No
	• As with density, when including Gini Index we run the model without the pre-modelling adjustments, to avoid double counting.	
Area	• It measures the area served by each DNO in square kilometres.	No
	• It is a time-invariant variable but unlike density/Gini index it is less relevant to Core CAI as if fails to provide an indication of the amount of asset /customers served within the area and therefore the costs associated with network planning and design.	

As noted in COQ2, we have run a number of alternative totex models. Our preferred model combines density and scale measures, removing the need for some regional factors. This model replaces a CSV dominated by MEAV with customer numbers and network length, which are less controllable and less likely to be distorted by differences in the unit costs of above-ground and underground assets. It also captures regional topography using density and "Gini".

We add the Gini Index alongside our controls for density, to capture the costs of running a dispersed network. By controlling for density and Gini, this totex model does not need separate adjustments for regional factors for density/sparsity.

Since the RIIO-ED1 price control, we (together with Thames Water, Cadent Gas and SGN), commissioned NERA and Arcadis to conduct further work to evaluate the impacts on LPN's costs from the particularly complex and challenging operating environment in central London. In its report 'Understanding the Baseline Level of Efficiency in London', it has identified the key factors affecting the cost of performing utility services in London, as compared to other parts of the country, and quantified the effect of these differences.[27] For each of the potential London factors, NERA conducted an assessment drawing on data from the Consortium to assess whether each factor was unique to London and whether it was within management control. It then quantified each factor's effect on utilities' costs.

[27] NERA Economic Consulting and Arcadis (31 October 2019), Understanding the Baseline Level of Efficiency in London: Prepared for UK Power Networks, Thames Water, Scotia Gas Networks and Cadent Gas.

18. Real Price Effects and Ongoing Efficiency

COQ16. Do you agree with our proposed approach to index RPEs, rather than setting an ex-ante allowance based on forecasts?

In RIIO-1, network companies' allowances were indexed RPI, and were provided with ex-ante allowances for expected inflation in input prices above Retail Prices Index (RPI) through RPE allowances. At RIIO-2 Ofgem now intends to index network companies' allowances to CPIH, which typically increases more slowly than RPI: from 2011 to 2019 (the years of RIIO-ED1 with outturn data), average RPI inflation was 3.1 per cent per annum, and average CPIH inflation was 2.1 per cent[28]. If these trends continue, then network companies can expect an additional 1.0 per cent ongoing efficiency challenge relative to RIIO-1 on cost areas not covered by RPE indexation, simply as a result of the formula change. It is therefore more important than previously that other mechanisms within the price control adequately control for the input price pressures faced by energy network businesses.

Ofgem plans to index aspects of allowances to other price indices instead of providing an ex ante RPE allowance. As set out in paragraph 6.7 of Annex 2 of the consultation, Ofgem proposes for RIIO-GD2/T2 to "'true up' RPE adjustments annually based on out-turn differences between CPIH and input price indices".[29]

Ofgem's intention in introducing RPE indexation was to protect consumers from forecasting risk. Ofgem notes it "want[s] to ensure that incentives on outputs and costs only reward companies for genuine performance improvements"[30], While it is difficult to see what impact RPE indexation has on companies' incentives, indexation can (at least in theory) reduce forecasting risk for consumers. However, it also reduces the stability of revenues received by companies and bills paid by customers.

While indexation can (in theory) reduce risk for customers and companies, if the selected indices do not accurately reflect companies' external cost pressures, then the indexation approach introduces additional revenue risk into the revenue-setting process. For instance, if the combined Labour or Materials RPE indices are an imperfect proxy for the actual cost pressures faced by companies, then a negative shock to the RPE index may reduce allowances without a corresponding reduction in costs.

This additional risk has knock-on implications for companies and customers. The potential for non-cost reflective changes in allowances may increase financing costs and lead to insufficient investment in the network, to the detriment of current and future customers. Companies can hedge general inflation risk (e.g. using financial instruments like inflation swaps and including indexation in contractor contracts), but this may not be possible for these more obscure indices Ofgem is now proposing to use. This risk is particularly acute in the content of the economic disruption being caused currently by the COVID-19 pandemic and the possible effects of Brexit in early 2021 which will undoubtedly take time to unwind. For instance, some labour cost indices have been volatile, reflecting the reduction in earnings by furloughed workers, which would not reflect the cost pressures faced by energy networks, whose staffing requirements have not changed materially (and may even have risen in some cases) since the start of the pandemic.

Additionally, productivity improvements and input price increases are partially correlated. Therefore, indexing RPEs makes the combined frontier shift less cost reflective than setting two ex-ante allowances.

We therefore advise that Ofgem exercises considerable care when developing RPE indexation mechanisms for RIIO-ED2, taking account of the volatility of candidate indices, and demonstrating the relevance of the selected indices to DNOs' costs. Demonstrating their relevance should not just involve a qualitative assessment of whether the indices capture similar categories of inputs to those required by the DNOs. Rather, Ofgem should demonstrate that indices track DNOs' costs reasonably accurately from year-to-year.

Given the difficulties in predicting RPEs to set an ex-ante allowance, and the challenges of calibrating a suitable index that does not introduce new risks, there may be a case for setting an ex-ante frontier shift allowance that nets off the expected effects of RPEs and ongoing productivity improvement. Subject to assessing economic conditions at the time of the RIIO-ED2 determination, we expect that the average, expected RPE over the RIIO-ED2 period

[28] Based on Office for National Statistics (ONS) inflation data.
[29] Ofgem (30 July 2020), RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, p. 42.
[30] Ofgem (30 July 2020), RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, p. 43.

may well be within the range of evidence on long-term productivity improvement that Total Factor Productivity evidence from other sectors suggests that DNOs can achieve.

There is therefore a strong case for assuming these two elements of the price control net to zero, and indexing the price control to Consumer Prices Index including Housing (CPI-H) without applying any further frontier shift adjustments.

This would also have the benefit of significantly simplifying the cost assessment process for both Ofgem and companies. This approach would represent a more demanding target than under the RIIO-ED1 framework, because (as noted above), CPI-H tends to rise at around 1 per cent per annum less quickly than RPI. It would also avoid the possibility of double-counting the productivity improvements already embedded in some PPI indices (i.e. for manufactured outputs) that Ofgem might consider using as part of its RPE index. Finally, by applying its totex model to forecast RIIO-ED2 costs, Ofgem's comparative modelling already accounts for catch-up productivity improvements and the benefits DNOs are realising through R&D, technological improvement and enhanced working practices.

As noted in our response to OVQ34 we believe there may be merit in adding in a "self-correcting" mechanism to address any long term impacts on performance due to COVID-19. If our suggestion to net off ongoing efficiency and RPEs were adopted, then a separate index would be needed for tracking COVID-19 effects.

COQ17. Do you agree with our proposal to have a high materiality threshold for RPEs? What are your views on the materiality level for RPE submissions, and the criteria we use to select input price indices?

For RIIO-ED1, DNOs submitted RPE proposals as part of their Business Plans. Ofgem assessed these proposals on the basis of the following criteria:

- Exposure to risk
- Impact on incentives
- Volatility and predictability of network charges
- Balance of charges between current and future consumers
- Complexity and unintended consequences
- Resource costs

As explained in response to COQ16, Ofgem proposes to set an RPE allowance for electricity distribution companies that tracks movements in a set of external indices. Ofgem proposed the same approach for gas distribution and transmission. As set out in paragraph 6.9 of annex 2, to assess the materiality of RPE submission for gas and transmission, it followed the approach proposed by CEPA. CEPA adopts a two-step approach to building up each of the RPE indices: first, it selects the cost categories which are material enough to include an RPE index for a particular company; second; it selects external data series which will feed into the RPE index.

The input cost categories CEPA examines are General Labour; Specialist Labour; Materials; Plant & Equipment; and Transport. For RIIO-GD2/T2, CEPA assesses whether the input cost category represents at least 10 per cent of totex. If so, the category is deemed material and is included in an RPE index. If the input cost category represents less than 5 per cent of totex, CEPA deems the category immaterial and does not include it in an RPE index. The allowance will instead be indexed to CPIH inflation.

For cost categories which represent between 5 and 10 per cent of totex, CEPA carries out an additional materiality test. If the RPE for the cost category is forecast to contribute to more than 0.5 per cent of totex during RIIO-2, then the category is deemed to be material. This approach allows a category which is small but whose costs increase substantially faster than inflation to still be considered material. Once a cost category is deemed to be material, CEPA then selects which data series will be used to measure the RPE.

The process suggested by CEPA to assess materiality is subjective, and there is a risk that if most input prices tend to rise more quickly than inflation, ignoring small cost categories on the basis of materiality would systematically understate the likely rate of growth in DNOs' costs over time.

A simpler and more object approach to setting RIIO-ED2 allowances would to index all costs to CPI-H, as suggested in response to COQ16.

COQ18. Do you agree with the suggested common input and expenditure categories for structuring RPEs in ED2?

The input cost categories Ofgem examines are General Labour; Specialist Labour; Materials; Plant & Equipment; and Transport. As noted in response to COQ16, Because Ofgem proposes to index RPEs rather than setting an ex-ante allowance, these indices should reflect the movements in efficient costs that a company will face during RIIO-ED2.

If an index responds more or less to external events than companies' actual cost pressures, then the company will be arbitrarily rewarded or penalised, even with an ex-post adjustment based on outturn RPE index levels. Hence, the new indexation approach means that the choice of individual indices is more important than under Ofgem's previous practice of setting ex-ante RPEs.

Ofgem should make sure the mixture of indices is justified with reference to the actual costs the DNOs are incurring. If year-to-year movements in RPEs do not accurately reflect companies' external cost pressures, it introduces additional revenue risk to companies. The selected indices need to be reflective of the activities the DNOs are undertaking, including the increasing requirement for specialised labour DNOs are facing as they take on new responsibilities. Assessing the extent to which these indices track the DNOs' real labour cost pressures will be necessary to assess the risk that the new indexation approach over or under compensates DNOs' for changes in the market cost of labour during the RIIO-ED2 control period.

While Ofgem has introduced the concept of RPE indexation as a way to insulate customers from the risk of forecasting error, its approach introduces new risks for DNOs, especially where the indices themselves do not perfectly track external pressures in input costs.

The selected indices may have been adequate for setting ex ante RPE allowances in previous decisions, because they were only intended to capture the long-term tendency for some input costs to rise faster or slower than general inflation. Using them for indexation, however, has wider consequences (e.g. financeability) and so requires a higher standard of evidence.

COQ19. Do you agree with our proposed approach, and its scope, to set an ongoing efficiency assumption for RIIO-ED2?

We agree on Ofgem's proposal to use growth accounting data. However, we have concerns regarding the RIIO-T2/GD2 approach of taking an arbitrarily high-end number as an overall ongoing efficiency challenge. As set out in paragraph 6.21 of Annex 2 of the consultation, Ofgem's GD2/T2 DD proposes to: [31]

> "apply an overall ongoing efficiency challenge of 1.2% per year for capex and repex, and 1.4% for opex for all network companies (apart from electricity distribution). We chose the upper bound of our initial reference ranges for ongoing efficiency[32], to set companies a stretching ongoing efficiency challenge that helps deliver value for money for consumers."

CEPA's report concludes by presenting a range of possible ongoing efficiency targets (0.5-1.2 per cent for capex, 0.5-1.4 per cent for opex), along with some caveats and points of consideration. From this range, Ofgem has ignored all of the caveats and selects only the upper bound of each range.

When presented with a range of methodological choices where the precise answer is not obvious, the most reasonable approach would be to "triangulate" between the options, e.g. through selecting a midpoint or a weighted average of multiple estimates.

Instead, Ofgem has placed full weight on the upper bound of CEPA's estimate, and hence its determination relies on a series of unjustifiable positions that all serve to exaggerate the scope for ongoing productivity improvement. This is an aspiration that companies should become more efficient more quickly, and not an allowance grounded in evidence.

We also have concerns regarding the justification of giving customers a return on innovation expenditure. In paragraph 6.24 of Annex 2 of the consultation, Ofgem notes the following: [33]

[31] Ofgem (30 July 2020), RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, p. 45.
[32] 0.5% - 1.2% for capex and repex, 0.7% - 1.4% for opex.
[33] Ofgem (30 July 2020), RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, p. 46.

> "we proposed to incorporate a 0.2% ongoing efficiency challenge to account for previous innovation funding awarded in RIIO-1. Indeed, we believe that consumers have effectively provided the network companies with additional upfront allowances through innovation funding, and that this should have driven efficiency. CEPA derived the additional ongoing efficiency challenge to account for these expected improvements by treating innovation funding like an investment previously made by consumers. Efficiency improvements in RIIO-2 can then be seen as the 'return on investment' of innovation funding."

Rather than basing the uplift on a bottom-up estimate of the relationship between innovation and productivity gains, CEPA seeks to estimate "cost savings to consumers [that] would be required in order to make providing the innovation allowances seem a reasonable investment"[34]. CEPA estimates that, if transmission companies reduced costs at a rate of 0.2 per cent per annum during RIIO-2, this would represent a fair return to customers on the upfront costs of the innovation schemes.

CEPA's approach to determining the innovation funding adjustment has no basis in the additional cost reductions an efficient company could reasonably achieve during RIIO-2. Instead, the target takes what CEPA deems to be a fair return to customers (4.2 per cent), and "goal seeks" an arbitrary set of input assumptions that yield that result, including the cost reduction profile during RIIO-2.

Any adjustment which accounts for the cost savings from innovation funding must also consider the extent to which those benefits are already captured in business plans and/or the pre-adjusted cost allowances. This potential double count was at issue in Northern Powergrid (NPg)'s successful appeal of RIIO-ED1 to the Competition and Markets Authority (CMA) in relation to "smart grid" savings. CEPA acknowledges the importance of controlling for embedded cost savings in light of the CMA appeal, but makes little effort to actually do so.

COQ20. Do you agree with our proposal to use a growth accounting approach as our primary source of evidence to set an ongoing efficiency assumption? What parameters would best support this approach?

We agree on Ofgem's approach to use growth accounting data as a primary source of evidence for assessing the long-term potential for DNOs to improve productivity and working practices, though as noted above it may be sufficient to index the price control to CPI-H without applying an additional productivity improvement target.

To assess the scope for productivity improvement, Ofgem should rely on Gross Output measures of productivity

To the extent that Ofgem does rely on long-term growth accounting data, we suggest the use of gross output-based (GO) Total Factor Productivity (TFP) as the most appropriate measure of productivity improvement, using data from competitive sectors of the economy. Data from within the utilities sector is not suitable for use in target setting because it conflates catch-up and productivity improvement.

Past regulatory decisions have consistently concluded that GO measures are more appropriate than value added (VA) to measuring potential for efficiency improvement for regulated companies:

- At RIIO-T1/GD1, Ofgem concluded that "the VA measure of productivity only allows us to evaluate the impact of the use of labour and capital on outputs, and thus limiting the costs that this can be applied to. Therefore, to fully evaluate the productivity improvements that a network company can make would require making additional assumptions about the use of intermediate inputs"[35]. Ultimately, Ofgem did use a VA measure in addition to a GO measure, though its reasoning for doing so is not clear[36].
- At RP5, the Competition Commission (CC) concluded that "GO is a closer approximation of a company's cost base. This is because it contains labour, capital and intermediate inputs (as a company's cost base does) rather than just labour and capital". The CC still used a VA measure in addition to a GO measure because it is less susceptible to measurement error and changes in the vertical structure of industries[37].
- At PR19, Europe Economics concluded that "the value added TFP measure represents frontier shift only when the production function is such that capital and labour are separable from intermediate inputs and technical progress favours capital and labour only, which might be considered a rather implausible

[34] CEPA (27 May 2020), RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper, p.24.
[35] Ofgem (27 July 2012) RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix, para 3.15, p.19.
[36] Ofgem stated that two GDNs, NGN and SGN, argue that GO measures are susceptible to measurement error and changes in vertical structure of industries. Ofgem never explicitly stated whether it agreed with the GDNs' argument, but instead simply stated that it uses evidence from "both GO and VA measures of productivity". Source: Ofgem (27 July 2012), RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix, paras. 3.16 & 3.22.
[37] Competition Commission (8 November 2013), Northern Ireland Electricity Limited price determination, Appendix 11, para. 6.

assumption"[38]. Ofwat largely agreed with Europe Economics' conclusion, finding that "the gross output measure is generally preferable [though] it is not superior in all cases"[39].

