



RIIO-ED3

Framework Consultation Response Appendix 1

15 January 2025

Index

Drivers for change	6
Question 1. Do you agree with our characterisation of the wider context for ED3? Are there any other areas of context that you consider material for ED3?	6
ED3 objective and consumer outcomes	6
Question 2. What are your views on our overarching objective and proposed consumer outcomes?	6
Regulatory framework	7
Question 3. Do you agree that the network investment elements of the framework should be more input based?	7
Question 4. Do you agree that we should consider introducing additional controls around network investments and what features should these controls contain?	8
Question 5. Do you agree that the incentives on DNOs will need to adapt from RIIO-ED2 and if so, how?	9
Question 6. Do you agree that there is still a role for re-openers in ED3, particularly given the timing of the future full RESP output and how should these be triggered?	10
Question 7. Using RIIO-ED2 as the counterfactual, what alternative regulatory models or characteristics are needed in ED3 to ensure the DNOs deliver the above consumer outcomes? What are the trade-offs we should consider?	11
Question 8. Do you agree that the regulatory framework for ED3 should have features of the Plan and Deliver model for network investment and Incentive Regulation model for other elements?	11
Question 9. Do you think that there is a greater role for elements of ex post regulation or of cost pass through in ED3, either specifically in assessing cost changes resulting from changes to investment requirements during the period, or more broadly to reflect the changing context?	13
Networks for net zero	14
Question 10. What is the potential availability of network flex across GB for DNOs in the short term and on the journey to net zero during ED3?	14
Question 11. To what extent are global supply chain and workforce pressures contributing to longer lead times for delivery network reinforcement?	15
Question 12. Do you agree that the risk and downside for consumers of network underinvestment in network reinforcement would be greater than the downside of overinvestment?	16
Question 13. What are the benefits and risks to deliverability if network reinforcement is deferred to future periods?	18
Question 14. What do you see as the role of distributed flexibility, both in the short and longer term, to manage distribution network constraints?	19
Question 15. How do we ensure that network flexibility is used only when it is in consumers' long-term interests in ED3?	21
Question 16. How are unexpected constraints dealt with currently? How quickly can these be eased, and what is the impact of these unexpected constraints (e.g. on LCT uptake)?	22
Question 17. Do you agree that the tRESP output outlined for early 2026 will help create a level playing field for DNOs' business planning and support the ED3 objective and consumer outcomes?	23

Question 18. Can anticipatory network reinforcement be used to smooth the long-term build profile to avoid creating pinch points for the supply chain and workforce? What are the risks and trade-offs?	24
Question 19. Do you agree that investment optioneering should aim to reduce the lifetime costs by sizing elements of works for long-term need, including considering the impact of thermal losses?	26
Question 20. Is a 5-year price control (2028-33) the right duration to achieve the objective of securing timely network capacity for the net zero transition at least cost to consumers over the long run?	26
Question 21. To what extent should the price control be more directive on specific anticipatory and strategic investments to achieve the 'networks for net zero' consumer outcome?	26
Question 22. Do you agree with our characterisation of strategic and anticipatory investment and our expectation that these activities would have different regulatory drivers and controls?	27
Question 23. Should the price control provide more guidance or guardrails around the use of particular network solutions to achieve the 'networks for net zero' consumer outcome?	27
Question 24. Should we consider how we might bring all network capex investment together within the framework, irrespective of driver (e.g. load, asset health, resilience), to ensure a common approach to future proofing and delivery?	28
Responsible Business	28
Question 25. How can we better strengthen accountability for consumer outcomes?	28
Question 26. What are your views on ED company reporting and the overall transparency of performance and compliance?	29
Question 27. Do you consider that ISGs alone are sufficient to ensure high quality and effective consumer and stakeholder engagement throughout the ED3 price control? What alternative or complementary approaches should we consider?	31
Question 28. Do you agree that Ofgem should adopt research approaches, such as deliberative techniques to ensure that the consumer voice is heard and considered throughout the ED3 and company Business Plan process?	31
Question 29. How should our approach to enhanced stakeholder engagement be adapted to better include the perspectives of all vulnerable customers, including those that are seldom heard, digitally disengaged/excluded and those that are worst served?	32
Question 30. What alternative or additional approaches might we use to ensure that the consumer voice remains central to our policy setting process?	32
Question 31. Has the BMCS incentive served its purpose in driving performance improvements and how can we adapt the metrics to better incentivise performance across a wider range of interactions between DNOs and their customers, particularly relating to connections?	33
Question 32. How should the CVI be adapted for ED3, and should we consider greater alignment with the GD sector?	33
Question 33. Should DNOs have a role in delivering energy efficiency measures to homes and businesses? What might the scope of these services be and how should they be funded?	35
Question 34. How can we drive further service improvements under the TTC incentive?	35
Question 35. Should the TTC also apply to domestic connection upgrades i.e. fuse/cutout/service cable upgrades, including unlooping?	36
Question 36. What is the best approach towards incentivising services to major connections customers and how should the MCI be adapted for ED3?	37

Question 37. How should the ED3 framework adapt to ensure that customers connecting to the distribution network are provided with the service that they need from the DNOs?	37
Question 38. In the context of greater electrification, is our current approach towards regulating reliability appropriate for ED3?	39
Question 39. What role should bespoke outputs and CVPs have in ED3?	40
Question 40. How can we optimise late and early competition models for application in electricity distribution?	40
Question 41. How should our approach to cost assessment evolve, to enable us to better manage increasingly pronounced trade-offs between consumer protection, efficiency and investment in the distribution network?	41
Question 42. How should our guidance for cost benefit analysis evolve to better enable optioneering between different interventions, taking relevant long-term risks and benefits into consideration?	43
Question 43. Do you agree that the current Real Price Effect (RPE) methodology should form the basis for adjusting allowances in ED3?	44
Question 44. Do you agree that the current approach to setting the ongoing efficiency challenge is a suitable starting point for ED3?	44
Question 45. Do you see any reason why we should not implement the proposed changes to the calculation allowed returns, consideration of investability and assessment of financeability that we set out in RIIO-3 Sector Specific Methodology Decision – Finance Annex for ET, GT and GD?	45
Question 46. Do you see any reason why we should not implement the proposed updates to financial resilience requirements that we set out in RIIO-3 Sector Specific Methodology Decision – Finance Annex for ET, GT and GD?	46
Question 47. What are the key factors (including benefits and costs to consumers) that Ofgem should take into consideration when conducting its review of the appropriate approach to regulatory depreciation in ED3 and beyond?	48
Smarter Networks	49
Question 48. How should the price control encourage ongoing development of the DSO role and activities to optimise whole system benefits for existing and future consumers?	49
Question 49. What should the role of the DSOs be in identifying and delivering whole system benefits?	49
Question 50. Our historic approach to publishing and sharing datasets has been stakeholder-led and focused on establishing good digital foundations in the DNOs. With the rapid pace needed for enhanced data and digitalisation, should we instead be considering incentives around strategic priorities, such as network planning, flexibility, and connections?	50
Question 51. How can we enable greater development of internal digital expertise in its licensees?	51
Question 52. How should network companies use AI to improve network insight and decision-making (both operating expenditure (opex) and capital expenditure (capex)) and how should we be encouraging this through the ED3 framework?	52
Question 53. Our aim is for the ED3 framework to be structured to deliver high impact, transformative innovation – do you think that further changes, alongside those proposed for the other sectors in our RIIO-3 SSMD, are required to deliver this?	53
Question 54. Are there any factors particular to DNOs that facilitate or challenge deployment of innovation on their own and across networks?	54