In support of Ofgem's RIIO-GD2/T2" Draft Determination, and with no explanation for why it does so, CEPA presents its VA values as its "reference value" and GO as its "downside" sensitivity, which contradicts regulatory precedent. In fact, regulatory precedent shows that GO-based measures are more appropriate, and therefore should be used at RIIO-ED2.

Ofgem should consider recent evidence on low productivity growth

When using long-term growth accounting data, we also advise that Ofgem considers carefully the time horizon over which it examines trend data on anticipated productivity improvement. In general, because of short-term volatility in productivity indices, long-term average growth rates can provide useful information on the expected rates of productivity improvement in the future. However, this is not the case when there is evidence of structural changes in the economy.

For instance, in the productivity analysis that informs Ofgem's RIIO-GD2 Draft Determination, CEPA acknowledges that productivity growth since the 2008 financial crisis has been below its long-term trends, even as the economy has recovered[40]. CEPA's approach effectively assumes that productivity will return to long-term levels during RIIO-2, but no reliable evidence suggests that it will. Recent Bank of England forecasts have also materially reduced the in the wake of the COVID-19 pandemic, and it no longer corroborates CEPA's assumption[41]. Therefore, we recommend Ofgem gives weight to productivity estimates in the post-crisis period, reflecting the evidence that productivity growth rates will not immediately return to pre-crisis levels.

Ofgem should make a balanced assessment of the available evidence

It is also important that Ofgem (or its advisors, as appropriate) consider a balanced assessment of the evidence, when interpreting long-term productivity indices. CEPA's report informing the RIIO-GD2/T2 Draft Determination presents Ofgem with a range of possible numbers and some points of consideration for Ofgem in selecting a final number. The final range of potential numbers is as follows:

- Low: 0.5 per cent for opex and capex. This is the 1997-2016 average Total Factor Productivity (TFP) and Labour Productivity (LP) growth for CEPA's "wide" industry definition, measured using a GO approximation;
- High: 1.4 per cent for opex and 1.2 per cent for capex. This is the 1997-2016 average TFP for the average of the "narrow" and "wide" industry definition, measured using VA data, and includes the full 0.2 per cent innovation funding adjustment[42].

Leaving aside Ofgem's use of this range, CEPA's range overstates the long-term trends in productivity improvement implied by the evidence presented in its report. As explained above, the GO-based productivity data should not be a lower bound; it would be more appropriate to treat this evidence as the reference value.

Also, CEPA's "reference value" is based on the midpoint between its "narrow" and "wide" industry definitions, using productivity indices measured in VA terms. However, CEPA ignores the "narrow" industry definition when calculating the lower bound, focusing instead on the "wide" industry definition estimated using the GO-based measures of productivity. If CEPA's selected comparator industries are relevant to energy network companies' productivity in VA terms, then they are equally relevant when measured in GO terms.

Ofgem then sets its target based on the top end of the range[43]. While CEPA's range already exaggerates the scope for productivity improvement, this approach of taking the top end of the range compounds the problem. We recommend that Ofgem takes a more balanced reading of the evidence at RIIO-ED2.

[38] Europe Economics (January 2018), Real Price Effects and Frontier Shift, p. 74. Emphasis added.
[39] Ofwat (July 2019), PR19 Draft Determination, Security cost efficiency technical appendix, p. 121.
[40] CEPA (27 May 2020), RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper, p.16.
[41] Bank of England (August 2020), Monetary Policy Report, Table 1C.
[42] Narrow vs. wide industry definition: whether the regulator estimates productivity for industries closely related to the regulated industry ("narrow") or for most or all of the macroeconomy ("wide").
[43] Ofgem (9 July 2020), RIIO-2 Draft Determinations – Core Document, para. 5.36.

There is no case for an additional productivity premium to reflect the benefits of past innovation funding

While we support the use of growth accounting approach as Ofgem's primary source of evidence to analyse the scope for ongoing efficiency, we do not support the RIIO-T2/GD2 proposal to apply an additional efficiency challenge to provide "a reasonable return to consumers on the upfront funding they provided in the form of innovation allowances in RIIO-1" through the Network Innovation Competition (NIC) and the Network Innovation Allowance (NIA)[44].

This adjustment to the RIIO-GD2/T2 Draft Determinations is not justified by any evidence on the efficiency improvements that companies can reasonably expect to achieve during RIIO-2. Ofgem/CEPA assume a fair rate of return to customers (4.2 per cent), and back-solve the level of cost reduction necessary to pay back this funding. This approach is flawed for a number of reasons:

- Cost reductions are only one objective of the NIC and NIA funding. The funding has also targeted environmental objectives including renewables integration and improved ancillary service provision;
- Ofgem has not considered what portion of the innovation funding savings have been captured in business plan forecasts, or already achieved historically; and
- Macroeconomic evidence on productivity improvement already accounts for the effect of R&D expenditures in other parts of the economy. Ofgem should consider the extent to which the R&D funding provided to network companies exceeds that undertaken in competitive sectors of the economy.

[44] CEPA (27 May 2020), RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper, p.35.

19. Disaggregated Cost Assessment

COQ21. Do you agree with our proposed approach on forecasting options for RIIO-ED2?

Ofgem is exploring several different models for planning strategic Net Zero investments by DNOs for RIIO-ED2. The transition to Net Zero means that DNOs are expected to face larger demands in the future. As Ofgem rightly acknowledges, while there are various intermediate targets for Net Zero, there is still uncertainty around the pathways that DNOs may follow to achieve these targets, thus impacting how Ofgem sets the allowances for LRE.

- We agree that a common scenario approach is needed for RIIO-ED2
- Differing regional rates of change should be addressed through uncertainty mechanisms
- If different DNOs have different "best view" scenarios, comparative analysis will need to be used with care

We agree that a central forecasting approach is needed for RIIO-ED2

Whilst there are a number of different pathways to achieve Net Zero, we believe a central Net Zero compliant forecasting approach could, and should be used to set the initial RIIO-ED2 ex-ante allowances. We acknowledge that local stakeholders may have different targets for Net Zero, and some local environments may be more conducive to low carbon technologies than others. For instance, we would expect to see more uptake of EVs in urban areas than more rural ones, because of range limitations and (in London) congestion charging linked to vehicle emissions. However, our current view is that, with appropriately defined and calibrated, broadly mechanistic uncertainty mechanisms, such variation could be addressed via uncertainty mechanisms and not by Ofgem attempting to conduct cost assessment across fourteen fundamentally different business plans. A key element of any central forecast will be confirming up front the allocation methodologies that should be applied so that the sum of the fourteen business plans equates to the GB total. An Ofgem led workstream in this area would be beneficial to ensure all parties are clear in advance of submission.

If different DNOs have different "best view" scenarios, comparative analysis will need to be used with care

Ofgem has also proposed that it will, as at RIIO-ED1, ask DNOs to submit expenditure forecasts for a number of alternative scenarios, potentially based on common ENA scenarios. DNOs would also identify which of the scenarios represents their "best view". We consider Ofgem's proposal to request from DNOs a number of alternative scenarios to be sensible, given the ranges of uncertainty around how the future energy system will evolve.

Ofgem will need to recognise that the "best view" of how the energy system will evolve may not be the same for all companies and/or regions, and consider how it applies comparative benchmarking in a way that addresses this. If different companies' "best views" are based on different baseline decarbonisation scenarios, it is likely to be harder for Ofgem to compare their "best view" totex projections using purely top-down models, without penalising the company in the region with the most ambitious decarbonisation plans. Such variations may need to be addressed outside of the totex modelling.

COQ22. What are your views on our proposal for establishing network impacts and assessing LRE requirements for RIIO-ED2?

For RIIO-ED2, we agree with Ofgem's proposal to improve the transparency and amount of information available on the utilisation of the network. By increasing transparency, DNOs can better harness the potential for flexibility providers to offer up solutions to meeting load growth. We also agree with Ofgem's proposal to increase the use of monitoring equipment at lower voltages.

DNOs need this information to better identify the impact that increases in peak demand will have on their networks, which itself depends on the utilisation of existing assets. It would be harmful to customers for DNOs with lower levels of utilisation to receive the same payment for accommodating load growth as DNOs with higher levels of utilisation, which will incur greater reinforcement costs or payments to flexibility providers. Please see our response to OVQ9 where we set out our thinking on how a utilisation strategy incentive could provide a fundamental pillar of the RIIO-ED2 arrangements with respect to LRE requirements.

COQ23. Do you agree with our proposal to compare flexibility solutions and network based solutions evenly in our cost assessment?

Yes, we agree with Ofgem's proposal to treat payments under flexibility contracts and the costs of network-based solutions evenly in the cost assessment. A key benefit of current arrangements is that it does not prescribe solutions and instead focusses on outputs such as £/MW. This enables DNOs to innovate and take actions that provide the greatest value for money using all available information. Importantly, both market based flexibility and network based solutions offer "optionality" that can help cost efficiently manage uncertainty and there is not a one size fits all approach.

It follows that Ofgem should continue to focus on benchmarking via common unit costs and make use of existing data as much as possible. For example, whilst previously reinforcement unit costs have been based on network solutions, now they are starting to factor in flexibility procurement, which provides equivalent output i.e. releasing network capacity. This is leading to a blended unit cost that can be benchmarked in a consistent manner.

Further discussion on the approach to assessing option value via a CBA would be helpful, as there are a range of tools which could be used and it is crucial that DNOs use a consistent CBA methodology when assessing investment options. As part of this, we are keen to develop a methodology that recognises the nature of flex procurement in terms of deferring expenditure. This will require consideration of how allowances and flex contracts transfer from one price control to the next.

COQ24. How should we treat the fixed costs of procuring flexibility when considering flexibility solutions as an alternative to reinforcement?

DNOs that have tended to use more flexibility would tend to have lower (not higher) Asset Additions, and DNOs' ambition on developing flexibility services is likely to be poorly captured by MEAV.

Similarly for business support costs, at RIIO-ED1 Ofgem modelled these costs using MEAV as a driver in a unit cost model. However, the fixed costs of flexibility services increase operational costs, so would not be captured in MEAV, therefore any knock-on effects for business support costs from providing flexibility services would not be remunerated either. The RIIO-ED1 totex modelling would suffer from the same limitations. Neither the bottom-up nor "macro" CSVs would capture any differences in companies' usage of flexibility services or the option value of the capabilities the DNOs have built, so these costs would appear to be inefficient.

While the RIIO-ED1 cost assessment modelling would not remunerate these fixed costs, we believe there are ways in which Ofgem's cost assessment methods could be improved to recognise these better. For example, DNOs could reflect minimum requirements for DSO capabilities in the business plan and be benchmarked on this at totex level. Separately, where a DNO believes there is justification in exceeding these minimum requirements these could be assessed separately via a CBA approach. This could involve analysing the costs that would be borne by taking a reinforcement only approach with respect to energy scenarios, versus investing in DSO capabilities that can offset these costs as well as wider whole system costs as discussed in our response to OVQ22.

COQ25. What are you views on the use of LIs as outputs in RIIO-ED2?

We are broadly supportive of retaining LIs for the primary network as outputs in RIIO-ED2.

We agree with the proposal to review band definitions given the sensitivities observed in RIIO-ED1. We also welcome the opportunity to develop and potentially incorporate additional elements such as fault levels, flexibility and DG. We support further development on the calculation of firm capacity, noting work elsewhere in the electricity sector with respect to Tertiary Windings and the potential ramifications for firm capacity on electricity distribution networks.

Our proposals for measuring network utilisation for the secondary networks, as set out in our response to OVQ9, offers an alternative means for creating an appropriate output metric for the secondary network rather than attempting to replicate the primary LI methodology to the secondary network.

COQ26. What are your views on the treatment of incremental costs in RIIO-ED2?

We acknowledge and agree with Ofgem's concern, that its cost assessment risks mistaking efficient behaviours, such as oversizing investments to avoid future reinforcement costs or installing more expensive equipment to minimise losses, as inefficiency. This problem arises in cases where Ofgem sets allowances using cost modelling

that controls for factors such as the volume of work undertaken or the size of the company (e.g. as measured by MEAV), but takes no account of the value of outputs delivered.

Ofgem's consultation document sets out three options:

1) Report core costs against the primary investment driver and report the additional incremental costs in a memo table or secondary table together with any benefit volumes as reportable;
2) Report total costs against the primary investment driver, with a supporting memo table(s) setting out the incremental costs; or
3) Report total costs only, ignoring the requirements incremental cost reporting.

We support option 1, in which DNOs would report both the incremental costs and benefits delivered for reasons unrelated to the primary investment driver. However, Ofgem will need to issue careful guidance to DNOs on how such benefits should be computed by DNOs, and how DNOs should isolate which costs and benefits are incremental, as compared to a scenario in which DNOs incur the minimum levels of expenditure required to deliver the primary investment driver.

The only downside of this approach Ofgem cites is administrative complexity of preparing the data. However, if DNOs are incurring incremental costs to deliver customer benefits, we consider it reasonable that Ofgem requests that companies quantify and report such benefits. This reporting of both incremental costs and benefits is important for companies, to ensure such incremental costs are properly remunerated, and for customers, to ensure that companies are delivering value for money when DNOs incur incremental costs.

We consider that Option 3 (ignoring the effect of incremental costs) would prevent Ofgem from adequately controlling for this impact on DNOs' efficient costs. We recommend that Ofgem does not pursue this option. DNOs will not necessarily be "doing similar activities" unless Ofgem develops common planning standards that govern when DNOs should incur incremental costs. In fact, DNOs' regional stakeholders may have different requirements that DNOs invest to accommodate, and the decarbonisation pathway may differ across regions, necessitating different quantities of incremental costs. Accordingly, there will be a tendency for allowances to be set based on benchmarks set by DNOs pursuing the lowest cost strategy (involving fewest incremental costs and benefits).

Options 1 and 2 would both report the incremental costs associated with works that deliver secondary benefits, in addition to the costs reported alongside the primary investment driver. These approaches to reporting would allow Ofgem to isolate the costs associated with the primary drivers, and set allowances that reflect the costs DNOs incur to meet such core objectives. For instance, Ofgem could remove incremental costs from totex regressions, and evaluate them using separate analytical approaches, so the modelled allowances predicted by the model represent a "baseline" level of expenditure required on the assumption that DNOs incur only the costs required to meet their required minimum levels of service.

However, under Option 2 Ofgem would still face a challenge of assessing the reasonableness of the incremental costs companies report, as it would have no "line-by-line" attribution of incremental costs to benefits.

It could address this problem to some extent using data on the total outputs delivered to customers. For instance, Ofgem could conduct totex modelling using models that control for overall (i.e. company-wide) changes in outputs delivered for customers. This could be done by including performance or output measures as explanatory variables in a regression equation, or netting off the value to society of incremental benefits generated from totex before running regressions. However, this may be challenging in practice, especially because some incremental benefits may not be associated with benefit values that are readily quantifiable (e.g. oversizing assets to reduce the costs of accommodating future demand growth or speed up future LCT connections). Also, this approach would not allow Ofgem to control for incremental costs in any disaggregated modelling, as benefits could not be attributed to particular line items of expenditure.

The practicalities of separating out incremental costs needs careful consideration, given the ramifications this may have for both any re-statement of historical expenditure and how costs in business plan are represented. As a potentially significant change to reporting arrangements we would support ongoing dialogue with Ofgem and a possible "dry-run" of selected areas ahead of formal submissions in 2021, to ensure all DNOs have interpreted any revised guidance in a common manner.

COQ27. Do you agree with our proposal to maintain the RIIO-ED1 approach to assessing Non-op capex costs in RIIO-ED2?

To assess capital expenditure on new and replacement non-operational assets, Ofgem proposes to maintain its RIIO-ED1 approach in RIIO-ED2. Thus, for IT&T (non-operational), non-operational properties, non-operational vehicles and small tools, equipment, plant and machinery, Ofgem would calculate allowances based on unit cost benchmarking using both historical and forecast costs, relying on MEAV as a driver.

As also summarised in Appendix 3 of Annex 2 to the SSMC, Ofgem set DNOs' RIIO-ED1 allowances based on the following approach:[45]

- Non-operational properties: unit cost benchmarking based on industry median using 13 years of data (2011-2023) and MEAV as cost driver.
- IT&T (non-operational): 75% weight on expert qualitative assessment of costs and 25% weight on unit cost benchmark to group-level median, using 13 years of data and MEAV as driver. The quantitative assessment was combined with operational IT&T.
- Non-operational vehicles: the assessment of non-op capex vehicles was combined with the assessment of CAI vehicles and transport. The unit cost analysis assessed as non-operational property.
- Small tools, equipment, plant and machinery: Ofgem conducted a qualitative review of each DNOs costs, arguing cost data was not reported consistently.

We believe that Ofgem's approach at RIIO-ED1 was too simplistic. Indeed, it is not plausible that these cost categories can be explained individually by MEAV. There are potential trade-offs between these categories and others, e.g. depending on how much of certain activities DNOs choose to outsource, and DNOs may make different cost allocation choices rom each other.

For example, there could be potential cost allocation choices between IT&T (non-operational) and operational IT&T, or between non-operational vehicles and CAI vehicles and transport. Thus, we believe that, at RIIO-ED2, Ofgem should rely mainly on totex modelling as these models internalise trade-offs and are relatively immune to cost categorisation issues, as we discussed in response to COQ1.

COQ28. Do you agree with our proposal to maintain the RIIO-ED1 approach to assessing NLRE in RIIO-ED2?

We believe modifications are required to areas of Non-Load Related Expenditure (NLRE) assessment for RIIO-ED2 compared to the assessment approach used for RIIO-ED1.

Ofgem's approach to assessing NLRE at RIIO-ED1 employed a combination of unit cost comparisons, supplemented by technical/engineering analysis. Given the trade-offs companies face between cost categories, with increasingly "blurred lines" between some categories of expenditure, we do not consider it is appropriate to maintain the current approach to assessing NLREs at RIIO-ED2. We have updated elements of the NLRE modelling from RIIO-ED1 and (as described below) our update highlights some of the problems with the modelling.

Diversions

At RIIO-ED1 Ofgem relied on unit cost benchmarking to determine efficient unit costs, where the industry median calculated on eight years of RIIO-ED1 forecast data was applied to submitted forecast volumes. As Ofgem proposes to maintain this approach at RIIO-ED2, we have updated the unit cost benchmarking using only outturn costs and volumes for the period 2016-19.

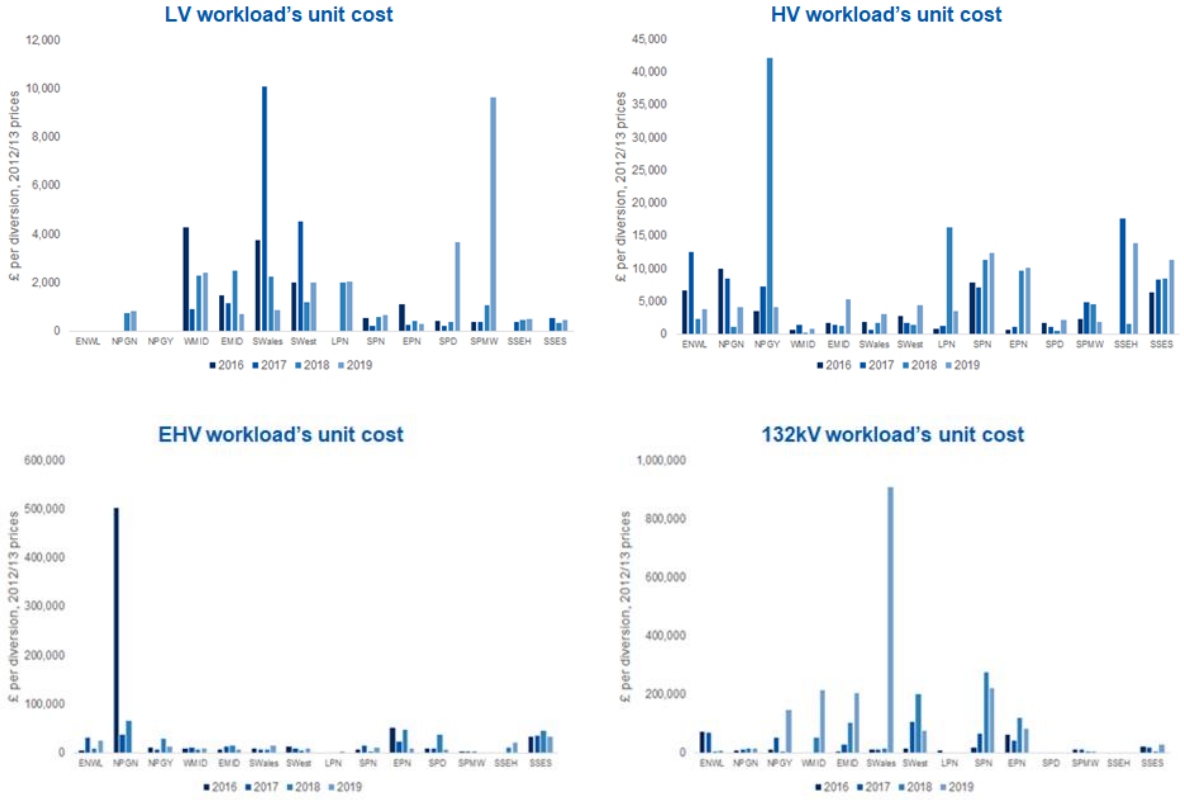
Our analysis reveals that there is large variation in the unit costs of diversion costs reported by the DNOs. Figure 5 shows expenditure per diversion across companies by voltage level (LV, HV, EHV and 132kV). Unit costs are materially different across DNOs, suggesting that Ofgem's approach at RIIO-ED1 of relying on unit cost benchmarking for this cost category may not be appropriate. The range of variation in unit costs is wider than Ofgem can credibly ascribe to efficiency differences across companies.

As a remedy to this problem, Ofgem could rely more heavily on its totex modelling, though if it is not technically reasonable to assume these models explain adequately the need for DNOs to incur diversion costs, this area of expenditure could potentially be taken outside the model. However, given the wide variance in unit costs across

[45] Ofgem (30 July 2020), RIIO-ED2 Sector Methodology Consultation: Annex 2 Keeping bills low for consumers, p. 156-157.

companies, Ofgem would probably need to apply technical assessment of both unit costs and volumes to make a reasonable assessment of DNOs' expenditure requirements in this area.

Figure 5: Expenditure per diversion across companies: unit cost on conversion of wayleaves to easements, easements, injurious affection & related costs



Asset Replacement

On asset replacement, Ofgem proposes to maintain its approach used at RIIO-ED1 for RIIO-ED2. At RIIO-ED1, Ofgem applied unit cost adjustments to submitted asset replacement costs. The target unit cost was set on an asset-by-asset basis. In order to determine the unit cost for each asset, Ofgem relied on one of the following:

- industry median based on four years of actual data (2011-14);
- industry median based on forecasts for RIIO-ED1 (2016-23);
- industry median based on 13 years of data (2011-23); and
- qualitative view of unit cost.

In order to determine the efficient view of volumes, Ofgem used:

- an age-based model using two age profiles with the results of both factored into Ofgem's volume assessment. This ensured the modelling was based on both historical and forecast data;
- run rate analysis where assets volume is assessed as a proportion of the total asset base; and
- expert assessment.

We consider there are some limitations on modelling asset replacement costs using unit cost benchmarking at a granular level. There are also trade-offs between asset replacement and other cost categories that mean the volumes of work required cannot be assessed based solely on the age of the assets. Rather, the need for reinforcement and in the relevant part of the network and the criticality of the network assets in question affects the economic need for replacement. For instance, DNOs may choose to replace relatively old assets where load is likely to grow, or replace relatively high unit cost assets where doing so can improve outcomes for customers. The use of EJPs and CBAs as part of the assessment process also needs to be fully thought through, with clarity given as to the likely weight to be applied to modelling versus these other forms of assessment.

We therefore recommend that Ofgem's cost assessment should focus on totex modelling, while controlling for differences in the DNOs' asset health and the need for reinforcement created by the loading and utilisation of network assets.

COQ29. Do you agree with our proposal to maintain the RIIO-ED1 approach to assessing NOCs in RIIO-ED2?

We consider that there are problems with the modelling of NOCs performed at RIIO-ED1, and as such we do not suggest that Ofgem retains its approach without implementing improvements to it. If such improvements are not possible, as noted above in response to (COQ1 and COQ2), it may be more appropriate to place greater weight on totex modelling.

While it may be possible to improve on the RIIO-ED1 NOCs models, several of the NOCs categories exhibit wide variation in costs we have not been able to explain using unit cost or econometric models. These categories include tree cutting, faults and I&M.

Given these issues, we suggest that Ofgem should focus on using totex modelling to set DNOs' allowances for "business as usual" activities, but use disaggregated modelling in a more targeted way to address the limitations of the very high-level totex modelling. For instance, disaggregated modelling could be used to assess the costs of targeted programmes of work to expand the system to achieve Net Zero, that are not adequately controlled for using the totex modelling which controls for scale. Average unit costs or the "slope" coefficients in benchmarking regressions could be used to calibrate uncertainty mechanisms. Disaggregated modelling (in particular expert engineering review) may also be needed to assess the need for DNOs to undertake major replacement programmes or to assess the efficiency of developing new DSO capabilities or services to support achievement of Net Zero.

COQ30. Do you agree with our proposal to maintain the RIIO-ED1 approach for assessing CAIs in RIIO-ED2?

We consider that there are problems with the modelling of CAI performed at RIIO-ED1, that would make the same approach inappropriate for use at RIIO-ED2.

It is not reasonable to assume the largest share of ("regressed") CAI is only explained by MEAV and asset additions (i.e. scale and the size of the capex programme). DNOs are facing significantly more challenging network planning workloads due to the power systems transition towards Net Zero. DNOs can address capacity limits in networks using capex or non-network solutions such as flexibility, making asset additions potentially insufficient as a control for the scale of DNOs' programmes of work (see our response to COQ24).

We have updated Ofgem's CAI model and re-estimated the regression using 2011-2019 historical data, this shows asset additions are no longer statistically significant when using only historical data, suggesting asset additions does not explain variation in DNOs' CAI. However, removing asset additions (without replacing it with an alternative driver) would not constitute a credible alternative model, as it would fail to control for the volume of work DNOs are undertaking.

We have attempted to improve Ofgem's RIIO-ED1 model, first by identifying a long-list of potential cost drivers for CAI which control for scale, workload and environmental factors, as summarised in Table 9.

Table 9: List of cost driver candidates for ED2 Core CAI model

Candidate Drivers	Relevance for Core CAI Costs	Under DNO Control
MEAV	• It reflects the scale and the composition of the network, but differences in MEAV may not reflect differences in the scale of CAI activity, e.g. underground unit costs are several times higher, but may not be driving up CAI costs.	Yes (in the long-term)
	• MEAV only captures CAI associated with capital activities, i.e. adding assets, not operational activities like using flexibility contracts with DES providers.	

Candidate Drivers	Relevance for Core CAI Costs	Under DNO Control
	• Does not capture many environmental factors (e.g. London effects) causing the same asset to be more complicated to operate in different conditions.	
	• Data revisions during RIIO-ED2 suggest the asset register is not entirely accurate.	
MEAV UG and MEAV OH	• These two variables de-compose MEAV into Underground MEAV assets and all other assets ("MEAV OH") to better capture the potential impact of UG assets on CAI.	Yes (in the long-term)
	• These drivers suffer from the same limitation cited for MEAV.	
Network Length/ Customer numbers/ Peak demand	• All three variables are alternative scale variable to MEAV, and may be avoiding some of the possible distortions associated with MEAV (e.g. OH vs UG).	To some extent
	• Unlike MEAV however they fail to capture the complexity and composition of DNOs' assets (e.g. complexity associated with rural vs. urban networks).	
Asset Additions	• Asset additions captures changes in the scale of DNOs' network and is therefore a measure of DNOs' workload.	Yes (in the long-term)
	• The assumption is that growth in DNOs' capex program (through larger number of asset additions) is associated with larger Core CAI expenditure.	
	• Whilst a measure of workload, it fails to capture growth in non-asset solutions, such as flexibility contracts, which may still driver Core CAI.	
Average asset additions	• Captures the change in average asset additions over DPCR5 and RIIO-ED1 (actuals only) and address the limitation of asset additions which may be lumpy when assess on a year-to-year basis. Similar pros/cons to asset additions.	Yes (in the long-term)
YoY% Network Length / Customers / Peak demand	• All three variables are alternative workload variable to asset additions, and may address some problems of collinearity between MEAV and asset addition.	To some extent
Faults	• The number of faults may provide an indication of the complexity and network planning requirements of DNOs and is a driver of costs for call centres and control centres.	To some extent
Number of connections	• Proxy for the possible impact of workload on Core CAI, although this measure is currently imperfect as it does not reflect the total number of requests received by DNOs.	To some extent
FTE	• Number of hours worked by an employee divided by the hours of a full-time member of staff in an equivalent role according to the contract of employment. Reflects the average productivity of workers for each DNO.	Yes
Density	• Is defined as the number of customers over area (in square kilometres) of each DNO and reflects how the number of customers in a DNO's distribution service area relative to the size of the area impacts on network planning, design and wider Core CAI costs.	No
	• The density cost driver links to the pre-modelling adjustments applied by Ofgem to capture the company-specific request of LPN (London-factors) and SSEH, which are both related to environmental factors out of DNOs' management control.	
	• It follows that when including density we run the model without the pre-modelling adjustments, to avoid double counting.	
Gini Index	• The Gini index captures the variability of customer density within an area and must be combined with density to provide useful results.	No

Candidate Drivers	Relevance for Core CAI Costs	Under DNO Control
	• As with density, when including Gini Index we run the model without the pre-modelling adjustments, to avoid double counting.	
Area	• It measures the area served by each DNO in square kilometres.	No
	• It is a time-invariant variable but unlike density/Gini index it is less relevant to Core CAI as if fails to provide an indication of the amount of asset /customers served within the area and therefore the costs associated with network planning and design.	

Using these variables, we have identified a number of possible alternative CAI models, as Table 10 shows:

- **Model 1** splits MEAV into underground assets and other assets, as MEAV places greater weight on underground network assets. Also, since asset additions is variable over time, we tested average measures of asset additions to control for DNOs' workload, by taking the average per control period (i.e. average of DPCR5 and average of RIIO-ED1, only for outturn data). The results show a small, insignificant coefficient on MEAV (exc. UG assets), and the coefficient on smoothed asset additions remains insignificant. Given the coefficient on additions is insignificant, this model may not be a credible model for RIIO-ED2.
- **Model 2** introduces density, defined as customers per square kilometre of network area. A positive coefficient suggests that as density increases, CAI costs increase. We ran a new model specification with MEAV, density and additions averaged over DPCR5 and RIIO-ED1. As expected, this model shows that LPN's ranking improves, as the model captures the high costs of serving dense urban areas, while SSEH's (i.e. in the most rural area) score worsens. In this model (as for all other models including density), we removed company specific adjustments for LPN and SSEH to avoid double counting when density is included. However, a downside of this model is that it does not control for DNOs' workload (i.e. as asset additions is removed without an alternative driver added in its place).
- **Model 3** adds the Gini Index alongside density, to capture the costs of running a dispersed network. The coefficient on the Gini Index is not significant, and also average additions become insignificant too. Therefore, this alternative approach also appears not to be credible.
- **Model 4** uses a combination of customer numbers and length instead of MEAV, as well as density and asset additions. However, we removed average asset conditions as we do not find a statistically significant result for this driver in any of the combinations with length, customer numbers and density. As Table 10 shows, the coefficient on numbers of customers is negative, which is counterintuitive. Therefore, this is not a credible model for RIIO-ED2.
- **Model 5** includes the number of faults (including ONIs), but the coefficient is insignificant.
- **Model 6** includes the number of connections as a workload variable to substitute for asset additions. We also add density to control for differences in operating environments across DNOs. However, the coefficient on the number of connections is not significant.