Resilient and sustainable networks	54
Question 55. Do you agree that we should retain the Network Asset Risk Metric (NARM)? How should it further evolve in ED3?	54
Question 56. Do you agree that we should consider a more integrated approach to managing asset health, together with load-driven expenditure, given the need to future proof for resilience (climate, cyber and physical security) and future demand? What might the risks and benefits of this approach be?	55
Question 57. In the context of making anticipatory investment decisions, what do network companies and other stakeholders need to enable the planning and delivery of cost-effective network resilience measures against our changing climate? What risks and opportunities do you see linked to an input-based approach to these investment plans?	57
Question 58. How should we monitor progress on the delivery of climate change resilience? Do you have any specific learnings which can help shape this?	58
Question 59. Do you have any comments on the suitability of current incentives to ensure that consumers continue to receive a reliable service in the face of climate hazards?	59
Question 60. Do stakeholders agree with retaining and strengthening the main components of the environmental framework from RIIO-ED2?	60
Question 61. Do stakeholders agree with building on the approach taken to cyber resilience in RIIO-3 for ED3?	61
Question 62. What specific issues are network companies facing in relation to the skills and capacity of their workforce and what measures should we take through the regulatory framework to mitigate these issues?	62
Question 63. What specific issues are supply chains facing and what measures should we take through the regulatory framework to mitigate these issues?	63
Question 64. Given our comments in Chapter 6 around taking a more proactive approach, are there any specific features of a more anticipatory or strategic investment approach that might create risks or opportunities for supply chain and workforce constraints?	64
Question 65. What would the benefits be of a geographical approach to delivering new and upgraded assets in terms of supply chain and workforce constraints?	65

Drivers for change

Question 1. Do you agree with our characterisation of the wider context for ED3? Are there any other areas of context that you consider material for ED3?

We strongly agree with Ofgem’s characterisation of the wider ED3 context and specific statement that a significant increase in network capacity is required. As most of our economy electrifies to reach climate objectives, it is essential that electricity network capacity is ready before it is needed. The need to act early is strengthened by the existing supply chain and workforce challenges. There is no doubt electricity is the key energy vector to facilitate net zero, we understand and take our role extremely seriously. ED3 is the key price control to shift the dial and lay strong proactive foundations to be able to deliver net zero in subsequent price controls.

ED3 objective and consumer outcomes

Question 2. What are your views on our overarching objective and proposed consumer outcomes?

We believe investment in electricity networks provides a unique opportunity to drive both strong economic growth and deliver our net zero aims and are strongly supportive of Ofgem’s growth and net zero duties and of the proactive approach to considering these when defining the approach to ED3. With this context, we have some additional suggestions on how these duties could be further reflected within the ED3 overarching objective and framework.

- Using the terminology from the Government’s recent consultation “Invest 2035: the UK’s modern industrial strategy”¹, we believe electricity networks to be a growth driving foundational sector which is facilitating economic growth throughout the country. We suggest that it would be aligned with Ofgem’s new growth duty if the ED3 framework adopts the same powerful terminology when referencing networks as this will help to communicate the significance of networks’ role to stakeholders.
- The consultation proposes the following as the overarching ED3 objective: *“the price control should ensure that current and future consumers’ interests are met by electricity distribution networks providing the necessary network capacity, to enable decarbonisation goals, at least cost, based on whole system value”*.

We do not believe that the inclusion of “at least cost” terminology accurately reflects the scale of the increased investment needed in electricity distribution networks to enable the required network capacity ahead of need, which we need to achieve our country’s decarbonisation goals. The Government set out in its strategy that an estimated “additional £50 to £60 billion of capital investment will be required each year through the late 2020s and 2030s to achieve our net zero ambitions– it will be money well spent, as the ‘size of the prize’ is significant.” An International Monetary Fund (IMF) study suggested that growth multipliers associated with clean energy investment (1.1 to 1.5) are larger than those

¹ [Invest 2035: the UK’s modern industrial strategy - GOV.UK](#)

associated with fossil fuels. We suggest Ofgem replaces “at least cost” with “efficiently”. This would also better align the GEMA’s principal objective, and general duties as set out in section 3A of the Electricity Act 1989, and section 3A (5) (a) in particular.²

- We also suggest that Ofgem adds “and economic growth objectives” after “to enable decarbonization goals”, to more accurately reflect Ofgem’s growth duty.

We generally agree with the four consumer outcomes, but linked to the comments above, for the **Networks for net zero** outcome we suggest changing the “at least cost” terminology to “efficiently”.

Regulatory framework

Question 3. Do you agree that the network investment elements of the framework should be more input based?

We strongly support RIIO with its focus on incentivising output delivery. This has been successful in driving a step change in improvements across key areas that matter to customers including customer service standards and network interruptions. The model has been successful in encouraging network companies to do what it was designed for including:³

- seeking to better understand the new and changing needs of existing and future consumers,
- investing in new capital assets and new operating solutions,
- undertaking more innovation, both technological and commercial,
- looking for ways of delivering economic and efficient network services at long-term value for money,
- considering alternative delivery options given uncertainty about how best to deliver, and
- developing new commercial relationships with users of the network and end consumers, to enable them to meet the challenges together.

These drivers are as relevant going forward as they were at the time of RIIO’s introduction. With this in mind, we feel an evolution of the RIIO framework has the potential to meet the challenges of delivering network capacity at pace without compromising what it is designed to achieve (and what it has in fact achieved to date) as a package.

Whilst we continue to believe an output-based framework should remain at the core of the ED3 regulatory framework, we also understand that the introduction of the RESP, CSNP and SSEP bring with it a shift towards a more strategically planned energy system, and we understand that the ED3 framework needs to operate within that context. If this new strategically planned energy system translates to a more input based, prescriptive approach for certain areas of DNOs’ plans such as load related expenditure, then it is vital that the scope and process/timescales relating to any inputs that DNOs are expected to utilise in the production of their business plan

² [Electricity Act 1989](#)

³ [Regulating energy networks for the future: RPI-X@20 decision document | Ofgem](#)

(and also within the price control period), are clearly set out early in the plan development process. In addition, the content of the inputs that DNOs are expected to include or use in their business plan development should not be a surprise to DNOs and DNOs should be involved in an iterative process to develop these before they are finalised.

We set out above that clarity on inputs is key, however, it is also essential that DNOs are provided with absolute clarity on not just the content and process surrounding the inputs, but also on the incentive and control framework within which DNOs must operate. This clarity needs to be given either within or before the SSMD publication. It is a combination of all of these factors as a whole which will shape the price control package which our shareholders need to be able to support before agreeing to invest for net zero.

Question 4. Do you agree that we should consider introducing additional controls around network investments and what features should these controls contain?

Enabling proactive investment to create capacity needed both within and in future price controls has been set out as a defining characteristic of the new ED3 framework and we appreciate Ofgem will want to consider additional controls to ensure that this investment is delivered.

Against this context, we agree that the ED3 framework should ensure that DNOs are held to account to deliver network load investment that is identified as strategic. As part of an iterative process between DNOs and the NESO, we expect those types of investments to be part of the tRESP/RESP and used by the DNOs as an input to DNO network plans.

For those specific, and highly limited in number, strategic investments, we understand the desire to ensure that outputs are being delivered based on the agreed inputs. We can see that the use of PCDs would allow for greater control around delivery. However, the detail of these PCDs would need to be carefully considered to ensure that: (i) they do not penalise DNOs for inability to deliver amidst uncertain and challenging circumstances, like supply chain constraints; and (ii) they do not prevent DNOs from striving to deliver the outputs in as efficient manner as possible, i.e. where outputs have been delivered and have been delivered efficiently, then customers and DNOs should benefit from this via application of the TIM.

On the other hand, PCDs should not be applied to primary reinforcement investment that is not identified as a strategic investment. Instead, Ofgem should continue to monitor, as they do now, delivery against the load programme throughout the price control with closeout at the end of the ED3 period.

For the high volume of anticipatory and JIT investments related to secondary reinforcement, we agree with Ofgem that it would not be practical to assign specific PCDs. Instead, for these, Ofgem is considering an aggregate deliver metric to ensure that delivery is consistent with the agreed ex ante plans and allowances, which will have been based on the associated inputs (the inputs in this context will be input assumptions, i.e. the RESP pathways and assumptions, and any Ofgem guidance). The suggestion is that aggregate delivery metrics could track delivery against the expected benefits from an investment plan as well as the activities and that the current secondary reinforcement volume driver could be used or adapted to do this (with potential parameters including net capacity additions to meet certain future need, the volume of firm connections enabled, and the mix of interventions deployed).

We understand that the NESO will have reviewed both our DFES and also our load business plans to give a view on whether the inputs have been applied appropriately. These reviews are essentially additional controls within this new framework. These should give Ofgem assurance that our investment plans have been designed to the parameters provided under this new strategically planned energy system.

Question 5. Do you agree that the incentives on DNOs will need to adapt from RIIO-ED2 and if so, how?

As part of the policy development and consultation stage of any price control, it is important to consider whether the incentives from the previous control are still fit for purpose. In ED2, the incentives can be split into the upfront truth telling Business Plan incentive, incentives on output delivery and the totex incentive (or Totex Incentive Mechanism (TIM), which incentivises cost efficiency and innovation); we consider each of these below.

Although the consultation does not go into detail on the business Plan Incentive (BPI) specifically, it does include a question on one element of this (Consumer Value Propositions, CVPs), see our answer to question 39. It also discusses the Totex Incentive Mechanism (TIM), which is intrinsically linked to the content of business plans and is discussed further below. As a general point, we believe that an upfront truth telling incentive is useful in overcoming potential information asymmetry and encourages DNOs to submit high quality plans. These needs still exist in ED3, so we believe there is still a place for a BPI type of mechanism. However, the format of the BPI in ED2 had challenges and we know Ofgem has proposed adjustments to the BPI as part of the RIIO-3 SSMD. We look forward to reviewing the detailed proposals on a revised BPI for ED3 as they emerge through Working Group discussions and ultimately within the SSMC.

In relation to outputs, we do not expect the output areas that are incentivised in ED2, to be any less important to customers during ED3. These for example include outputs related to core consumer outcomes in the areas of reliability, customer service and connections. In fact, these areas will only grow in importance. On the other hand, if consumer research identified new priority areas, then it would be appropriate to consider whether additional Output Delivery Incentives (ODIs) should be created to improve output delivery and performance. For the existing ODIs, we expect the Working Groups to discuss the detailed parameters and targets to establish if any of these aspects should be re-calibrated for ED3. We have included some points on specific ODIs in response to questions in section 7 of the framework consultation.

The consultation text surrounding question 5 suggests that Ofgem is primarily asking this question in relation to the TIM cost efficiency/innovation incentive. We firmly believe that the TIM is a cornerstone of the RIIO framework. Adopting a totex approach, encourages the identification of synergies across the entirety of a DNO's investment plan, allows DNOs to fully utilise their knowledge and experience of their networks, and creates a culture of continuous improvement, in the knowledge that both customers and shareholders will benefit from the identification of efficiencies.

Ofgem has said it is concerned that the TIM may incentivise companies to underinvest in the network. In our view, we believe that Ofgem can address this concern without complete removal of the totex and TIM approach and believe that a suite of alternative, targeted tools can be used

to mitigate against Ofgem's concerns in specific areas, without changing the foundations of the price control. For example, as outlined in our response to question 4, for secondary reinforcement we agree with Ofgem that an aggregate monitoring metric could be explored. Whilst high value strategic investments on the primary network, could have allowances ringfenced into PCDs to monitor specific delivery, but retain some of the incentive properties of the TIM by applying the TIM within the PCD at a more granular level. Ultimately, if Ofgem were to decide that the TIM in its current form is not appropriate for ED3, then it is important that an alternative cost efficiency incentive is developed to ensure the drive to be efficient remains.

Question 6. Do you agree that there is still a role for re-openers in ED3, particularly given the timing of the future full RESP output and how should these be triggered?

We do believe there is a role for re-openers in ED3. However, Ofgem should not automatically default to the use of re-openers as the only mechanism for managing uncertainty and should more thoroughly assess whether other uncertainty mechanisms (including UIOLI allowances) may be a more suitable and less burdensome mechanism in certain circumstances.

Notwithstanding the point above, the reopener process itself needs to be improved. Ofgem should seek to identify ways to review the reopener justification process, with the aim of improving flexibility, reducing the prescriptiveness of reopener topics, alleviating the resource burden on both network operators and Ofgem, and expediting approval timelines. The recent Storm Arwen reopener has been a clear example of where timelines have been long (almost one year from proposal submission to Ofgem decisions) and the resource investment high, with Ofgem rejecting a large amount of proposals submitted in good faith.

We firmly believe a more flexible application process is needed and there is merit in considering a 're-opener light' process for certain proposals. For example, the consultation arrangements should be streamlined for investments where the need case is clear (for example, a new legislative requirement), and proposals below a certain materiality threshold should not have to be subject to the same rigour as those of higher value.

It is not realistic to maintain the large range of re-openers from ED2 and apply the current cumbersome reopener process to all of these – this is not realistic for companies, nor for Ofgem with its scarce resources.

On the RESP reopener in particular, Ofgem should carefully consider how this process is going to work in practice. This process cannot be used to completely re-write our load plan mid-way through the price control as there will have been a robust governance process around ensuring that DNO shareholders have signed off on the price control package, and significant modifications to this would challenge that process. In addition, if the ED3 framework is being designed to ensure that DNOs commit to proactive network investment to ensure there is sufficient network capacity to meet future net zero needs, then they need confidence that their expenditure will be funded. A reopener process which creates uncertainty around regulatory approval or cost allowances would make it difficult for DNOs to make significant contractual and resource commitments, which could jeopardise investment plans.

Question 7. Using RIIO-ED2 as the counterfactual, what alternative regulatory models or characteristics are needed in ED3 to ensure the DNOs deliver the above consumer outcomes? What are the trade-offs we should consider?

As set out in our response to previous questions, Ofgem should look to maintain as much of the incentive and outputs-based model which has made the RIIO framework world leading. Ofgem is right to highlight the shift in risk from overinvestment to underinvestment. We have argued for some time that early investment in capacity in our network is needed to ensure sufficient capacity is available when needed.

We do not believe Ofgem should go back and revisit the FSNR, as is implied in paragraph 5.19, but focus its efforts on bringing clarity to the sector on how elements of ‘input’/‘Plan and Deliver’ would work within a predominantly incentive and output based regulatory model. Now is not the time to fundamentally revisit theoretical models and reconsider the undeniably successful RIIO model. We must move at pace to create clarity on the ED3 framework at SSMC/D and particularly set out in more detail how Ofgem foresees an input-based approach working in some areas.

Question 8. Do you agree that the regulatory framework for ED3 should have features of the Plan and Deliver model for network investment and Incentive Regulation model for other elements?

Using the regulatory dimensions set out in the consultation, we understand that compared to incentive-based regulation and the ED2 counterfactual, a move to Plan and Deliver could introduce some of the following features:

- More inputs focussed with prescription about solutions, deliverables or assumptions.
- less use of output-based regulation, with fewer incentives driving behaviours on clear objectives and targets.
- less fungibility of allowances between cost categories; and
- less ex-ante funding with more allowances set in period through uncertainty mechanisms and/or following ex post evaluation.

As set out in our response to question 3 we strongly support the RIIO framework and incentive regulation continuing into ED3. We believe that if the RIIO framework was replaced with all of the features above it would be a retrograde step and would remove the considerable benefits that has resulted in RIIO being recognised as a world leading framework.