Table 10: Alternative CAI models, using 2011-19 actuals

Drivers	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6
Log of MEAV		0.46***	0.40*		0.59***	0.70***
Log of MEAV (exc. UG)	0.07					
Log of UG MEAV	0.54***					
Log of Avg Additions	0.18	0.35*	0.26			
Log of Density		0.12***	0.23*	0.32***	0.08***	0.08***
Log of Gini index			0.50			
Log of Total length				1.52***		
Log of Customers				-0.62***		
Log of nr. Of Faults					0.12	
Log of nr. Of Connections						0.01
Constant	-2.87	-5.95***	-4.75	-5.47***	-7.40***	-7.94***
Adjusted R^2	0.58	0.67	0.68	0.76	0.64	0.63
Normality	0.34	0.05	0.07	0.02	0.26	0.09
Reset	0.19	0.85	0.64	0.15	0.80	0.48
White	0.01	0.32	0.28	0.27	0.76	0.64
Chow	1.00	1.00	1.00	0.58	0.73	0.85
*10% significance level, **5% significance level ***1% significance level						

Therefore, we conclude, despite the problems with Ofgem's model, it is not straightforward to identify a reasonable alternative. We have experimented with many different combinations of drivers, and all show some statistical problems, or counterintuitive or statistically insignificant relationships. We tried to address some of these issues using a middle up model. For instance, as mentioned above in COQ6, business support could be aggregated with CAI. However, this model shows similar results, as asset additions is still not a significant driver.

One possible explanation for this problem is that DNOs make different cost allocation choices and trade-offs between NOCs and CAI, capex and CAI, and business support costs and CAI. Such choices would undermine the reliability of the inferences Ofgem can draw from CAI disaggregated models. Hence, given the challenges associated with modelling CAI in isolation, it may be more appropriate to conduct benchmarking to assess the efficiency of DNOs' expenditure at a totex level.

It may be appropriate to assess some categories of CAI using disaggregated modelling, e.g. IT&T would need to be assessed using expert evaluation because of the lumpy and company-specific nature of this cost item. In such cases, it may be appropriate to remove such cost items entirely from the totex models.

CAI costs will also tend to increase over time, due to the DNOs taking on new responsibilities, such as DSO capabilities (see our response to COQ24). It will not be possible for Ofgem to observe historical relationships between DNOs' CAI and variables that capture these new requirements. If Ofgem runs regressions using DNOs' forecast CAI data and all DNOs forecast costs that include the development of similar, new capabilities, these costs could be allowed for through the modelling, e.g. through an uplift in the constant term in the regression, but at present we are not aware of any cost drivers available to Ofgem that could capture these new requirements.

COQ31. What are your views on the different approaches presented for the treatment of BSCs in RIIO-ED2?

As for CAI, we consider that there are problems with the modelling of business support costs performed at RIIO-ED1, that would make it inappropriate for use at RIIO-ED2.

We apply regression analysis to try to improve on Ofgem's unit cost modelling for core business support costs. We conclude unit cost modelling is not appropriate for business support, as unit cost modelling is equivalent to a regression with no intercept. The results also show this model does not pass the Reset test.

We have attempted to improve Ofgem's RIIO-ED1 model, first by identifying a long-list of cost drivers for BSCs which control for scale, as summarised in Table 11.

Table 11: List of Cost Driver Candidates for RIIO-ED2 Business Support Costs Model

Candidate Drivers	Relevance for Business Support Costs	Under DNO Control
MEAV	• It reflects the scale and the composition of the network, but differences in composition of the network (e.g. overhead vs. underground) not directly relevant to business support costs.	Yes (in the long-term)
	• Does not directly capture environmental factors (e.g. London effects) causing differences in business support costs.	
	• Data revisions during RIIO-ED2 suggest the asset register is not entirely accurate.	
Network Length	• Alternative scale variables to MEAV, which may avoiding some of distortions associated with MEAV (e.g. OH vs. UG).	To some extent
Customer numbers	• Fail to capture complexity of network, but this may not be as relevant for business support costs as for CAI.	
Peak demand	• Closely correlated with customer numbers, but less intuitive relationship with business support costs.	To some extent
Revenue	• Drivers tested at fast track decision in Ofgem's first set of disaggregated business support costs models, some used for specific subcategories (e.g. expenditure as driver of procurement costs, employees as driver of HR & non-op training).	Yes
Expenditure	• Strong rationale to suggest they drive business support costs, but since they are under company control, may fail to capture efficient spend.	
Employees		
IT end users		
Number of companies in group	• Depending on the model form, may capture extent of fixed costs at the group level.	To some extent

Using these variables, we have identified a number of possible alternative business support costs models:

- Model 1 tests the implications of including number of companies into the business support costs model together with MEAV, as this may capture the extent of fixed costs at the group level. The results show the coefficient for number of companies is negative, although not significant. A negative relationship implies the presence of fix costs at the group level, as the costs decrease with the number of companies per group. However, since the coefficient is not significant, this effect appears not to be statistically significant. Also, this model does not pass the Reset test. Therefore, this is not a credible model for RIIO-ED2.
- In model 2, we find similar problems if we include IT&T costs in the regression. As this model also does not pass the Reset test, we conclude it is not a credible model for RIIO-ED2.
- As an alternative to MEAV, we test the model using network length as an alternative measure of scale, which may avoid some distortions associated with MEAV (e.g. OH vs UG). We report the linear model, since the Box Cox test suggests this model performs better (in terms of 'goodness of fit') than the log-log equivalent. The results of model 3 show the coefficient on total length is statistically significant, and the model produces a similar range of efficiency scores to the specification with MEAV. However, the R-squared remains very low, leading to wide variation in modelled efficiency scores. Also, controlling for network length as a business support cost scale driver may not capture the scale of business activities that influence business support costs.
- In model 4, we use number of customers as a scale driver as an alternative measure of scale, which produces an improved model fit. As in model 3, excluding MEAV may avoid some distortions associated with MEAV (e.g. OH vs UG). The results show the coefficient on number of customers is positive and

statistically significant. The model passes Reset test, and has a larger R-squared than any other business support costs model we tested. However, an R-squared of 0.56 still leads to wide variation in efficiency scores, and suggest model may not be robust enough for relying-on for setting allowances.

Therefore, we conclude, despite the problems with Ofgem's model, it is not straightforward to identify a better one. Given the challenges associated with modelling business support costs in isolation, it may be more appropriate to conduct benchmarking to assess the efficiency of DNOs' expenditure at a totex level, except for cost items which are not comparable across companies (e.g. IT&T).

20. Cost Benefit Analysis

COQ32. Do you agree with our proposed application of CBA in the appraisal of investment options for RIIO-ED2?

We broadly agree with the proposed application of CBAs for appraising investment options.

There are a number of new areas to consider incorporating functionality into the Ofgem CBA template, for example;

- Comparing options against multiple scenarios, and;
- How to consider option value of deferred or delayed investment.

In our view, the CBA is a critical step in forming well-justified plans that are both ambitious and cost efficient. Through the CBA template Ofgem can consistently assess DNOs' investment plans and DNOs can likewise ensure that they supply all relevant information in a standardised format. Therefore, we would like to work with Ofgem to co-develop changes to the current CBA template to ensure that it is fit for purpose. For example, we have identified assumptions that need to updated to reflect the latest available information, as well as where additional input parameters should be added to ensure that the full range of benefits are visible. Given the imminent need for DNOs to run their plans through CBAs we believe updating the template is an urgent task and we will be happy to support the Ofgem team to get this finalised.

We note Ofgem's reference to sensitivity analysis around the Net Zero pathway (for certain investments). We would welcome clarification on whether these are adequately covered with the 2020 FES and subsequent DFES scenarios, or whether Ofgem is thinking of its own Net Zero pathway or pathways.

We would also highlight the need to align EJPs with CBAs. Our view is that the EJP should provide the options and specific engineering inputs, which are then applied in the CBA. Additional information on this through process in the business plan guidance is therefore welcome.

21. Engineering Justification Papers

COQ33. Do agree with our proposals to retain the requirement for DNOs to produce Engineering Justification Papers?

We endorse the approach proposed by Ofgem for the production of EJPs to support (not repeat) justifications such as NARMS and associated CBAs.

We are currently working on EJPs for projects and streams of work over the value of £1million, which would result in circa 300 EJPs being produced in addition to a similar number of CBAs. We therefore ask that Ofgem does not lower the threshold below this amount. This is the level that we believe would be required to meet Ofgem's requirements as part of presenting a robust business plan. We would like to share some sample EJPs with the Ofgem's engineering team in advance of the SSMD to gain their feedback in order that we can meet all of their expectations.

We believe there is value in a coordinated EJP and CBA working group to ensure consistency of templates and guidance between the two documents in order to avoid duplication and disproportionate number of documents being submitted to Ofgem in December 2021, particularly if only a limited amount of such extensive material from all fourteen licensees is actually evaluated by Ofgem.

COQ34. Do agree with our proposal retain the assessment framework for EJPS developed as part of the RIIO2 process?

We endorse the current framework for assessing EJPs and have no further comments to raise at this stage.

COQ35. Do agree with our proposal to adopt the principles outlined above to guide the production of EJPS and focus the engineering submission?

See our response to COQ33.

22. Data Assurance and Compliance

COQ36. What specific activities and methods should be adopted to ensure the Data, Data Assurance and Compliance processes of the RIIO-ED2 price control are run as effectively as possible?

We recognise that data assurance and compliance is essential for Ofgem to fulfil its role in assessing price control forecasts and protecting the interests of customers. We note our responsibility to ensure the integrity of the data that we submit and welcome the Data Assurance Guidance (DAG) provided by Ofgem to facilitate this.

We agree with Ofgem that the level of data assurance activity (be it external audit, internal audit, director sign off or management review) should be proportionate to the type of submission and, as such, be based on an informed risk assessment and common sense approach.

In determining the appropriate levels of checks and assurance, we will take into account both the likelihood of an error and the potential consequences of any such error given the ways in which we understand that data will be used. In many cases, our data is captured as part of long-standing processes and procedures that have been subject to regular checks and audits over the years. As such, we can have a reasonably high degree of confidence in its reliability. Where a new dataset is required, then it will be necessary for us to ensure that it is subject to more rigorous checks and assurance.

Clear and timely data guidance from Ofgem will facilitate us in providing accurate and consistent data. The greater risks to data quality will arise when a new dataset is required to tight timescales or there are last minute changes to data requirements. However, we will be cognisant of these risks and endeavour to mitigate them where possible through the use of internal checks and the use of third-party assurance as appropriate.

Expanding on this topic in more detail, DNOs will need clear and timely guidance and data templates which have been thoroughly reviewed and tested with licensees to facilitate as smooth a process as possible. We recommend that Ofgem build on existing reporting arrangements wherever feasible and sensible.

Lessons can also be learned to avoid the pitfalls seen in previous regulatory reviews, where the introduction of radically different arrangements at short notice created issues, for both licensees and the regulator. The RRPs were borne from Ofgem's experience as well as learnings from other regulators.

Where new activities and costs for RIIO-ED2 need to be captured in the Business Plan, we urge Ofgem to work on these areas as a priority, with history showing that new activities can result in different interpretations being taken at the outset if definitions and guidance are not clear. Ofgem may want to accelerate progress in new areas and hold specific sessions to ensure that all parties are clear, this needs to be well in advance of formal Business Plan submissions for the output to be able to be implemented by the DNOs. The recent work on DSO activities and costs highlights both the progress that has been made as well as the further work that is required in this space.

Furthermore, building appropriate error checks into reporting packs, as Ofgem has done with the annual RRP, facilitates the data assurance and compliance processes for both licensees and Ofgem. Having a clear and pre-planned Supplementary Questions process, akin to that employed by Ofgem for RRP and NIC should also be part of this suite of assurance measures. It would be helpful if Ofgem could consider an enhancement to this process, whereby licensees can receive clarity on whether their responses to Supplementary Questions (SQs) have successfully addressed the questions raised.

Finally, there is an opportunity for consideration of the materiality of issues from an efficiency perspective – this could be in the form of Ofgem employing a RAG rating to the materiality of the questions they pose to enable them to be triaged by Ofgem prior to issue and also by the DNO on receipt.

23. Uncertainty Mechanisms

COQ37. Do you agree with our proposed uncertainty mechanisms and their design?

Uncertainty Mechanisms (UMs) will play a materially greater role in the RIIO-ED2 price control than at RIIO-ED1. Given the potential level of uncertainty about the paths to Net Zero, this is inevitable. The package of UMs together with the base allowances, incentive arrangements and innovation funding must work effectively together to enable the required transformational change across electricity distribution. We therefore support in principle the concept of a common approach as outlined in the SSMC. We set out our thoughts on detailed aspects of the common framework in COQ40 below.

The definition of UMs will be critical to ensuring that there are no barriers to facilitating transformational change across electricity distribution, therefore they need to be well-defined and they must avoid being unnecessarily complex, burdensome and bureaucratic

Our preference is for mechanistic uncertainty mechanisms such as volume drivers as, if calibrated appropriately, these provide greater agility. There should also be clarity on why UMs are preferable to baseline funding and vice versa, to ensure consistency around the arrangements of their use during the period. Whilst we recognise that there will be a set of UMs, as much as possible Ofgem and DNOs should, where feasible, consolidate these to lessen the administrative burden whilst ensuring DNOs can respond quickly

Further work is needed to develop a common understanding of the overall package

Further work will be needed to ensure that there is a good and common understanding of how the mechanisms will work together as a package and to flesh out the details. We are keen to contribute to collaborative work on these matters and urge Ofgem to engage the industry on it so that there is more clarity by the time the ED2 sector specific methodology decision is published. It is essential that such work takes into consideration the overarching matters in the paragraphs below.

There should be no unnecessary complexity. Burdensome and bureaucratic processes should be avoided. This is important so that companies, possibly resulting in a risk of delay to desirable and needed investment, do not see the package of UMs as unworkable.

Given the potentially larger number of uncertainty mechanisms and their greater materiality, we would favour uncertainty mechanisms are mechanistic as far as possible rather than relying on judgemental assessment. We therefore favour UMs based on volume drivers. We note that the idea of PCDs with mechanistic funding triggers is also being explored in the context of Net Zero and consider that there is potential for these to play a role in other areas.

Ofgem should provide assurance that its processes are efficient and adequately resourced so that unnecessary delay in executing them is avoided. Particular attention needs to be given to how different mechanisms and processes in the price control interact with one another and can be operationalised efficiently, in particular:

- Clarity should be given where UMs might be seen to overlap in scope such that more than one mechanism may be relevant. We particularly think that the role of the generic Net Zero re-opener should be considered very much as a last resort and our preference is for UMs to be specifically targeted;
- The interaction between UMs and innovation funding mechanisms, especially where UMs are seen as a route to providing funding for investment in energy system transition;
- The interaction between UMs and the processes by which Ofgem may evaluate whether proposals for material projects against its criteria early or late competition and the resulting requirements; and
- Expectations should be made clear about the nature of customer and stakeholder engagement to support the use of UMs and how Ofgem will factor this engagement into its decision, particularly if the Uncertainty Mechanism (UM) may involve a material change in the overall price control. For example, how will potential impact on customers' bills be taken into account?

More clarity is needed about the rationale for choices

The SSMC lists the proposed mechanisms and describes each one. However, it does not present a comprehensive analysis of the reasons for the choice of the form of the mechanism. We think that this gap in the SSMC needs to be filled via an analysis which clearly spells out the criteria and how each proposal has been. Below we suggest specific indicators, which would indicate the choice of one or other type of mechanism. We urge Ofgem to make clear its own analysis.

Table 12: The main types of Uncertainty Mechanism and their criteria

Mechanism	Criteria
Pass through	• Costs which are driven by external parties that are outside of companies' control. • The actions of a DNO should have little to no bearing on the scale of these costs. They are independently determined, and by nature are not suitable for benchmarking activities (for example, licence fees).
Volume Driver	• Uncertainty should be driven primarily by the volume of work to be undertaken, including both the number and timing of any interventions. • Volumes should be triggered externally to remove risks of delivering beyond the economically efficient level of work. For example, work triggered by customer demand. • There should be evidence to support credible unit costs for use in the mechanism, which must also be fair, accounting for any regional adjustments.
Re-opener	• Uncertainty isn't well suited to be measured in units of a standard volume (for example, the costs aren't related to a standardised or repeatable activity). • Costs should be material under Ofgem's criteria (proposed as 1% of annual average base revenues (post TIM) in the SSMC). • Costs should be sufficiently low confidence so as to make other mechanisms (such as a PCD) inappropriate.