However, we also understand that the introduction of the RESP, CSNP and SSEP bring with it a shift towards a more strategically planned energy system and that the ED3 framework needs to operate within that context. We therefore take each of the above features in turn and give our views on whether we believe they could have a place in the ED3 framework:

- (i) **Inputs:** we can understand how a more strategically planned system would result in more inputs for the DNOs. From the consultation content and Working Group discussions, we understand that two different types of input are being proposed:

- a. Following recommendations by and discussions with DNOs, we believe that certain strategic investment input recommendations could be made within the tRESP/RESP e.g. a strategic high value primary substation. The key point here is that the network planning responsibilities sit with the DNO, so any such recommendations could only be included if they have endorsement upfront from the DNO.
 - b. Input assumptions and guidance around aspects of the load plans. Specifically, we understand these to be: tRESP/RESP pathways of volumes of LCTs; and tRESP assumptions for DNOs to consider in the translation of the DFES content into the development of their network plans, potentially alongside Ofgem guidance for DNOs to also consider in the development of their network plans. We believe that DNOs need to be heavily involved in the development of any such assumptions, or there is a risk that their application could have unintended consequences when applied to real planning decisions.
- (ii) **Outputs:** we do not believe that the introduction of the targeted inputs above, would necessitate the removal of the core ED2 outputs and output delivery incentives. As outlined in our response to question 5, we do not expect the output areas currently incentivised in ED2, to be any less important to customers during ED3 and in fact as the reliance on our network grows, then areas like reliability, customer service and connections will only grow in importance.
- (iii) **Fungibility of allowances:** As outlined in our response to question 5, we firmly believe that totex and the Totex Incentive Mechanism (TIM) are cornerstones of the RIIO framework which encourage the identification of synergies across the entirety of a DNO's investment plan, in the knowledge that both customers and shareholders will benefit from the identification of efficiencies. We believe that any concerns that Ofgem has around potential underinvestment in the network can be addressed via a suite of alternative, targeted tools without complete removal of the totex and TIM approach. For example, as outlined in our response to question 4, for secondary reinforcement we agree with Ofgem that an aggregate monitoring metric could be explored. Whilst high value strategic investments on the primary network, could have allowances ringfenced into PCDs to monitor specific delivery, but retain some of the incentive properties of the TIM by applying the TIM within the PCD at a more granular level.
- (iv) **Ex ante allowances:** Sufficient allowances must be awarded on an ex-ante basis to ensure we can raise the required funds for investment in our future ED3 business plan. Within ED2, our shareholders have accepted the overall package, including the use of specific uncertainty mechanisms like reopeners and volume drivers. We expect these mechanisms to be part of the ED3 framework, but they cannot be adopted instead of sufficient ex ante allowances and instead should be complementary. The more uncertainty mechanisms are used, the higher the risk that finance costs will be more variable and potentially higher, risking our shared objective to ensure network investment is as efficient as possible.

Question 9. Do you think that there is a greater role for elements of ex post regulation or of cost pass through in ED3, either specifically in assessing cost changes resulting from changes to investment requirements during the period, or more broadly to reflect the changing context?

RIIO has delivered real benefits for consumers and network customers, and we continue to believe that should be the starting point for any changes. Radical change would threaten investor confidence at a time when the need for significant investment is critical to enable net zero for our communities. Within this context, we support the aim of simplification of the regulatory framework. It is sensible to look at the lessons learned from RIIO-1 and RIIO-2 to reduce unnecessary complexity, and to make the regulatory effort and resource burden more proportionate for Ofgem and industry, as well as amending or removing elements that do not deliver what they need to.

The gap between what is needed and what is available is widening because there are long lead times for transmission and distribution equipment and utilities (globally) are countering the problem by placing orders sooner, looking for new and more secure suppliers, and aggregating buying power. Network development programmes in the UK risk being left behind if potential upheaval to future regulatory arrangements prevents network companies in the UK from taking similar measures or undermines supply chain confidence in committing to UK infrastructure needs. Indeed, the Global Infrastructure Investor Association (GIIA) Infrastructure Pulse survey which gathers views directly from investors who manage a total of 1 trillion dollars in infrastructure assets around the world, states that 'In the UK in particular, respondents continue to cite an 'unattractive regulatory regime' and 'political instability' as considerably bigger brakes on investment compared to the rest of Europe and Americas.' We certainly do not want to see this position worsen.

We are in an unprecedented environment where SPEN's shareholders are expected to make a 3-to-5-fold run rate increase of annual investment during RIIO-3 when compared to current expenditure levels; we have not seen this level of investment since privatisation. It is therefore crucial that the current risk environment is assessed fully when negotiating revised rates of return or risk levels. The regulatory framework can be adapted to support some of these issues by allowing a significant proportion of ex-ante funding to be granted for our future projects to allow us to progress at pace and without undue risk. However, we believe that any potential expansion of the use of ex post / cost-plus regime should not be ruled out but requires further assessment and detail from Ofgem. Whilst we can see that theoretically this approach could allow investment delivery at pace where there is a clear needs case, but due a significant level of uncertainty in forecast costs e.g. due to an imbalance in power between network operators and the supply chain, we have concerns with the risk of being faced with 'hindsight regulation' and a level of ex-post clawback that is unanticipated.

Overall, we suggested that regulatory changes to price control mechanisms (i.e. departure from RIIO) would need to be assessed via how they would impact the following areas/aspects:

- Regulatory resource burden.
- speed of decision making.
- speed of investment.

- Improve delivery challenges (i.e. supply chain issues/consenting delays)
- sector attractiveness to investors.

It is becoming increasingly difficult to utilise the traditional RIIO cost assessment approach and tools. The price control, in respect of load and non-load investment, can be viewed as a fixed price contract for a range of projects with differing levels of maturity (i.e. some at concept approval through to those in construction) based on a 'snapshot' of the future. The adjustments are predominantly geared towards additional projects. This creates unique challenges under the current RIIO framework as most of the investment is based on engineering cost estimates (at settlement) rather than competitively awarded contracts. The future price control framework should more clearly recognise what areas of costs can be controlled and what cannot. For these reasons, we believe that any potential expansion of the use of ex post / cost-plus regime should not be ruled out but requires further assessment and detail from Ofgem.

Networks for net zero

Question 10. What is the potential availability of network flex across GB for DNOs in the short term and on the journey to net zero during ED3?

In the NESO's CP2030 supporting paper - Annex 1: Electricity demand and supply they highlighted that 2.5GW of Demand Side Flexibility currently exists, alongside an additional 4GW of storage heaters.⁴ The NESO states that their CP2030 pathways require this level of flexibility to grow by 4-5 times by 2030.

This challenge can be broken down into two separate challenges, firstly the actual growth of connected Demand Side Flexibility and secondly a step change in how we, as an industry engage with domestic customers that could provide flexibility. On the first challenge, DNOs can support the shortfall gap by ensuring that network capacity is available to allow sources of Demand Side Flexibility to connect, and an ED3 framework that enables anticipatory investment to materialise can support this. This anticipatory investment would also support the NESO's ability to access Demand Side Flexibility by ensuring sufficient network infrastructure is in place to minimise any restrictions of access to Demand Side Flexibility.

On the second challenge, in relation to the engagement of domestic customers that could provide flexibility, we would expect to see improvements here through the implementation of Elexon as the UK Market Facilitator. In addition, by accelerating the ambitions of Ofgem's proposed Flexibility Digital Infrastructure we can maximise the ability for flexibility providers to support DSO and NESO system requirements without negatively impacting existing customers by e.g. avoiding network overloads or loss of supply due to over provision of demand turn up services in a localised geographical/network area.

The NESO also states that they expect Demand Turn up capabilities to increase to 14.3GW by 2030. We have trialled and demonstrated the potential for Demand Turn up services in our own Demand Shift Trial, however we also recognised that as the scale of Demand turn up increases

⁴ [Clean Power 2030 - Annex 1: Electricity Demand and Supply Analysis](#)

there will be limits on the Distribution Network.⁵ It is essential that as the growth of Demand Side Flexibility increases and the NESO becomes increasingly reliant on providers connected to the Distribution network, that we need to evolve the level of coordination between DSOs and the NESO. Whilst the ENA's Open Networks project and network operators have advanced the topic of Primacy and the stackability of services, we now need to implement a step change in how Primacy and stackability can be systematised and digitised.

Question 11. To what extent are global supply chain and workforce pressures contributing to longer lead times for delivery network reinforcement?

Global supply chain shortages and workforce pressures are contributing to longer lead times. We have seen manufacturer lead times for key equipment increase [REDACTED] in the last five years.

In response, we have increased our pool of suppliers and are having to order equipment earlier, sometimes before the need is realised. These actions are in consumer's interests in a world of increasing lead times and decarbonisation growth as they help avoid capacity shortfalls, but they come with costs and risks. The ED3 price control mechanism should reflect these.

Drivers of supply chain and workforce pressure

Longer lead times at distribution are primarily due to two factors:

1. **Increased demand for both network assets and workforce pressures** both in GB and globally. For example, Transmission operators settle their price control two years earlier than DNOs which increases the pressures on DNO supply chains and delivery resource, particularly for 132kV infrastructure.
2. **More localised workforce** as workers are less willing to travel. For example, historically teams from Ireland helped during periods of high delivery, but this is no longer feasible due to the level of activity in Ireland. Workers from further afield need to be qualified to GB standards, which adds to the challenge.

The shortages create two main issues: longer lead times and increasing delivery costs. For manufacturer lead times, some of the changes we have seen in the last five years include:

- [REDACTED]

These are just the timescales to receive the assets, we then need to install them. Demand for workforce and greater localisation mean we are seeing an increase in contractor labour rates and longer lead-times until they are available.

How we are responding and how this affects ED3

⁵ [Creating new opportunities through UK's first Flexibility Demand Shift trial - SP Energy Networks](#)

In response, we have expanded our supply base. Additionally, orders are increasingly placed earlier, making them slightly more predictive rather than reactive. For example, a 132kV transformer required in 2027 may be ordered now, even before the specific use-case is finalised.

These measures are in consumers' interests as they help avoid capacity shortfalls, which (as discussed in our response to question 12) can negatively impact safety, reliability, decarbonisation efforts, network costs, and economic growth.

ED3

The ED3 framework should therefore: reflect that asset and labour costs are increasing, reflect that manufacturer commercial terms are changing (buyers now pay more upfront instead of on delivery), consider allowances for DNOs to hold more stock (especially for high volumes standardised assets such as HV/LV transformers), and allow regulatory flexibility for earlier procurement and stock holding (especially if a more rigid Plan & Deliver regulatory model is developed).

Question 12. Do you agree that the risk and downside for consumers of network underinvestment in network reinforcement would be greater than the downside of overinvestment?

Yes, we agree. We consider that the risks and downside of underinvestment are significantly greater than the risk of overinvestment. Underinvestment (both in terms of timing and capacity) would be a great disservice to our customers and society. This is because:

- **The likelihood of overinvestment is low** because all FES scenarios show significantly increasing demand and generation – it is a question of *when* not *if*. The impact of overinvestment is low as earlier investment can help coordinate delivery and reduce losses.
- **In contrast, the impacts of underinvestment are high:** safety and reliability impacts, barriers to societal decarbonisation and connections for CP2030, higher network and system balancing costs, deliverability inefficiencies, and a barrier to economic growth.

The risks and downside of underinvestment

Underinvestment risks insufficient network capacity for customers. This will have seven key impacts:

1. **Decarbonisation and LCT uptake would slow.** Customers would be less likely to transition to EVs and heat pumps if they cannot use these immediately and at full capacity. This is particularly important for heat pumps as customers infrequently change heating system. Similarly, industrial customers are unlikely to wait for network capacity when deciding whether to decarbonise their processes. We must make it easy for customers to transition and decarbonise – having the network capacity ready is part of this.
2. **Network reliability would suffer.** Where customers continue to transition to low carbon technologies without there being sufficient capacity, it risks overloading the network. Electricity reliability would suffer at a time when GB needs to convince consumers to transition more of their energy consumption to electricity.

3. **CP2030 would be at risk.** For larger capacity customers such as renewable generation, connection delays are a barrier to achieving CP2030. We need zero carbon generation, and tools to help balance the system, connected to the system quickly to achieve CP2030.
4. **Long term network costs and disruption would increase.** Where we underinvest on capacity, there is a greater chance that we will need to revisit before end-of-life – this will increase overall costs and disruption to customers. Underinvestment can also increase long term costs through higher losses, more emergency interventions, and shortening of network asset life.
5. **System balancing costs would increase.** A lack of distribution network capacity will inhibit DER providing the services the NESO needs to balance the wider system as renewable energy penetration increases. Distribution network constraints are a barrier to DER participating in whole system markets.
6. **A barrier to economic growth.** A lack of demand capacity is a barrier to economic growth as it inhibits the connection/expansion of commercial customers, e.g. offices, retail, and industry.
7. **Creating a future deliverability problem.** If we postpone investment through underinvestment, we risk creating a higher and sharper increase in interventions in future price controls that is harder to deliver. We explain this in more detail in response to question 13.

The risks and of overinvestment

In contrast to underinvestment, the risks (the likelihood and the impact) of overinvestment are low.

The likelihood is low as all FES scenarios show demand and generation on the distribution network increasing out to 2045/2050. This will affect every voltage level and most parts of our network as it touches every aspect of society. Therefore, the likelihood of installing assets that turn out not to be required is very low. Some may be installed a few years early due to variations in consumer behaviour at a local level, but the likelihood of them not being needed at all is negligible.

We would also note that the cost impact of any overinvestment is low. For example, any extra financing costs of early investment (para 6.21) would be counterbalanced by efficiencies from a more coordinated delivery programme and a reduction in technical losses (newer assets typically incur lower losses than those they replace). Similarly, if more capacity is provided than is required, the financial impact of this is limited as, in the case of new circuits, the additional cost of a larger conductor is a marginal cost of the intervention.

Question 13. What are the benefits and risks to deliverability if network reinforcement is deferred to future periods?

There are significant risks to deferring network reinforcement that outweigh any potential minor benefits. Figure 3 of the framework consultation shows demand ramping up in the mid-2030s. Therefore, if we defer reinforcement until then, it will heighten and sharpen the increase in reinforcements that we need to deliver. This would make it more challenging and costly to deliver compared to a smoother delivery programme, as complex supply chains and DNO/contractor delivery resource struggle to accommodate step increases or decreases (even those that are predictable).

Where these delivery challenges result in capacity delays, it will have the same impact as for underinvestment (question 12): safety and reliability impacts, barriers to societal decarbonisation and connections for CP2030, higher network and system balancing costs, deliverability inefficiencies, and a barrier to economic growth. A smoother delivery profile out to 2050 will help avoid these adverse impacts and smooth out associated expenditure on customer bills.

Assets: transformers, conductors and switchgear

These are the three main electricity assets that constitute a network. We cannot increase network capacity without these. Deferring network reinforcements would result in a more rapid increase in demand for these assets that fixed capacity supply chains will struggle to deliver (as question 11 explains, we have already seen [REDACTED] increase in manufacturer lead times in the last five years). This will likely result in long delays, resulting in insufficient network capacity.

If Great Britain delays investment in decarbonisation, it risks competing for resources with other countries that are currently behind in their efforts. This competition could make it harder and more expensive to achieve decarbonisation goals.

DNO and contractor delivery resource

The supply chain challenge goes beyond assets – it also covers delivery resource. For example, it takes 5-6 years to train a linesman to the point that they can be deployed without supervision. Such personnel will be essential for delivery. The greater the step increase we need to deliver in recruitment and training, then the more prone we are to: shortages in recruits, insufficient capacity at training facilities, and likely a training catch 22 (you would need to take senior engineers away from delivering reinforcements to train apprentices, just as we need to be increasing delivery).

Considering greater use of contractors, the contractor market is sized to current market need and workforce is becoming increasingly localised as workers are less willing to travel (see question 11). They cannot rapidly expand any more easily than DNOs – they still need to train and equip their staff.

A real example – PCB replacements

Legislation came into force in 2019, for all assets with high levels of Polychlorinated Biphenyls (PCBs) to be removed by 2025. This resulted in a step increase in work in a short period (when you consider that it takes 5-6 years to train a linesman). This step increase had two impacts: the costs of contractors has gone up (as all DNOs try to secure resource to delivery this programme)

and it has become more complex to deliver other programmes on-time as resource has been diverted.