In addition, the balance between baseline funding and UMs should be carefully considered and in each case the choice should be made clear. UMs are appropriate when there is genuine uncertainty, but should not be used as a response to poorly justified proposals for base funding, as appears to be the case for some of the recent Draft Determination decisions. We therefore urge Ofgem to be very clear as to what criteria it will apply in making such choices. This will help companies gather appropriate and useful evidence in business planning.

Bespoke and common UMs

In general, we consider it preferable for UMs to be common to all DNOs where this is possible. A large number of bespoke mechanisms could bring unwelcome complexity. We note that Ofgem rejected the majority of bespoke proposals brought forward by transmission companies and gas distribution networks, in some cases replacing them with common mechanisms. We think there could be a role for bespoke UMs in a few cases, but they would need to be clearly justified. We agree with the information that Ofgem suggests is needed to support such a proposal in the Business Plan Guidance. Our preference and intention would be to explore the potential for commonality with other DNOs and provide the evidence of this as part of business plan submissions.

Comments on specific UMs

We set out here specific comments about some of the UMs proposed in the SSMC. Where we have not commented, we are broadly in support of including the UM in the form set out subject to the general comments above. Note that we comment specifically about the Net Zero re-opener in our responses to OVQ3 to OVQ9.

Cyber security

It is inevitable that there will be a level of spend on cyber security and that the requirements for protection of critical cyber assets will continue to evolve. This suggests that there needs to be a level of base expenditure as well as an UM. We would expect there to continue to be limited choice for companies in relation to whether to meet the specific security requirements. We would therefore expect that, as for the recent Draft Determination there should be no materiality threshold.

Physical security

The need to physically secure sites is tightly controlled under the PSUP programme. Given the existence of such processes, there is a reasonable case for considering treating required investment as a pass through cost, reducing the burden of a re-opener because we have little to no bearing on the scale of the costs incurred. If it is decided that the UM should be in the form of a re-opener, it is inappropriate to apply a materiality threshold as companies have virtually no choice over the investment. There should be an appropriate base allowance if sites are identified in advance of business plan submission.

Co-ordinated adjustment mechanism

We broadly support the intent of the Co-ordinated Adjustment Mechanism (CAM) as a measure, which may help to facilitate flexibility in the price control and help to achieve Net Zero. We strongly support the idea that any potential barriers to or enablers of whole system thinking should be removed or limited as far as possible. However, it is an untried approach and as such, it is likely to need careful attention in implementation. The similar mechanism applying to transmission and gas distribution will offer the opportunities for learning. Furthermore, it is not a complete answer to encouraging whole system thinking and should be seen as part of a wider package.

COQ38. Are there any other uncertainty mechanisms that we should consider? If so, how should these be designed?

Ofgem should consider including an uncertainty mechanism to deal with the additional costs of diversions.

During ED1 costs of diversions have increased markedly. We have incurred c£18m per annum over RIIO-ED1 compared to c£12m per annum over DPCR5 and are facing significant additional unfunded costs during ED1. One underlying reason is the material increase in the number of requests for diversions on the part of land agents. The incidence of diversion requests is difficult to predict and there is little opportunity in practice to avoid the associated costs. We expect there to continue to be an uncertain and growing demand for diversions.

We note the proposal to retain the uncertainty mechanism for rail electrification projects and agree with the expansion of its scope to cover projects conducted by companies not connected with Network Rail. However, this will cover only a small proportion of diversion requests. Nonetheless we consider the rationale for this uncertainty mechanism, recognised by Ofgem, to ensure that DNOs are funded for efficiently incurred costs holds for all diversion requests.

While it would be possible use a re-opener approach, we are also exploring whether a volume-driver approach could be used, perhaps based on numbers of different categories of diversion projects (in terms of complexity, size or voltage level. The advantage of a volume driver approach would be its transparency and reduced regulatory burden. This would also retain a strong incentive for efficient delivery. We believe it will be possible to derive robust unit costs for a limited number of diversion categories and proposed to work together with Ofgam and other DNOs to develop the case for and design of the mechanism.

COQ39. Do you agree with our proposed removal of the above uncertainty mechanisms for RIIO-ED2?

We agree with the removal of the UMs that Ofgem has set out and which will not be continued in RIIO-ED2.

COQ40. Do you agree with our proposed common approach for re-openers being applied to RIIO-ED2?

We agree that it is sensible for there to be a common approach to re-openers and we broadly agree with the specific features of the approach as far as they are set out. However, we think there should be further clarity about:

- the overall process by which re-openers will be evaluated, assessed and decided;
- the approach to Authority-triggered re-openers;
- application of materiality thresholds in specific cases; and
- the scope of aggregation.

Process issues

We agree with the shortening of windows for application. This is in line with a more streamlined and less burdensome process. However, having a shorter window addresses only one aspect of the process. Ofgem should set out as many details of the whole process and its timing from submission to the conclusion of its assessment and implementation in the Annual Iteration Process so that stakeholders are clear about how the risks are of such uncertainties are being addressed. It would also be useful to set out more clearly an overall view which brings

together all of the windows and UM processes that have been proposed. As presented in the SSMC it is difficult for stakeholders to see the whole picture as things stand.

Approach to Authority-triggered re-openers

Generally, we support the greater flexibility that Ofgem has to enable it to respond more dynamically to changing needs. We agree that Ofgem should be able to trigger UMs subject to the same materiality thresholds. The fact that it can trigger re-openers at any time, rather than during specific windows adds some flexibility but the ability to trigger any time combined with a 28-day short consultation period (which could be seen as unreasonably short if there are particularly complex issues to consider) raises some risks. It may be a challenge for companies and, particularly, for other stakeholders to mobilise resources to deal with such proposals at short notice. The ability and preparedness of all stakeholders to respond comprehensively to such proposals is important.

This might be best achieved if Authority-triggered re-openers were linked to a standard timetable. For example, it would be sensible for Ofgem to consider for the timing of re-openers in the context of the annual submission of regulatory information by companies in July each year and the Annual Iteration Process which provides the route for Ofgem to adjust revenues. A standard timetable reflecting these milestones could be developed. This would help companies and all stakeholders plan the resources that will be needed to respond to Authority triggered re-openers. We would encourage Ofgem at least to commit to a “no-surprises” approach by being as open as possible about its future intentions and plans. We also urge that Ofgem differentiates the timescales proposed for consultation of decisions depending on the nature of the re-opener proposal: complex or high-profile Authority triggered proposals should be consulted on for longer.

Application of the materiality threshold

A materiality threshold on individual UMs is sensible to ensure a fair balance of risks between customers and companies while avoiding burdensome costs of numerous smaller UM proposals. It is important to consider the applicability of the threshold in each case: please see our response to COQ38 above as regards cyber and physical security.

Scope of aggregation

Ofgem has signalled that it will be possible to aggregate for UM purposes. It defines both a lower threshold for individual aggregated items and a higher threshold for the total of the aggregated items. We can see that this is designed to prevent excessive levels of aggregation of very small impacts which is sensible. However, we question whether aggregating small items which are not fundamentally connected is appropriate. We believe the purpose of an uncertainty mechanism is to deal with specific identifiable risks. Simply adding together unconnected risks would seem to be inconsistent with a regulatory approach in other areas such as cost assessment and incentives. Allowing the aggregation of unconnected cost items potentially blunts the incentive to find efficient solutions. We would therefore prefer if any aggregation was supported by some underlying rationale.

24. Increasing Competition

COQ41. Do you agree that our flexibility proposals are sufficient to incentivise DNOs' native competition?

Yes, we agree with Ofgem's flexibility proposals not to require companies to submit additional information relating to native competition. Alongside flexibility, the totex incentive mechanism already provides a strong incentive for companies to use native competition to achieve cost efficiency.

However, we note that in RIIO-GD2 and RIIO-T2, the scope of native competition covered competition processes used to reduce all aspects of totex. While we agree that flexibility is the primary area where DNOs can deliver totex savings through native competition, there are additional activities around procurement processes for IT and communications systems, business support, etc, which can also provide benefits.

It would be helpful to understand if Ofgem still want to see details of our work to increase competitive pressures in these non-load related areas and if DNOs can receive recognition for these under the business plan incentive.

COQ42. Do you believe there are similarities between DNOs running early competitions and the roles and activities that may be related to electricity DSO functions?

Yes, we agree that roles and activities required for early competition are closely aligned with the DSO role and functions around Planning and Network Development. Under this role, DNOs will continue their work in developing a detailed view of network needs, building on existing processes such as LTDS and flexibility tenders, to provide a five to ten-year outlook, as part of the proposed Network Development Statement. This will provide a transparent picture of distribution network needs, well ahead of time and crucially, well before any early stages of project development. Consequently, DNOs will be able to highlight where potential network needs meet the qualifying criteria for early competition and present this information to the market in a clear way, aligned to how we plan to highlight our flexibility needs to stakeholders.

Given this alignment of roles, we believe that it would be more efficient and more transparent to stakeholders for DNOs to take on the roles and activities required for early competition, as part of the DSO functions. Given the DSO role around planning and development, DNOs will be best placed to explain where developments on the network have led to changes in network needs and how they meet the qualifying criteria for early competition. This will also provide clarity to stakeholders along with accountability for facilitating early competition on distribution networks – enabling a clear assessment to be made of how effective DNOs have been in embracing the DSO roles. DNOs can then be judged objectively on their performance in this area and we consider that it would be helpful to have DSO ODI metrics assessing this performance.

However, we are concerned that Ofgem has asked the ESO to assess what role it could play in facilitating early competition at distribution level, as part of its early competition plan. Bringing the ESO in to run these roles risks duplicating the DSO activities DNOs will already be undertaking around planning and network development, resulting in increasing costs to consumers. It would be confusing to stakeholders and risks splitting accountabilities. Consequently, we will be working closely with the ESO on its early competition plan, to ensure that the outcome is efficient for customers.

COQ43. Do you agree with our proposed approach on early competition?

In principle, we support early competition where it benefits customers. However, as Ofgem acknowledge, the proposals in the SSMC require more development and at this stage it is difficult to provide material comments on the approach. At this stage, we would make the following observations:

- Value threshold: We agree with Ofgem's observation that the value and time horizon of many projects considered by the DNO are unlikely to be appropriate for early competition. This should not be a reason to change the criteria or thresholds and we agree that it should be focused on high value projects. Consequently, the value threshold of £50m (as proposed in RIIO-GD2 and RIIO-T2) seems appropriate.
- Time criticality and certainty of system need: We agree that additional criteria around the time window required for a project to be eligible for early competition would be helpful, given the lead times to run an early competition tender. As highlighted in our response to COQ42, we will be looking to identify network needs up to 5 to 10 years ahead of time. However, these needs are likely to change year on year, making it difficult to provide certainty of need too far in advance. Therefore, there may be tensions between criteria around time criticality and certainty of need, with guidance required on the appropriate balance of the two.

- Alignment with DSO roles: As highlighted in our response to COQ42, the DSO functions and activities we are developing around Planning and Network Development align well with the requirements to set out network needs at an advanced stage, to facilitate early competition. We will work with the ESO to ensure that these roles are adequately reflected in its early competition plan and that there is clear allocation of responsibilities between ESO and DSO.

COQ44. Do you have any views on our draft RIIO-ED2 Late Competition Impact Assessment?

We are concerned with the lack of detail presented in the impact assessment. By Ofgem's own admission they have made some high-level assumptions and have not yet developed a robust and quantifiable evidence base to make any decisions. For example, Ofgem has assumed electricity distribution is the same as transmission but is unclear how valid this is. Further, Ofgem has focussed on costs but there is no detail on benefits beyond a very high-level qualitative statement that lacks evidence. We therefore believe more work is required to understand how Ofgem's late completion models would bring benefits to DNOs' customers.

COQ45. What are your initial views on the three models of late competition (CATO/CADO, SPV and CPM) in the context of electricity distribution? If there would need to be differences from the other sectors, can you please explain what these should be, and why.

Based on the current evidence available we do not believe these models are currently appropriate for electricity distribution. These models have not yet been successfully delivered at transmission, which is where they were intended for use, hence there is no logic in applying them until they are proven at that level.

As an example of the lack of applicability, Competitively Appointed Transmission Owner (CATO) projects feature a single generator, a single asset and a single customer; whereas electricity distribution level projects are all likely to feature more complexity.

There are a number of details that would need to be agreed for this to work successfully, for CATO/CADO and SPV models:

- Which party will assume responsibility for network performance issues relating to third party assets? For example, will a third party take on responsibility for customer interruptions and minutes lost downstream of their asset? The approach to this question should take into account both providing appropriate protection for customers with avoiding DNOs carrying the risk for third party performance.
- How will any cost outperformance or underperformance by third parties be shared with customers? Will third party providers be subject to a similar totex incentive mechanism to DNOs, in particular to mitigate the impact on customers if a project is delivered for more than the price set based on a competitive process? This could take the form of a project specific incentive for CATO/CADO operators, or some form of pass through with an SPV.
- How will future additions to the network be addressed? Networks grow organically over time, which could involve the need for additions to third party assets or changes around them in the network. Will a third party receive the exclusive right to operate the network in a given service area, or will further coordination with other parties be included as an obligation?
- How will late competition interact with existing mechanisms for competition in connections? The 'separable' criteria may mean it is appropriate to bundle some aspects of contestable connections work into a project for late competition. The contestable boundary for competition in connections may in some areas need to change to enable an appropriate packaging of work for later competition.

Further details necessary for implementation of the SPV model include the protection in place for DNOs from regulatory risk arising from contracting with a third party. We anticipate back-to-back arrangements would be used to replicate the DNOs' licence obligations for the SPV. However, unlike the CATO/CADO model, it will not be possible or appropriate to pass on these obligations fully via a contract to a third party. One example is performance under more qualitative incentives (e.g. the vulnerability ex-post incentive Ofgem propose), which could not be completely covered by a contractual relationship.

The allocation of other risks should be considered and compared against a more traditional native competition approach. For example, counterparty risk, would DNOs remain able to step in and take control of a project from an SPV if performance was below an acceptable threshold?

Given the experience of the Competition Proxy model to date, we are sceptical that there would be any benefit in introducing this model into the electricity distribution sector.

COQ46. Do you agree that the late competition models proposed could deliver benefits in RIIO-ED2?

We are yet to see compelling evidence that the late competition models proposed would deliver benefits in RIIO-ED2. Therefore, in our view more work is required to understand what an optimal model looks like for electricity distribution.

Through, for example totex and a focus on native competition, we believe customers have reaped the rewards of competitive forces. We have concerns that a shift to other, unproven, competition models will undermine the current progress being made and could create unnecessary complexity.

Furthermore, we do not believe it is in the interests of consumers to move away from a model that maintains clear accountability with respect to network planning and operational decisions. An example to illustrate the non-suitability of applying a model that puts competition ahead of performance regarding high volume, lost cost interventions, is through the demise of Railtrack.

As a result of the separation of ownership and maintenance of rail track the rail sector was plagued with delays, under investment and a poor maintenance record, all of which negatively impacted consumers. This was not only through level of service but also through tragic accidents such as the Southall, Ladbroke Grove and Hatfield crashes. More recently the Department of Transport's 'Strategic Vision for Rail'[46] recognises the fact that separation of different services results in poor performance for the customer when "things go wrong, energy and time which could be spent on solving the problem can be lost in contractual debate and industry dispute processes."

To summarise, we believe that any approach to encouraging competition must ensure:

- The complexity of the process used is proportionate to the value and time-sensitivity of the project or system need;
- There is clarity between delivery and ownership/operation of assets;
- The recovered costs are split equitably across current and future customers;
- The methodology to encourage competition does not unduly favour third parties through allowing differing financing arrangements or lower standards;
- That the licensee who is best positioned to deliver a customer outcome can be allowed to do so by enabling outputs and allowances to be transferred;
- Network operators are appropriately incentivised to search out efficient and innovative solutions to projects/system needs; and
- There is a level playing field between different parties competing for new connections.

COQ47. Do you agree that our proposed criteria for identifying projects suitable for late model competition are applicable in the context of electricity distribution?

We agree that the same criteria should be applied from transmission in terms of value thresholds.

COQ48. What are your views on the best ways to identify a suitable project pipeline for late competition in electricity distribution (eg our proposal to require flagging of projects that meet the high-value, new, and separable criteria)?

We agree with the approach proposed and that it is appropriate to publish a list of projects to build interest from third parties, which could be part of a DNO's business plan.

We already publish Regional Development Plans and a Long Term Development Statement on an annual basis, and we could build on these to update the pipeline of projects to consider for competition each year.

One factor to be aware of is that the network is dynamic, and the pace of change will increase as the energy transition accelerates in RIIO-ED2. Therefore, we anticipate that the pipeline would need to be able to flex with each iteration.

[46] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/663124/rail-vision-web.pdf

COQ49. Do you agree with the proposed range of options available for repackaging projects in RIIO-ED2 in order to maximise consumer benefit?

We are currently unclear on what Ofgem is proposing on this and have concerns regarding its potential implications.

Any ‘repackaging’ could have significant impacts on customers therefore we seek further detail on how this would work as a matter of urgency. Unless these projects were located together and met certain criteria we cannot see how this would work in practice

The re-packaging of projects risks undermining the well-established criteria which Ofgem has used to assess where the Late Competition model can provide benefits. We also note that the Impact Assessment is based on these criteria and may not be valid if Ofgem intend to package up projects.

Rather than provide customer benefit, there is a risk that repackaging leads to delays in getting vital infrastructure delivered, while assessments on suitable packages are reached. In areas of rapid Electric Vehicle (EV) uptake, these delays could have real impacts for consumers and decarbonisation targets.

COQ50. What relevant factors do you think we should consider in deciding how these repackaging proposals are specifically applied in electricity distribution?

In line with our response to COQ49, we seek clarity on what Ofgem is proposing and how this would be achieved in practice. Due to the lack of detail Ofgem has provided we are unable to give a view on all of the factors that need to be considered. It would be particularly useful if Ofgem could outline an example/use case of repackaging alongside an assessment of the potential benefits it could provide to customers.

25. Incentivising Business Plans and their Delivery

COQ51. Do you agree with our proposed approach to implementing the CDIR method in setting the TIM efficiency incentive rate?

As we stated in our response to Ofgem's open letter consultation, the Totex Incentive Mechanism (TIM) is the principal vehicle for driving companies to seek and realise cost efficiencies. The TIM empowered companies to take their own business decisions, allowing them to decide where best to innovate, outsource or indeed develop new markets such as flexibility. In RIIO-ED1 to date, our innovation alone has led to £232 million customer savings. TIM has demonstrably proved a powerful way of encouraging network companies to deliver their outputs at lowest cost.

CDIR and cost confidence

The key, and proven, requirement to drive more innovation and competition is a strong efficiency signal through a suitable sharing factor and a totex allowance that is linked to outputs alongside appropriate Ums. While we note Ofgem highlights the regulatory precedents for a 50% sharing rate, in the case of RIIO-ED2 that rate is being used as an upper limit rather than as a single point figure or the centre of a range.

The combination of the CDIR approach and Return Adjustment Mechanisms risks significantly blunting this incentive and will weaken the pressure on companies searching for cost efficiencies as the rewards may not outweigh the risks.

Ofgem is concerned about the prospect of companies earning unfair returns. However, our view is that that the RAM in isolation, if calibrated appropriately, is sufficient to achieve Ofgem's goals around fair returns, particularly given the greater range of performance incentives in this sector compared to gas distribution and transmission. The RAM provides adequate assurance of fair returns without the need for a reduced totex incentive rate.

If Ofgem decide to proceed with the CDIR approach, Ofgem should ensure companies have every opportunity to provide Ofgem with confidence in cost benchmarks and secure a sharing factor that supports ambitious delivery for customers.

Ofgem is looking for companies to provide independent benchmarks to support a claim for high confidence costs where such confidence is not provided under the regime. We assume that Ofgem's ability to compare costs between companies will, all else equal, result in cost confidence being assessed as "high". It would help companies if Ofgem were to be explicit about the level of confidence it takes from its own benchmarking. Ofgem should also be clear about what kind of evidence it would consider persuasive and useful in making this assessment in cases where it is not easy for it to compare costs.

Companies will not have the same level of confidence about DSO costs given there is not a long track record of such costs and it is a fast-moving area. Benchmarking costs between companies should give some confidence but Ofgem should take the relative newness of this area of costs into consideration in applying its cost confidence tests in this area.

We would also like clarity in other areas of the price control, such as on the use of uncertainty mechanisms and treatment of strategic investment. Lack of clarity about how these mechanisms work and interact will have an impact on our level of confidence about costs of baseline expenditure. It is unclear how Ofgem might assess cost confidence in cases where companies adopt different approaches (i.e. base or UM) to similar costs. It is also not clear how expenditure which may be allowed for during the price control under an uncertainty mechanism will impact, if at all, the CDIR.

COQ52. Do you agree with our proposed design of the BPI for RIIO-ED2?

The over-arching four stage design of the BPI appears to have some merit in principle. It makes sense to require minimum standards to be met (Stage 1) before contemplating reward for ambition (Stage 2). The approach to assessing cost (Stages 3 and 4) seems reasonable.

We set out below some general concerns about the approach but before doing so we highlight two areas where we are not clear about the design.

Clarification points

First, where the costs are excluded on the basis of poor justification at Stage 3, will that mean that they are also not counted as low confidence costs when calculating the CDIR? This would mean that companies are not penalised twice by having both the costs disallowed and via the lower level of confidence. We would welcome confirmation on this point.

Second, in Figure 9 of Annex 2 of the SSMC, Stage 4 says "CDIR on ambitious costs vs independent benchmark (high confidence costs only)". The reference to CDIR is confusing. Our understanding is that the CDIR is calculated based on the ratio of high confidence to total costs and that Stage 4 allows for a potential additional reward for the revelation of costs below benchmark.

We seek clarity on both of these points.

General comments on the BPI and CVP

For the BPI to work it needs to be calibrated well and implemented effectively. The BPI is similar to that used for the RIIO-ET, RIIO-GT and RIIO-GD controls. However, the recently published Draft Determinations only partially delivered on the objectives of the mechanism. There are very large penalties and virtually no rewards. It is difficult to see how an outcome like this, if repeated, would provide good balanced incentives to bring forward ambitious proposals. It appears that the plans did contain a number of proposals which looked ambitious but that in many cases these were disqualified as being inadequately justified. Therefore, in the case of the other network companies it has not been implemented in a way which instils confidence that ambitious proposals will be rewarded. We are therefore concerned to avoid such an outcome for RIIO-ED2. (Please also see our response to COQ54 for our views on the cap, which is a change for the RIIO-ED2 proposals compared to the other sectors' draft determinations).

The idea of a BPI to encourage ambitious plans is a good one. However, it needs to genuinely encourage and reward ambition, not just be seen as a penalty regime for not meeting a pre-defined standard.

We have identified six factors which the design needs to address:

1) Baseline requirements

Stage 1 of the BPI is about the achievement of "baseline requirements". We take this to mean that this is genuinely a baseline test – in other words that what is defined as "baseline" is not subsequently interpreted at an unreasonably high standard, for example a standard approaching "best practice". We believe it is also reasonable to expect that the baseline is an achievable level, a bar which all companies would be aiming to exceed. We are not yet assured about this unless it is only to be applied to areas where baseline standards have been set out in Business Plan Guidance.

Achieving the baseline standard broadly involves the business plan passing two separate tests: it should be complete and be of satisfactory quality.

- The requirement for a complete submission is that all required information is included in the Business Plan. It is helpful that the Minimum Requirements Information Sheet (MRIS) specifies the paragraphs in the Business Plan Guidance that must be met to achieve minimum requirements. Ofgem should explicitly confirm that this is indeed the complete list and that a business plan which provides all of the required information listed in the MRIS will be considered to have met this test.
- The requirement for satisfactory quality is further defined in four ways:
    - "sufficient" evidence,
    - "credible" delivery plans,
    - inclusion of commitments for safeguards, and
    - subject to enhanced engagement challenge.

  Most, if not all four of these criteria are fundamentally matters of judgement. While we note and welcome that Ofgem will consider the materiality of any "failures", there is no information on what would constitute a quality failure. Clearly there is a balance – it would be impossible to define very precise rules. Further dialogue between Ofgem and the companies would help to clarify what would constitute a failure and doing so early would help avoid unnecessary costs and friction at later stages.

2) Understanding Business as Usual and Baselines

The purpose of Stage 2 of the BPI is to reward companies for proposing initiatives and plans which are ambitious and provide value for customers. This is desirable. However, it is not clear what standards will be applied in making

this judgement. The Business Plan Guidance suggests that successful proposals should go “beyond functions which are considered as business as usual” and should exceed baseline standards in one of five specified areas. This perhaps demonstrates that there is a general need to clarify exactly what standards will be applied in evaluating CVP proposals.

It also raises questions about how the baselines in the specific areas will be finalised and applied. We would be concerned if the baselines become “the best of the best” which would risk them not being appropriate to all companies’ circumstances (or in line with the views of their customers). We comment in more detail on the approach to setting of baselines in our response to COQ53.

We think that all parties will benefit from some further clarity on how CVPs will be assessed and the criteria for doing so. The benefit of this would be that companies may better justify their CVP proposals, making the evaluation process more efficient

Whilst it is helpful that Ofgem have identified the five specified areas to focus CVP proposals on, we currently believe there may be merit in permitting the evaluation of a limited number of initiatives which are outside these five areas, if they would provide value to customers and are well justified. In such cases a higher evidential bar may be warranted to ensure that Ofgem is not inundated with “off-piste” proposals.

3) Size of CVP reward

Ofgem is keen that the reward gained by companies is linked to the level of value that may be delivered by the proposal. This seems valid in principle but in practice is problematic because deriving the value of benefits is inevitably difficult and subject to uncertainty. This is true however theoretically well-justified the methodology (for example, using stated preference studies or Social Return on Investment (SROI)).

Our reading of the BPI as it applied to the recent Draft Determinations was that there was an issue with the commitment to base the CVP rewards mechanically on a calculation of net customer benefit, whether that was calculated using a CBA approach or using SROI. A mechanical application of the method potentially puts very large rewards in play.

Some way of scaling the rewards would therefore seem to be important and the SSMC appears to envisage this. However, it is not clear exactly what Ofgem means when it states that rewards will “be commensurate with the level of additional value” and that reward would “scale to the level of additional consumer value that the plans offer” (SSMC Annex 2, para 13.24). We would welcome clarity from Ofgem in terms of what this means and how it intends to calculate rewards.

4) Importance of “in the round” assessment

It would seem desirable to consider companies proposals “in the round” as well as considering the merits of looking at each CVP proposal in isolation. An “in the round” assessment should provide some recognition and incentive to companies that can demonstrate that ambition to achieve good customer outcomes is embedded within their business culture. Furthermore, an “in the round” assessment may enable some judgement to be taken on the overall level of risk to delivery for customers across their proposals.

The idea of how to scale rewards could be resolved by setting the level of rewards based on an “in the round” assessment of the company’s overall ambition as demonstrated by its CVP proposals. This would necessarily involve some element of judgement which would moderate the mechanical equivalence between value calculation and reward but is nonetheless structured and provides some basis for application of judgement.

For example, there might be a scheme in which Ofgem:

- Defines criteria for determining the CVP, including the value of the benefits from company commitments;
- Grades the CVP in business plans as one of five levels – very poor, poor, fair, good and excellent; and
- Then, awards the companies a pre-determined percentage of revenue for level of grading, e.g. 0% for “very poor” and X% for “excellent”.

This could be used to determine the overall level of reward directly, with individual CVP proposals being considered to inform the judgement of whether the criteria have been achieved or not. Alternatively, the method might be used to scale up or down the CVP awards for individual proposals.

Ofgem might also consider:

- Using a calculated benefit value or a proportion of it as an upper limit to the reward; and
- Considering the value generated per £ spent as well as the net value in total in assessing the reward payable so that smaller initiatives with a large "bang for buck" are not ignored.

Ofgem has proposed an overall cap on the number and value of CVPs which is relevant to this. See our comments on Q54 below.

5) The benchmark for justification of a CVP

It is noticeable in the recently published Draft Determinations that many CVP proposals have been disqualified because the investment or business plan proposal associated with it had not been sufficiently well justified. There may be some CVP proposals for which a company is not asking for any up-front funding and which do not have such direct links to the base determination of allowances or as an ODI but which nonetheless could constitute an ambitious proposal which might warrant recognition.

COQ53. What are your views on our suggestion to use proposals contained in draft business plans in the setting of baseline standards in a number of areas?

As outlined in response to earlier questions, we have significant reservations about how companies' business plan submissions would be used to increase baseline standards post business plan submission. It may lead Ofgem to take best practice as a baseline standard. Clearly the use of best practice suggests a standard well beyond what could be considered the "acceptable consistent approach" that a baseline perhaps should represent.

We would therefore do not support Ofgem moving the bar post submission.

If Ofgem remain wedded to this proposal we believe further discussion is warranted to mitigate the risks we have identified in our response.

COQ54. Do you agree with our proposal to cap the number and value of CVP proposals that can be included within business plans?

Yes. As we have noted in our response to COQ52, the mechanistic translation of benefit values to rewards is problematic.

Ofgem also observed that companies responding to the CVP appeared to include long lists of potential CVPs some of which looked rather speculative (a "kitchen sink" approach). In the light of these, we see the introduction of the overall cap and the minimum and maximum values for individual CVPs as a way of ensuring the CVP arrangements are applied in a proportionate way.

The intent of this proposal appears to be to limit the potential reward that customers would need to bear. It also provides the impetus for companies to ensure that they only put forward the best of its proposals and thus to self-regulate its CVP proposition. This is a sensible aim.

We agree that limiting the number and having a minimum value of individual proposals will help to focus submissions and reduce the burden of assessment which is desirable. The limits are of course slightly arbitrary so there is always the risk of rewarding a company for a CVP proposal that is objectively inferior to a proposal from another company that has simply hit the cap. We assume that the limits presented in the SSMC are intended to be applied to each individual licence rather than at a DNO group level but would welcome confirmation of this. This does also lead to a question of how the individual limits would be applied to combined CVP proposals from a company where the proposal relates to multiple license areas, we would welcome further clarity in this area.

However, there is an important further point about scale which should be considered. Limits fixed in value terms could have a differential impact on large and small companies. Therefore, a CVP which drives value for all customers will by definition provide a greater aggregate value when a company is large and has more customers then when it is small and has fewer customers. This can be avoided by relating the limit to a scale variable. This does not need to be complicated: relating the limit to the number of customers served by a company would seem a sensible approach. Applying the limit at the level of the network rather than the whole company could also be considered to enable consideration of proposals which may be region specific where warranted.

We are unconvinced with the proposal to define a maximum "value" for each CVP element. What seems to be important is to limit the amount which customers are expected to pay, rather than the value deriving from it per se. As we suggest above, there are likely to be difficulties in confidently determining value. We therefore think that any

limit on individual CVPs should be applied to the level of reward. Our response to COQ52 sets out some ideas about how reward might be linked to value.

COQ55. Is there any further detail on the proposed content of the Business Plans that you think should be set out in the Business Plan Guidance?

We have set out above, in our response to COQ52, what would be useful to explain in terms of minimum requirements. We do not see any other major omissions.

One specific point that we would like Ofgem to consider is the treatment of different operating licensees in terms of information provision and business plan content. We have three licensees, each of which has specific characteristics and needs. We already see customer views varying and would expect this to be further demonstrated as we conduct our stakeholder research programme.

COQ56. Is there other information that we should be requesting in the Business Plan Guidance in order to assess a network company's Business Plan?

For the most part the information requirements seem comprehensive. However, we would welcome further clarity on how Ofgem intends to use the information it receives as it is not clear in all cases.

One area we would like to see more guidance is on customer and stakeholder engagement. We would like to see more clarity on how Ofgem will evaluate companies' customer and stakeholder engagement in order for us to understand what Ofgem might consider as 'robust and high-quality engagement'. Other regulators, such as Ofwat at PR19, set out clear standards and guidelines for what it considered to be best practice. We would welcome Ofgem adopting a similar approach and work with licensees and stakeholders ahead of SSMD could prove beneficial in this area.

We also think that Ofgem should include more in its guidance about how it will judge companies' engagement and how it will use the outcomes of engagement in making its decisions. Customer and stakeholder engagement is a clear strategic priority for us. It is clearly essential that we do high quality engagement and we are clear that this has fundamental purpose which is to enable us to best deliver for customers and enable us to achieve our strategic goals. In other words, engagement is not just to serve a narrow regulatory purpose in the context of a price determination. However, the outcomes of the price determination will impact what we do for our customers. We need to account for this to our customers and to do this we need to give them confidence that their investment in the stakeholder engagement process is valuable. We therefore think that Ofgem can and should say more now about how it intends to use the outcomes of customer engagement and how it will be transparent about that.