Summary

Supply chains are complex, and it only takes a couple of shortages to hold up delivery. The supply chain and DNO/contractor resourcing can increase capacity (we are recruiting 200% more trainees in ED2 than ED1), but it is much more manageable and less risky to customers with a smoother delivery programme. A sharper step increase, even one we accurately predict, will be harder to deliver. This increases the likelihood of capacity shortfalls, impacting safety, reliability, societal decarbonisation, connections for CP2030, network costs, system balancing costs, deliverability, and a barrier to economic growth.

So, from a deliverability perspective, we do not see any advantages in deferring reinforcement and then facing a higher and sharper spike in reinforcement requirements. In contrast, bringing forward delivery is low risk (as we explain in question 12) and helps ensure deliverability out to 2050. The resulting benefits far outweigh any tentative benefits that could result from deferral, such as holding on for the promise of new future innovations.

Question 14. What do you see as the role of distributed flexibility, both in the short and longer term, to manage distribution network constraints?

Distribution licensees will continue to use DER flexibility for distribution network purposes in ED3. Aligning with Ofgem's proposals to build the network capacity required to meet both CP2030 and accelerate towards net zero we will focus less on utilising flexibility to defer reinforcement until such time as it is deemed necessary. There are however a range of other use cases for flexibility on the distribution network that will be an integral part of the RII0 ED3 timeframe. This will primarily be to manage planned outages (for example when we need to carry out reinforcement or maintenance) and to increase the delivery efficiency of reinforcement programmes providing more choice as to when we start reinforcements so we can coordinate interventions and accommodate supply chain shortages.

The role of distribution flexibility on the distribution network

We consider that DER flexibility will have five distribution network use-cases in ED3:

1. To manage planned distribution network outages, for example when we need to carry out maintenance or make network upgrades. In ED2, we are increasingly using flexibility services during these outage periods to keep customer supplies secure and power flows within the remaining network limits. We expect this use will increase during ED3 as we will need to deliver more network reinforcements and so we will need to take more planned outages. This use case can be coordinated easily with the NESO as it is for a defined period and planned well in advance.
2. To manage network reinforcement programmes and support reinforcement delivery. This is where we use flexibility services as an interim solution to increase the delivery efficiency of reinforcement programmes. They give us more choice as to when we start reinforcements, so we can better coordinate interventions, 'smooth out' delivery, and accommodate supply chain shortages. This is not the same as using flexibility services

- for the purpose of deferring reinforcements. This use case can be coordinated easily with the NESO as it is for a defined period and planned well in advance.
3. Ensuring curtailment of curtailable customers does not exceed their Curtailment Limit. Ofgem's Access SCR reforms introduced a type of Curtailable Connection that has a Curtailment Limit. DNOs must endeavour to keep actual curtailment within this limit. Using DER flexibility services is one way we can potentially do this. This use case is less easily coordinated with the NESO than the first two use-cases as the extent to which DNOs will need to dispatch the service depends on several factors.
 4. In ED3 we would like to explore the opportunity to accelerate network connections prior to the completion of reinforcement works. Alongside the connections reform work that is ongoing to address the scale and complexity of connection queues in the UK we may also seek to use flexibility services to accelerate the connection of customers. Where it is technically and commercially feasible to do so this could provide a method to accelerate network connections ahead of planned reinforcements works that may be affected by supply chain, planning or other deliverability issues. This concept is not dissimilar to the technical limits approach or the Curtailable Connections approach but could be implemented without the requirement for extensive network and customer control equipment.
 5. As an alternative to network reinforcements, i.e. as a means of providing distribution network capacity. This use case is often referred to as deferring or avoiding reinforcement and was the primary driver for growing distribution flexibility markets in ED2. We think this role will be reduced in ED3, for the reasons Ofgem has set out in the consultation, but there may still be some edge cases where flexibility services are the right long-term intervention solution to provide network capacity. This use case is less easily coordinated with the NESO than the first two use-cases as it is usually for much longer periods, actual service dispatch is hard to predict as it often depends on real time consumer behaviour relative to network capacity, and the service provider can't operate in other markets during distribution service windows (once the decision has been made to use flexibility instead of a reinforcement, then we depend on that provider in those service windows).

The enabling role of the distribution licensee

We agree with Ofgem's view that DER flexibility will need to increasingly be used for wider system balancing by the NESO as the renewable generation penetration of the system increases. DER flexibility services can provide valuable sub-second frequency response, better match consumption with excess generation, and help manage transmission network constraints.

DNOs will be key to enabling this – we will need to do two main types of activity for this. First, DNOs will need to increase base distribution network capacity, as distribution network constraints are a barrier to DER participating in the wider system. Second, DNOs and the NESO will need to increase planning and operational coordination. This will take the form of data sharing, coordinating outages etc. This coordination will help ensure that the NESO and DNO have clear visibility of when DER services are available, that network power flows remain within limits, and that one party doesn't take an action that causes wider whole system costs.

Question 15. How do we ensure that network flexibility is used only when it is in consumers' long-term interests in ED3?

We agree with the principle used in ED2: that all technically viable interventions (including flexibility services) should be fairly compared in an unbiased manner. We do not think this principle should change – we should always be aiming for the best overall solution. The CBA methodology used to make this comparison (e.g. the CEM Tool) should be updated to better reflect consumers' long-term needs. For example, the CBA methodology comparing interventions should include:

- The cost impact of DER flexibility not being available to help balance the system as renewable penetration increases (and more generally the cost of fewer market participants in NESO markets). This cost would increase for solutions that deliver less 'base' network capacity, or only deliver it for certain times of day/year (e.g. active voltage management) or durations (e.g. using enhanced ratings), as these will all restrict the ability of DER to provide services to the NESO.
- The cost to society (including carbon cost and impact on economic growth) of delayed connections (everything from consumer LCT uptake through to large renewable generation projects and industrial demand). This cost would increase for solutions that take a long time to deliver, deliver less network capacity, or only deliver capacity for certain times of day/year or durations.
- The benefits of a smoother deliverability programme, including on the supply chain. This benefit would increase for solutions that help avoid a step increase in reinforcements in the mid-2030s.

The CBA methodology should continue to recognise that the correct intervention may be a sequence of solutions (e.g. flexibility or enhanced ratings as an interim until a reinforcement is delivered).

In addition to a CBA methodology, the technical viability of solutions should continue to be considered. For example, can it deliver for customers in the timeframes required, does it result in knock-on technical impacts etc.

Our approach is currently outlined within our published Decision-Making Framework⁶, outlining how we determine the optimal lifecycle solution to resolve network constraints. The outcome of this approach is also published on a site-by-site basis in our Distribution Network Option Assessments (DNOAs)⁷. Our network interventions were also extensively justified through the publication of our Engineering Justification Papers (EJPs)⁸. It is our view that by taking cognisance of the recommendations above and through appropriately updated governance processes we will be able to demonstrate that the use of network flexibility will be deployed only when it represents the long-term interests of consumers.

⁶ [SP Energy Networks Decision Making Framework](#)

⁷ [SP Energy Networks DNOA pages](#)

⁸ [SP Energy Networks EJPs](#)

Question 16. How are unexpected constraints dealt with currently? How quickly can these be eased, and what is the impact of these unexpected constraints (e.g. on LCT uptake)?

We have four main solutions for unexpected constraints: network reconfiguration, enhanced ratings, flexibility services, and fast-track reactive reinforcement.

Unexpected constraints have several impacts, including network overloads (impacting safety, reliability, and non-load costs), connection and decarbonisation delays, increased DNO expenditure, and wider system costs. Whilst unexpected constraints will always be a feature, we work hard to reduce them by increasing the accuracy of our forecasting and network assessment processes.

How we deal with unexpected constraints

We have four options that we can deploy quickly:

1. **Network reconfiguration.** This is where we change the topography of the network to move demand around to manage within network capacity. It is low cost, quick to implement, and can be easily reversed. However, we can only transfer demand to neighbouring sections of the network, therefore it is limited by the spare capacity on those neighbouring sections.
2. **Using enhanced asset ratings.** Some assets such as transformers can have an enhanced short-term rating that can be used for short periods, such as during outages or emergencies. For example, a transformer may have a nameplate rating of 7.5MVA but may be loaded up to 10MVA for short periods, depending on load profile. Extended use of short-term ratings can increase asset deterioration rates and reduce asset life.
3. **Flexibility services.** These may be procured in our flexibility tender rounds or, where time is pressing and it is clear only a few providers can technically resolve the constraint, via bilateral engagement. The time to tender via the flexibility tender rounds depends on how close we are to our next monthly tender.
4. **Fast-track reactive reinforcement.** This is more feasible for LV and HV networks, where the projects are simpler and there is a low lead-time on cables and transformers (we may hold them in stock). However, reactive reinforcements cannot be coordinated with other interventions, so can be less efficient than planned reinforcements, and they may delay other delivery programmes by pulling away delivery resources.

We would use Options 1 and 2 as interim solutions only, to manage the constraint until we can deliver an enduring solution.

The impact of unexpected constraints

- **Network overloads:** where we or customers are not immediately aware of the constraint (e.g. in areas of LV network with low network visibility) then the network assets may be overloaded. This risks safety issues and, where the asset fails, loss of supply to customers. Where the asset does not fail, running assets above their rating results in increased asset deterioration, and so higher asset management costs.
- **Connection and decarbonisation delays:** This may involve delaying LCT installations at lower voltages. Unexpected capacity constraints are rarer at higher voltages, but can still occur due to unexpected customer behaviour (e.g. a factory going on strike, which

reduces network demand and so creates an export constraint). These unexpected constraints will result in delayed connections and increased curtailment of flexibly connected customers.

- **Distribution cost impact:** unplanned reactive reinforcements typically cost significantly more than planned proactive reinforcements. There is both an increased capex cost and the cost impact on other programmes (e.g. the impact of redirected resource or assets).
- **Whole system cost impact:** network constraints are a barrier to DER providing the NESO with system balancing services (and participating in other whole system activities).

Increasing our foresight of constraints

We have put a lot of work into our enhanced forecasting and modelling tools to reduce the likelihood of unexpected constraints (although these can never be reduced to zero). This process gives us good insight into where and when network constraints are likely manifest across our network.

Question 17. Do you agree that the tRESP output outlined for early 2026 will help create a level playing field for DNOs' business planning and support the ED3 objective and consumer outcomes?

Our answer to this question is caveated with the observation that RESP and tRESP are still being created and so subject to change, and that there are still varying interpretations of what they will actually do and the form of the outputs. Our understanding is that the RESP sets the cross-vector foundations for identifying capacity needs, and DNOs retain responsibility for forecasting, optioneering, and developing investment plans based on these higher-level strategic RESP outputs. We understand that it will not define the interventions DNOs need to make, although it may identify opportunities for strategic investment following discussions with the DNO. Based on our understanding of the tRESP, we think the proposed tRESP outputs will help create a more level playing field and make it easier to benchmark ED3 Business Plans. We agree that the proposed tRESP outputs would support the ED3 objective and the first consumer outcome "Networks for net zero". We think the proposed tRESP outputs are neutral for the other three consumer outcomes.

We have given our detailed views on RESP in our response to Ofgem's October 2024 RESP consultation. In summary, in relation to the proposals in paragraph 6.34:

- We see the value of whole system pathways and agree that DNOs should use the tRESP as a foundational input into DFES modelling.
- The tRESP short-term pathway will inform the ED3 baseline. Given the context of ED3, the positive role of anticipatory investment, and the need to meet long-term decarbonisation goals, the tRESP pathway needs to be based on a higher FES scenario than Ofgem used for ED2.
- The timescales of the tRESP outputs and development of DNOs ED3 plans are challenging. To make this work it will be essential for DNOs and the NESO RESP team to work in very close collaboration throughout 2025 to validate regional forecasts and ensure that regional variations are captured within the tRESP pathways. This is to ensure that there are 'no surprises' in the tRESP outputs and that DNOs have sufficient time to

undertake the in-depth assessment, optioneering, stakeholder testing, and external assurance processes required for a well-justified ED3 plan. We believe this aligns with the discussions around processes in the recent Ofgem RESP working groups.

- Granularity of the tRESP outputs: the pathways should be disaggregated to RESP regions as well as DNO licence areas to enable these to be reflected in business planning. These should be able to be disaggregated to Local Authority level to enable stakeholder engagement, and to help transposition between geographical boundaries. Developing pathways to very granular LSOA level would risk RESP getting bogged down in the relative minutiae and losing sight that its primary value comes from its higher-level strategic coordination and direction role.
- Consistent assumptions are a good way to create a level playing field, provided there is an acceptable range of variation to take account of facts on the ground (e.g. different housing stock will impact heating load and so peak heating demand; rural vs urban will inform daily EV use and so peak charging demand etc.). However, too broad a range will erode the benefits of consistent assumptions. We therefore propose that the assumption range includes notes explaining their use. Such an approach would support the ethos of consistently applied assumptions.

Question 18. Can anticipatory network reinforcement be used to smooth the long-term build profile to avoid creating pinch points for the supply chain and workforce? What are the risks and trade-offs?

Yes, anticipatory investment can smooth the long-term build profile by pulling forward investment. This is valuable to avoid creating pinch points and to ensure the supply chain and delivery resource can deliver the increased volumes needed. The risks are low and are far outweighed by the benefits: capacity ready when customers need it (CP2030, LCT uptake, GB decarbonisation), lower risk of network overload (safety, reliability, and cost), supply chain can deliver volumes, and overall investment is more efficient (can better coordinate and deliver interventions).

Our response to this question should be read in conjunction with questions 11, 12, and 13, as they cover overlapping topics.

The benefit of anticipatory investment

As we explain in question 13, it is more challenging for supply chains and delivery resource to accommodate step changes (even those that are predictable). So, from a deliverability perspective, anticipatory investment means the supply chain and workforce can deliver the interventions required for net zero more efficiently and with lower risk to customers. It can help manage stock levels in our depots and avoid the costs of having to expand our depot capacity. It helps avoid shortages in one part of the supply chain that have knock-on delays on the rest of the delivery programme.

In the context of long-term increasing demand and generation, this deliverability benefit provides key customer and societal benefits:

- **The capacity is ready when customers need it.** This supports LCT uptake and decarbonisation, helps meet CP2030 and 2045/2050 targets, and reduces barriers to DER providing essential system balancing services to the NESO.
- **There is a lower risk of the network being overloaded.** This has safety, reliability, and asset health benefits.
- **Investment is more efficient,** as we can better coordinate load and non-load interventions (e.g. replacing a poor condition cut-out fuse (non-load) at the same time as upgrading the looped service (load)). This in turn results in less disruption to customers and fewer planned outages, road closures etc.

The risks of anticipatory investment

In contrast to the benefits, the risks of anticipatory investment are minor. As we explain in question 12:

- All FES scenarios show demand and generation on the distribution network increasing out to 2045/2050. This will affect every voltage level and most parts of our network as it touches every aspect of society. Therefore, the likelihood of installing assets that turn out not to be required is very low.
- The extra financing cost of early investment can be balanced by the financial savings from coordinating delivery and losses reduction from installing newer assets.
- In some instances, decisions might be more optimal if they were delayed until the future when more information is available. However, given the standardised nature of solutions at lower voltages, the marginal cost increase of oversizing circuit solutions, and the often-long lead times at higher voltages, the potential benefits of this are considerably outweighed by delaying decisions. To quote the NESO “Clean power by 2030 is a huge challenge that will only be met by...prioritising pace over perfection” (source: CP2030 Executive Summary).

A real example – anticipatory looped service interventions

Over 550,000 of our customers are connected by looped services. This is where multiple properties share a single service cable. These looped services do not have sufficient capacity to accommodate EV chargers and/or heat pumps. This means we need to replace ca. 80% of them by 2045/2050 – this is one of our major load programmes from ED2 onwards.