COQ57. Do you agree with the proposed set of minimum requirements for Stage 1 of the BPI that are set out in the draft Business Plan Guidance?

We have set out our views on minimum requirements as a concept in our answer to COQ52 above. We have no comments on the specific items listed in the MRIS.

COQ58. Do you agree with the approach for assessing companies CVP proposals that is set out in the draft Business Plan Guidance?

We have set out our views on the assessment of CVP proposals in our responses to COQ52 and COQ54 above.

COQ59. We anticipate that DNOs are investing in improving / creating data dictionaries and business information models that describe the data-driven aspects of DNOs overall business architecture. We anticipate there may be opportunities to take advantage of these investments to support the process of cross-referencing data used within RIIO-ED2 Business Plans. What are your views on this?

In principle we support the development of data dictionaries and business information models where they demonstrably provide benefits. Our initial reaction is that this type of activity would be covered as part of DNOs' digitalisation plans and should be business as usual. If, however, Ofgem sees a need to obligate DNOs to do this we would welcome further detail and consultation on what exactly is expected.

If it is seen that the creation of data dictionaries and new business information models can be used to validate RIIO-ED2 plans then the timings around this need to be clear.

As a wider point, we are keen to receive guidance from Ofgem on how DNOs will get the level of endorsement and funding required to drive this type of activity. As this also is not a straightforward task there is a risk of being pushed to develop a data dictionary that may do little to fulfil ambitions.

QUESTIONS IN SSMC ANNEX 3 – FINANCE

26. Allowed Return on Debt

FQ1. Do you agree with our proposal to use the iBoxx Utilities 10yr+ index rather than the indices used in RIIO-1?

We believe that it is premature to state that the IBoxx Utilities 10yr+ index is the appropriate index for electricity distribution. As we note in our answer to FQ3 the embedded debt profile of the electricity distribution industry is different to that of both gas distribution and transmission.

We would also note that the Utilities index has no specified rating other than investment grade whereas the iBoxx A and BBB corporate indices are regularly updated to include only A or BBB bonds respectively. The choice of index is important as it should be linked to the notional company target credit rating. As the Utilities index is limited to investment grade rating, rather than to A or BBB, then there is a greater risk of mismatch between the notional company credit rating and the cost of debt allowance.

FQ2. With reference to paragraph 2.8, do you have a view on what debt allowance calibration should be used for business plan working assumption purposes, and why?

At this stage we believe that Ofgem should maintain the existing RIIO-ED1 10-20 year trombone. As Ofgem notes it will only be on receipt of the Business Plans that it will be able to ascertain the appropriate index to set the cost of debt for the electricity distribution sector and until it has this information we believe that Ofgem should maintain its current assumption.

Ofgem should not automatically assume that the current 10-14 year proposal for the gas distribution and transmission is applicable to electricity distribution. As was demonstrated in RIIO-ED1 the index used for gas distribution and transmission was not appropriate for electricity distribution.

FQ3. Do you have any evidence to suggest ED networks should or should not have a debt allowance that has a different calibration to GD&T networks?

As was highlighted at RIIO-ED1, the historic debt portfolios of the electricity distribution sector meant that a different calibration of the cost of debt index had to be employed. With respect to the gas distribution sector the majority of the debt was taken out in 2007, at the formation of the GDN companies, whereas in electricity distribution sector there a number of companies with debt raised in the 1990s when debt costs were significantly higher. It is therefore unlikely that the same index would be applicable.

FQ4. Do you have any views on our analysis of additional costs of borrowing that may not be captured by an index of bond yields?

We believe that there are two areas of additional costs that Ofgem have not properly considered. These are:

- **New issue premium:** In its previous report for the ENA, NERA[47] had identified that Ofgem's approach to calculating spreads, for estimating the HALO effect, was incorrect as it did not correctly adjust for tenor differences. In its most recent report for the ENA, NERA[48] has addressed Ofgem's issues with respect to duration matching and still finds that a new issue premium of circa 10bps can be justified. Given the current illiquidity of the Consumer Prices Index (CPI) linked debt market we would expect new issue premiums to be significant.
- **Additional cost of CPI debt:** In its draft determination for the Gas Distribution and Transmission companies, Ofgem rejected making an additional allowance associated with either the basis risk associated with RPI index linked debt held by companies or raising CPI debt by asserting that:
    - The basis point differentials between RPI and CPI swaps are low single digits and hence not material;
    - Additional CPI index linked debt is not required for the notional company as the Gas Distribution and Transmission sectors are already operating above the assumed notional level of index linked debt; and

[47] NERA (September 2019) Halo effect and additional costs of borrowing at RIIO-2, A report for ENA.
[48] NERA 'Review of Ofgem's DD Additional costs of borrowing, and deflating nominal iboxx' Prepared for ENA September 2020

- The basis risk liability with respect to existing RPI linked debt is mitigated by the RPI-CPI wedge in the short term with negative impacts in the medium term on leverage metrics.

With respect to the first point if companies are raising significant amounts of new debt this differential could equate to significant expenditure. On the second point companies may have to refinance a proportion of their existing index linked portfolio and hence will be exposed to the additional costs of raising CPI linked debt. The implication of Ofgem's last point is that that even if it is an issue then it is mitigated in the short term at the expense of future customers. We do not see how the latter is protecting the interests of future customers. In addition, as NERA show there is still a risk in the short term if the actual RPI-CPI wedge outturns significantly differently than Ofgem's forecast used to set the cost of debt.

FQ5. Do you agree with our proposal to use the longest term OBR forecast for CPI to deflate nominal index yields to a real CPIH allowance and to switch to using OBR CPIH forecasts if these become available?

We believe that a better approach would be to use the average of the HMT Treasury consensus CPI forecast as this contains a range of forecasts developed by a number of independent forecasters. The RPI forecast from this dataset is already used within the RIIO-ED1 price control to set the inflation assumptions for allowed revenue. We also believe that this forecast should be trued up for actual outturn CPI inflation. This would ensure that the approach to the cost of debt is aligned with that used for allowed revenue.

27. Allowed Return on Equity

FQ6. In light of the equity methodology we set out in Draft Determinations for GD&T, do you have a view on how implementation could best be applied to the ED sector?

We believe that there are significant issues with Ofgem's approach to determining the cost of equity. Ofgem recognises that electricity distribution companies are pivotal to enabling the UK to achieve its 2050 Net Zero target and as such investment will need to rise. It is therefore vital that the cost of equity is a set a level that will attract the required investment into the sector, both for RIIO-ED2 and in the longer term.

Our key issues with Ofgem's approach to the cost of equity, and more broadly how it determines its cost of capita are:

- The application of an outperformance wedge;
- The approach to determining a point estimate for the cost of capital; and
- Methodological issues with the calculation of the components of the cost of equity

Each of these is discussed in more detail below.

The application of an outperformance wedge

We remain opposed to Ofgem's proposal to reduce the estimated cost of capital for expected outperformance in RIIO-2. In its report for the ENA, Frontier Economics[49] have identified issues with the quantification of the outperformance wedge. However, our key concern is with the principle of adjusting the cost of equity, the incentive to invest, for perceived forecast outperformance. If Ofgem can robustly identify that an element of the price control could lead to excess outperformance then Ofgem should adjust the targets in that element of the price control not the cost of equity. If Ofgem implement this approach then we believe it would significantly erode investor confidence and hence increase investor risk. This must ultimately increase the cost of capital which would be an issue for all customers.

The approach to determining a point estimate for the cost of capital

In determining the cost of capital Ofgem has to choose where in the range its point estimate is located. In its Draft Determinations Ofgem has effectively aimed down by reducing its mid-point estimate by the outperformance wedge. We believe there is a case for Ofgem selecting a point estimate above the mid-point of its cost of equity i.e. aiming up. In its report for the ENA Frontier Economics states

> "In *the absence of certainty around the **required** rate of return, the **allowed** return needs to match (or exceed) the required return for investment to be viable. However, due to the high level of uncertainty around, in particular, the cost of equity, there is no guarantee that the midpoint of a best-endeavours and reasonably judged range would turn out to be at or above the right level to satisfy this constraint. In this environment, given the asymmetric consequences of failure to invest, aiming up is an optimal regulatory response to the uncertainty inherent in estimating the cost of equity and the asymmetry of the consequences arising from setting the allowed return too high or too low."*

We agree with this position. Setting the cost of equity too low may result under-investment e.g. in slower investment to decarbonise the economy which ultimately will result in societal detriment to both today's and tomorrow's customers.

[49] Further analysis of Ofgem's proposal to adjust baseline allowed returns, Frontier Economics, 2020.

Methodological issues with the calculation of the components of the cost of equity
We believe that there a number of significant methodological issues with Ofgem's approach to calculating the key components of the cost of equity: These are summarised below with the detail presented in the OXERA report[50] prepared for the ENA.

Risk Free rate
OXERA have identified two key issues with Ofgem's proposed approach to calculating the Risk Free Rate. They are:

- **Index linked Government bond yields underestimate the risk free rate that should be used in the Capital Asset Pricing model:** The reason for this is that Government bonds possess special safety and liquidity characteristics compared to other securities. Consequently, this pushes the yields on government bonds below the required rate of return for a zero-beta asset.
- **The CAPM assumes that all investors can borrow at the same risk free rate:** In reality even the most credit worthy company cannot borrow at the same rate as governments.

The alternative proposed by OXERA is to use the yields of AAA corporate bonds as proxy for the risk free rate, adjusted for the fact that there is a non-zero probability of default. As a cross check OXERA have also modelled applying an uplift to government gilts which is an approach used by equity analysts to estimate the risk free rate. Based on current data calibrating across both of these approaches would produce a risk free rate of circa -1.0%, compared to Ofgem's current assumption of -1.48%.

Total Market Return (TMR)
We remain of the view that an analysis of ex ante historical returns are the best approach to calculating the TMR. We also note that this is the CMA's preferred approach. The two key issues with calculating the TMR relate to:

- The appropriate inflation index to use to deflate the ex-ante nominal returns; and
- The use of either geometric or arithmetic averages to determine the TMR estimate.

With regard to the former we believe that adjusted RPI data series remains the best approach to deflating the nominal returns. The alternative CPI data series is a modelled view and it is a concern that the Office of National Statistics cannot reproduce this dataset. In our opinion this must be taken into account when placing any weight if it is used in determining the TMR.

On the second point we believe that arithmetic averaging remains the appropriate approach. As demonstrated by Cooper (1996)51 the discount rate investors should use to give an unbiased estimate of the present value of future cash flows will assume a TMR at least as high as the arithmetic average of historical returns.

The use of cross checks on the TMR
We remain concerned that Ofgem continues to cross check its CAPM derived Total Market Return to the returns listed by investment managers, offshore transmission operators (OFTO) and Market to Asset Ratio premia. In its report OXERA have highlighted that:

- The TMR estimates produced by investment managers have the primary purpose of providing prudent estimates of future returns to their clients, to ensure that clients are managing their finances prudently. This is mainly a function of the regulatory framework, namely the FCA Conduct of Business Sourcebook, section 13, which states the maximum rates of return that financial services companies must use in their calculations when providing retail customers with projections of future benefits:
- OFTO projects are operational assets with a very different risk profile compared to the onshore energy networks regulated by RIIO-2. In particular, the net cash flows are largely fixed in real terms over the duration of the OFTO tender revenue stream; and
- Ofgem/CEPA assume that observed premia are driven by two factors: outperformance and a market cost of equity that differs from Ofwat's allowed return. This analysis ignores several other drivers of listed asset premia, including (but not limited to) the values of the non-regulated businesses, investor expectations of future dividends, and expected takeover premium.

[50] The cost of equity for RIIO-2:Q3 2020 update, OXERA, 2020.
[51] Cooper, I. (1996), 'Arithmetic versus geometric mean estimators: Setting discount rates for capital budgeting', European Financial Management.

We remain of the view that limited weight should be placed on these cross checks. One area that we believe Ofgem should more explicitly consider is the differential between the Asset Risk Premium (ARP) and the Debt Risk Premium (DRP). OXERA have updated their analysis for the ENA and the key conclusions of the report[52] are that RIIO−2 cost of equity allowances in the Draft Determination falls below that implied by:

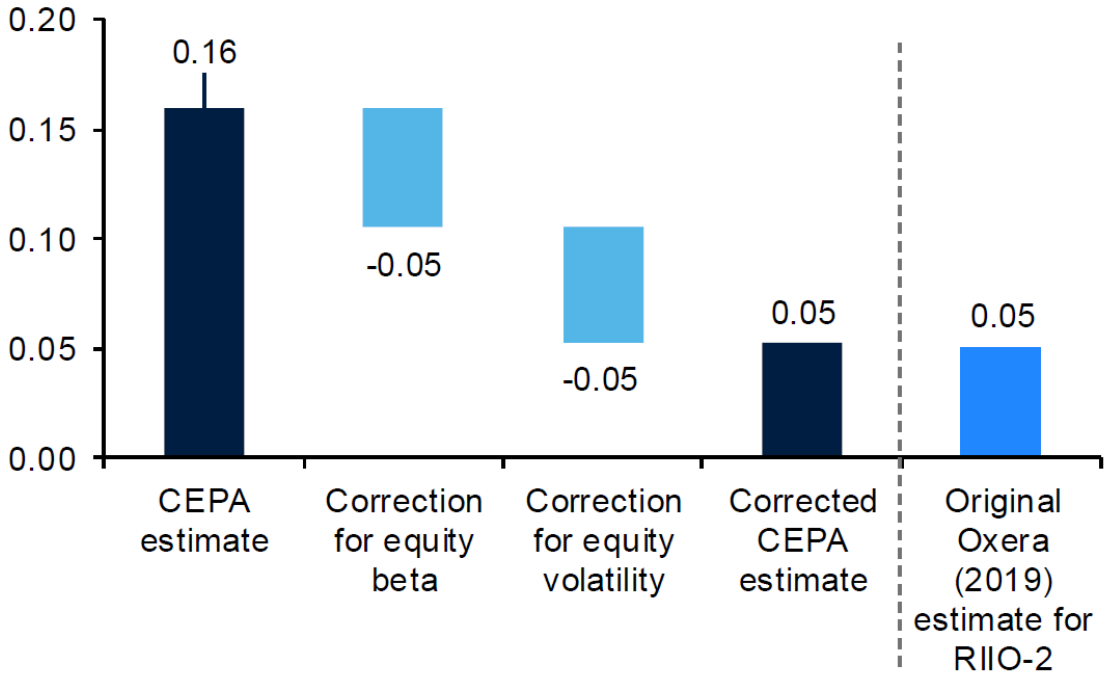
- contemporaneous market evidence for the cost of debt and the risk-free rate; and
- a mixture of contemporaneous market evidence and regulatory precedent on the asset beta and the TMR.

In fact OXERA's analysis shows that the ARP-DRP differential implied by Ofgem's Draft Determination proposals lies in the bottom 15% of the empirical distribution of that implied by relevant market evidence (e.g. traded yields of energy bonds over the six-month period preceding the RIIO−2 Draft Determination). This is at odds with previous regulatory determinations such as RIIO-1 where the ARP-DRP differential was broadly in line with those implied by contemporaneous market evidence around the corresponding determinations.

Debt and asset beta

In its cost of equity report for the ENA OXERA have highlighted that Ofgem and CEPA have made a number of errors in calculating the appropriate debt beta, and if these are adjusted for then the analysis is line with OXERA's estimated debt beta of 0.05. An example of this, in relation to CEPA's calculation of debt beta using a structural approach, is shown below.

Figure 6: Correcting CEPA's structural debt beta estimate



We remain of the view that a debt beta of 0.05 is more appropriate than Ofgem's current proposal of 0.125. On equity beta our key concern is that energy networks are exposed to greater risks than water companies principally due to their role in enabling the decarbonisation the UK economy by 2050. We believe that the weighting of the asset beta dataset towards listed water companies will underestimate the asset beta for energy companies. Therefore, we agree with OXERA that it would be beneficial to expand the comparator datasets to include the European energy utilities proposed by OXERA given that these companies derive the majority of their revenues from European regulated activities. Based on a debt beta of 0.05 this would result in an asset beta range of 0.38 to 0.41.

[52] Asset risk premium relative to debt risk premium, OXERA, 2020.

FQ7. Do you have suggestions on how we could estimate systematic risk for ED2 or any evidence to support a difference between ED and the other RIIO sectors, GD&T?

We believe that the risk profile of electricity distribution will change in RIIO-ED2. The reasons for this are:

- **The impact of the creation of the DSO role in RIIO-ED2:** The DSO function will introduce a new range of roles and responsibilities and as such may increase the risk that companies face. The cost of equity determined for the ESO may be an appropriate benchmark to determine the impact on electricity distribution network companies. We note that the asset beta assumed for the ESO of 0.45 is higher than that assumed for either the gas distribution or transmission network operators of 0.365 (midpoint of Ofgem range);
- **Impact of increasing investment:** There is a general acceptance that investment in electricity distribution networks will have to increase in the RIIO-ED2 period, and beyond, to facilitate the Net Zero transition. This increased expenditure is likely to increase operational gearing and hence risk and as such an analysis of the movement in operational gearing may be an appropriate methodology to quantify this. We note that the CMA[53] has previous taken into account increases in operational gearing when determining the cost of capital; and
- **Impact of overall incentive package:** Historically the electricity distribution sector has been exposed to a wider range of incentive mechanisms with more revenue exposed than other regulated network sectors. An important feature of the financeability analysis will be to undertake sensitivity analysis in relation to the range of possible outcomes from the proposed range of incentive mechanisms once these have been defined to determine any impact on risk profile either across sectors and/or across price control periods.

[53] Bristol Water Final Determination, Competition and Markets Authority, October 2015.

28. Financeability

FQ8. Do you agree with our proposal to align the RIIO-ED2 financeability approach with the approach we have taken for GD&T?

At a High-level the focus on the notional company to assess financeability is appropriate. Please see response to FQ10 for further detail.

FQ9. Are there any reasons why this approach should differ for RIIO-ED2?

At a High-level the focus on the notional company to assess financeability is appropriate. Please see response to FQ10 for further detail.

FQ10. Do you have a view, supported by evidence, regarding the appropriateness of different measures to address any financeability constraints?

At a high-level the focus on the notional company to assess financeability is appropriate. However, there are issues with Ofgem's proposed detailed financeability options which are detailed below:

- Changes to regulatory depreciation and capitalisation rates: A number of rating agencies have stated that they do not regard such changes as improving financeability[54;]
- Refinancing of expensive debt: The economic viability of repurchasing existing debt will be dependent on the buyback premium which in turn will depend on the coupon and the remaining term left. Uneconomic debt repurchase would destroy shareholder value and ultimately increase the cost capital; and
- Reduction in dividend: In the short term changes to dividend policy can be used to support financeability. However, as we have stated in previous responses a long term reduction in dividend is likely to increase investors risk perception of the industry and ultimately increase the cost of capital. In addition, while reducing the dividend will improve the debt/RAV credit metric it will only have a marginal effect on the Adjusted Interest Cover Metric with the latter typically being the limiting credit metric.

FQ11. Do you have any views on the proposed scenarios to be run for stress testing?

The types of stress test scenarios (interest rate, inflation, totex etc.) suggested are appropriate. However, for inflation we note that Ofgem do not regard +/ - 2% deviation in inflation from the baseline assumption as plausible. We note that the inflation level assumed in RIIO-ED1 price was 3.1%. However, inflation was 1.1% in 2015/16 and in all likelihood may also be 2% lower than the 3.1% assumption in 2020/21. We believe that a +/- 2% sensitivity on inflation is a plausible scenario. In addition, given the current economic outlook Ofgem should also give consideration to running a deflation scenario were inflation is negative as happened in 2009.

In addition, the mechanics of the proposed RoRE scenario may need to be reviewed and recalibrated. We believe that the current 300bps return adjustment mechanism cap needs to be rethought in light of the proposed incentive framework and consequently the RoRE scenario will need to align with this.

[54] Ofgem's Credit-Enhancing Mechanisms unlikely to Benefit Rating, Fitch Ratings, 28 February 2019.

29. Financial resilience

FQ12. Do you agree with our proposal to place additional requirements on licensees in RIIO-ED2 to provide Ofgem with a) published ratings reports, and b) a financial resilience report if their issuer credit rating falls below specified levels?

It would be helpful if Ofgem clarified its definition of published rating reports. Company specific press releases with regard to credit ratings are already public domain information. Rating agency company specific credit opinions are not public domain information are typically only available to subscribers of the rating agency's service. It would also be helpful to understand what conversations Ofgem has had with each of the rating agencies on this topic.

With respect to the financial resilience report companies already prepare on an annual basis a statement of financial adequacy for Ofgem. It would be helpful for Ofgem to set out how it sees this additional report interacting with the existing reporting framework including the Regulatory Financial Performance Report.

30. Corporation Tax

FQ13. Do you agree with our proposal to align the RIIO-ED2 tax approach with RIIO GD&T including; to pursue Option A; the approach to additional protections; the approach to capital allowances; and not to pursue the Fair Tax Mark certification as a requirement for RIIO-2?

We agree that Option A is the most sensible approach and that the introduction of the Fair Tax Mark is not necessary.

FQ14. Are there any reasons why this approach should differ for RIIO-ED2?

With respect to other protections our views are set out below:

- **Tax trigger and deadband:** The proposed approach for RIIO-GD and RIIO-T would also be appropriate for electricity distribution.
- **Submission of CT600 forms:** We have no objections to submitting our CT600 submissions to Ofgem subject to them not being externally published.
- **Tax reconciliation:** As is noted in the consultation there will be a one year timing difference between the tax reconciliation and the Regulatory Financial Performance report submission. We agree that further work is needed to define both the template and the guidance.
- **Board assurance statement:** We are unconvinced by Ofgem's statement that the DAG processes that support the submission of the Regulatory Financial Performance Report (RFPR) provide insufficient assurance on the tax reconciliation. Before instituting an additional reporting requirement Ofgem should provide specific evidence that the current mechanisms are not appropriate.
- **Tax review mechanism:** In principle we do not object to Ofgem introducing a tax review mechanism. However, as is noted in the consultation there is further work required to define the detailed mechanics, and in particular what would trigger a review.
- **Capital allowances:** We are concerned that the annual updating of capital allowances is introducing further additional complexity and revenue volatility into RIIO-ED2 without Ofgem identifying the benefit it will bring. The proposed price control is already becoming more complex with the indexation of both the cost of equity and real price effects and the introduction of a Returns Adjustment Mechanism.

31. Indexation of the RAV and allowed return

FQ15. Do you agree with our proposal to implement CPIH inflation?

We remain of the opinion that, from a customer perspective, CPIH may be a more legitimate inflation metric than RPI. However, as we highlighted in our response to the question on additional borrowing costs the switch will result in DNOs incurring additional financing costs which should be recognised and remunerated.

FQ16. Are there any reasons why this approach should differ for RIIO-ED2?

Please see our response to FQ15.

32. Regulatory depreciation

FQ17. Do you have any specific views or evidence relating to useful economic lives of ED network assets that may impact the assessment of appropriate depreciation rates?

The choice of regulatory asset lives is key input into ensuring that cost recovery is appropriately balanced between current and future customers. We believe that this is an area that should be kept under review as Business Plans are developed. The emergence of the DSO function coupled with an increasing need for more investment in shorter lived assets such as new computing capability may require the regulatory asset lives to be reviewed.

We note that at CMA review of RIIO-ED1 Ofgem indicated that this was an area that it may review. It would be helpful if Ofgem could share any work that it has had done in this area.

FQ18. During RIIO-ED1, the assumed asset life is being increased. Do you consider another change is required in RIIO-ED2 to reflect the expected economic asset life? If so, do you have supporting evidence and proposals, at this stage?

Please see our response to FQ17.

33. Capitalisation rate

FQ19. Do stakeholders support licensee specific rates for the ED sector?

In common with regulatory asset lives, the choice of regulatory capitalisation rate is a key factor in ensuring the correct allocation of costs between current and future customers. In common with regulatory depreciation this should be kept under review as RIIO-ED2 business plans develop.

FQ20. For one or more aggregations of totex, should we update rates ex-post to reflect reported outturn proportions for capex and opex?

We do not see the value in updating capitalisation rates to actual statutory rates ex-post. As noted above the choice of regulatory capitalisation is based on supporting intergenerational equity whereas the statutory capitalisation rate is a by-product of each company's interpretation of the relevant accounting standards. As the latter has no impact on customer charges we do not see a rationale for updating to ex-post statutory values.

34. Directly Remunerated Services

FQ21. Are there any reasons why the RIIO-ED2 approach to directly remunerated services should differ from RIIO-ED1?

We can currently see no reason why this should differ.

35. Disposal of assets

FQ22. Do you support our proposal to continue the RIIO-ED1 approach to disposal of assets for RIIO-ED2?

Yes, we support the continuation of the current RIIO-ED1 approach.

36. Dividend Policy

FQ23. Do you agree that additional reporting on executive pay/remuneration and dividend policies will help to improve the legitimacy and transparency of a company's performance under the price control?

In principle, we do not object to publishing more information on either executive remuneration or dividend policy. We do think it would be helpful if Ofgem worked with the regulated companies to develop further guidance in this area to ensure consistency of reporting. We believe the latter is essential if the reporting is to be both legitimate and transparent.

37. Return Adjustment Mechanism

FQ24. Do you agree with our proposal to introduce a symmetrical RAMs mechanism?

Consistent with our response to this question in the RIIO-ED2 Open Letter, we agree in principle that any RIIO-ED2 RAM mechanism should be symmetrical, however this response is predicated on changes being made elsewhere in the RIIO-ED2 price control arrangements, to ensure the initial cost allowances and incentives targets are calibrated appropriately, namely:

- Outperformance wedge – retention of any wedge impacts symmetry and as such the upside RAM limit should be amended to reflect this;
- Cost assessment (benchmarking) – benchmarking at the 85th percentile and applying the highest values from ranges provided for Ongoing Efficiency forecasts is not symmetrical for the initial setting of cost allowances, therefore the downside RAM is more likely to be triggered on a probabilistic basis;
- Cost assessment (interpolation) – basing the totex allowances 100 per cent on the Ofgem view of efficient costs, would appear, from the RIIO-GD2/T2 Draft Determinations, to result in lopsided initial cost allowances which again imply a bias towards the downside RAM limit being triggered; and
- Incentive targets – for the Interruptions Incentive Scheme Ofgem is proposing to overwrite the results of its own benchmarking methodology and provide tougher targets for frontier performers. This approach not only penalises those whose performance has helped reveal benchmarks that benefit all GB customers, but it places such DNOs in a harder "start to earn" position than if they had performed less well in RIIO-ED1.

FQ25. Do you agree with our proposal to introduce a single RAM threshold level of 300 basis points either side of the baseline allowed return on equity?

Whilst we agree that there should be a single RAM threshold and it should be calibrated in terms of RORE basis points, we disagree with the proposed level this is being placed at.

Whilst we note the rationale provided for why the 300 bps threshold was arrived at in RIIO-GD2/T2 with respect to the cost of debt and the total market return, we believe the threshold needs to reflect the broader suite of arrangements Ofgem is proposing for RIIO-ED2. Our modelling, set out in in Figure 7 below, indicates where the 300 bps RAM would apply across a range of totex and incentive scenarios. Cells in red denote totex/incentive performance combinations where the RAMs limit of ± 300bps is triggered. In paragraph 10.13 of Annex 3 to the SSMC Ofgem state "In any event, we do not believe any company will trigger RAMs without this being due to errors in the setting of the price control". We do not believe that achieving an average incentive outperformance level of 60% combined with totex outperformance of 4% would be characterised as "errors in the setting of the price control", as this would then appear to jeopardise the legitimacy of RIIO-ED2. Whilst fully accepting the need for some form of overall corrective mechanism, we are concerned that if not calibrated correctly, it could be triggered more frequently in RIIO-ED2 and in of itself attract criticism of the price control.

Figure 7: Total totex and incentive performance relative to baseline returns (results reported on RoRE basis points)

Cost performance (negative = underspend)	Incentive performance - Percentage of maximum available reward / penalty earned or incurred (negative = penalty)																				
	-100%	-90%	-80%	-70%	-60%	-50%	-40%	-30%	-20%	-10%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
10%	-593	-554	-515	-476	-438	-399	-360	-321	-282	-243	-204	-166	-128	-89	-51	-13	26	64	102	140	179
9%	-573	-534	-495	-456	-417	-378	-339	-301	-262	-223	-184	-146	-107	-69	-31	8	46	84	123	161	199
8%	-552	-513	-474	-436	-397	-358	-319	-280	-241	-202	-164	-125	-87	-49	-10	28	66	105	143	181	220
7%	-532	-493	-454	-415	-376	-337	-299	-260	-221	-182	-143	-105	-66	-28	10	49	87	125	163	202	240
6%	-511	-472	-434	-395	-356	-317	-278	-239	-200	-161	-123	-84	-46	-8	31	69	107	146	184	222	261
5%	-491	-452	-413	-374	-335	-297	-258	-219	-180	-141	-102	-64	-26	13	51	89	128	166	204	243	281
4%	-470	-432	-393	-354	-315	-276	-237	-198	-159	-121	-82	-43	-5	33	72	110	148	186	225	263	301
3%	-450	-411	-372	-333	-295	-256	-217	-178	-139	-100	-61	-23	15	54	92	130	169	207	245	284	322
2%	-430	-391	-352	-313	-274	-235	-196	-157	-119	-80	-41	-3	36	74	112	151	189	227	266	304	342
1%	-409	-370	-331	-293	-254	-215	-176	-137	-98	-59	-20	18	56	95	133	171	209	248	286	324	363
0%	-389	-350	-311	-272	-233	-194	-155	-117	-78	-39	0	38	77	115	153	192	230	268	307	345	383
-1%	-368	-329	-291	-252	-213	-174	-135	-96	-57	-18	20	59	97	135	174	212	250	289	327	365	404
-2%	-348	-309	-270	-231	-192	-153	-115	-76	-37	2	41	79	118	156	194	232	271	309	347	386	424
-3%	-327	-289	-250	-211	-172	-133	-94	-55	-16	22	61	100	138	176	215	253	291	330	368	406	444
-4%	-307	-268	-229	-190	-151	-113	-74	-35	4	43	82	120	158	197	235	273	312	350	388	427	465
-5%	-287	-248	-209	-170	-131	-92	-53	-14	24	63	102	141	179	217	255	294	332	370	409	447	485
-6%	-266	-227	-188	-149	-111	-72	-33	6	45	84	123	161	199	238	276	314	353	391	429	467	506
-7%	-246	-207	-168	-129	-90	-51	-12	26	65	104	143	181	220	258	296	335	373	411	450	488	526
-8%	-225	-186	-147	-109	-70	-31	8	47	86	125	164	202	240	278	317	355	393	432	470	508	547
-9%	-205	-166	-127	-88	-49	-10	28	67	106	145	184	222	261	299	337	376	414	452	490	529	567
-10%	-184	-145	-107	-68	-29	10	49	88	127	166	204	243	281	319	358	396	434	473	511	549	588

FQ26. Do you have any other comments on our proposals for RAMs in RIIO-ED2?

We note your proposal in paragraph 10.19 of Annex 3 to the SSMC to apply any RAMs adjustment as part of the RIIO-ED2 closeout and reflect in company revenues in RIIO-ED3. We disagree with this approach, and instead believe it would be in current and future customers interests, as well as licensees, for an annual, “current outturn” true-up to be built into the PCFM. We believe this will reduce the potential bill impact should a full RAM reconciliation exercise only be conducted at RIIO-ED2 closeout and then applied to RIIO-ED3 revenues.

Our experience from the most recently concluded price control closeout process, was the DPCR5 closeout, which was simpler than what is likely to be required for the RIIO-ED2 closeout, and this still took two years to conclude, with revenues then being adjusted over the remaining four years of RIIO-ED1. Even if the more complex RIIO-ED2 closeout process could be concluded in a similar timeframe, this would then only provide three years for the adjustments to revenue to be applied, ultimately increasing bill shocks to customers and revenue volatility to licensees and suppliers.