Consider a street of 40 properties served by 20 looped services. We have two delivery options: we replace them reactively as the need arises (how these interventions were done before ED2 when volumes were low), or we replace them all (street-at-a-time) before the first looped service constraint occurs (i.e. an anticipatory approach).

The reactive approach requires us to visit the street up to 20 times, whereas the anticipatory approach requires us to visit the street just once. This has cost benefits (we can share fixed overheads across multiple loop services), is less disruptive (we’re only digging up their street once), means the customers already have the capacity when they need it and ensures that the volumes are deliverable – these are all in customers’ interests. We can also coordinate the work with replacing poor condition cut-out fuses (a non-load investment programme) and local HV network reinforcement.

Question 19. Do you agree that investment optioneering should aim to reduce the lifetime costs by sizing elements of works for long-term need, including considering the impact of thermal losses?

We agree, investment optioneering should always:

- Assess and compare potential interventions in a fair manner and accurately capture their costs and benefits. Our response to question 15 lists some of the factors that cost benefit assessments should consider.
- Consider the long-term view. This is because some of the interventions to provide network capacity will last for decades. We therefore need to consider long-term needs to ensure that we know when it is efficient to use shorter-term or longer-term interventions.

This approach ensures we are identifying the most beneficial investments (which may be a combination of non-capex solutions) by fairly comparing their costs and benefits and avoids short-sighted investment decisions that end up costing customers more by not considering long-term needs.

Where this process shows that a long-term fixed-capacity intervention (e.g. a new transformer) is the most beneficial approach, we expect it will show that sizing it to long-term need is most beneficial. This is because, when it comes to reinforcement interventions, a ‘touch the network once’ approach is nearly always more financially efficient than having to make multiple interventions on the same asset (which also carries greater risks to decarbonisation, network reliability, safety, exacerbating supply chain challenges etc).

Question 20. Is a 5-year price control (2028-33) the right duration to achieve the objective of securing timely network capacity for the net zero transition at least cost to consumers over the long run?

We are not supportive of any suggestion to shorten the price control any further than the current 5-year period. A perpetual cycle of price controls will be an inefficient way to spend resource for Ofgem, companies and wider stakeholders.

Ofgem could consider returning to a longer price control period. For example, to reflect linkages with significant RESP output, it might be worth exploring the possibility of lengthening the period slightly to six years to better align with the full RESP update every three years (as proposed). However, more clarity will be needed on the difference between the annual RESP update and the full RESP update every three years, and as set out above, to ascertain if alignment with the RESP cycle is required or desirable.

Question 21. To what extent should the price control be more directive on specific anticipatory and strategic investments to achieve the ‘networks for net zero’ consumer outcome?

As outlined in more detail in our responses to questions 3 and 8, whilst we continue to believe an output-based framework should remain at the core of the ED3 regulatory framework, we also

understand that the introduction of the RESP, CSNP and SSEP bring with it a shift towards a more strategically planned energy system, and we understand that the ED3 framework needs to operate within that context. Therefore, we do agree that there could be situations where certain strategic investment input recommendations could be made within the tRESP/RESP e.g. a strategic high value primary substation. However, we firmly believe that these recommendations should not be imposed on DNOs or be a surprise to them. They should only be made following recommendations by and discussions with DNOs. Network planning responsibilities sit with the DNO, so any such recommendations could only be included if they have endorsement upfront from the DNO.

Question 22. Do you agree with our characterisation of strategic and anticipatory investment and our expectation that these activities would have different regulatory drivers and controls?

We agree with Ofgem’s characterisation of strategic investment as large bespoke projects or network-wide programmes of smaller upgrades, and anticipatory investment as being investment ahead of uncertain need. However, there is often an overlap. For example, replacing looped services is strategically important to enable LCT uptake, and delivering them in a proactive anticipatory manner is the most efficient (as we explain at the end of question 18).

In the context of the tRESP containing recommendation on strategic investment, we do not agree that these should include recommendations around programmes of smaller upgrades. This is because we would not expect the NESO to be involved in discussions around the network need at such a granular level. Neither would we expect any adoption of PCDs for strategic investment to include the programmes of smaller upgrades. Use of PCDs would be practical as the PCD framework has not been set up to manage such granularity. On smaller projects it’s in customer interest for there to be flexibility for DNOs to respond to emerging asset risks and load requirements.

Our response to question 4 outlines the controls that could potentially be applied to such investments.

Question 23. Should the price control provide more guidance or guardrails around the use of particular network solutions to achieve the ‘networks for net zero’ consumer outcome?

DNOs have a statutory duty to maintain an efficient, coordinated and economical system of electricity distribution and it is our responsibility to plan our network and make investment decisions. Any guidance or guardrails around the use of particular network solutions could introduce unintended consequences and conflict with these duties. It is therefore essential that if any such guidance is to be developed then DNOs would need to be heavily involved in the process.

In terms of specific guidance, as outlined in our response to question 15, we would expect the CBA assessment methodology we use to choose between solutions to be updated and to be a common DNO methodology.

Question 24. Should we consider how we might bring all network capex investment together within the framework, irrespective of driver (e.g. load, asset health, resilience), to ensure a common approach to future proofing and delivery?

We do not believe that integrating asset health and load within the same mechanism is necessary to ensure a common approach to future proofing and delivery.

We already proactively and holistically approach the assessment of all drivers when considering the best intervention for our network assets. This is possible through use of the current RIIO framework mechanisms and sufficient planning to ensure the scope of all investment considers network requirements and drivers appropriately.

We would support any development in the framework which simplifies the funding and reporting of investments and drives a common approach across the industry. As an example of a successful approach, we wish to highlight CNAIM which ensures alignment and consistency by ensuring network companies are benchmarked in a consistent manner. However, we ask Ofgem to note that it would be unfortunate if any development in this area inadvertently hindered the successes of the current framework to support this or already well-developed funding and reporting processes.

In the current drive for net zero and the future demand on the network we are seeing delivery challenges on the supply chain and skilled labour. It is crucial that limited DNO resources are utilised effectively. This means it is critically important that whilst proactive and anticipatory investments are enabled, that any capex investments are the most efficient interventions that holistically offer the greatest benefit and deliver against most drivers e.g. ensuring climate resilience and reducing asset risk. It is also critically important that regulatory incentive and funding mechanisms stimulate and support the supply chain i.e. if volume drivers with insufficient unit costs are employed it will harm DNOs ability to deliver rather than to stimulate and attract the supply chain to deliver.

Making sure we make the right investment decisions now to future proof the network protects the consumer against constraints, reliability issues and additional costs of re-visits in the future.

Responsible Business

Question 25. How can we better strengthen accountability for consumer outcomes?

We agree regulated monopolies should be held to account to ensure they deliver good outcomes for consumers. There is a high reporting burden on DNOs currently with a large amount of data being shared with the regulator via reporting packs. Alongside this, there are various reputational incentives that require DNOs to report on performance in specific areas, such as major connections, vulnerable consumers and the environment.

Ofgem has in the past published annual reports, with the latest being the 21/22 ED1 annual report, which provide stakeholders with analysis and data on DNO performance.⁹ These reports provide a wealth of data on DNO performance and are supported by comprehensive data files based on DNO reporting.

We support Ofgem picking up this piece of work again and to publish these reports relatively closely after DNOs are required to submit our annual data to Ofgem.

We would caution against pursuing a path to make all data submitted by DNOs to Ofgem public. A large portion of the data will already be included in Ofgem's annual report supplementary data tables, and it would likely be a large task to go through all the data tables and see what data might be commercially sensitive. A better approach would be to identify gaps where stakeholders desire to have more information. We must also not underestimate the importance of Ofgem's analysis and collation of the key indicators, both to ensure the data is trusted, but also to make it much more accessible than the raw data in the RRP tables.

We support, in principle, the ambition to move away from tabular spreadsheet (Excel) based data. A key requirement, in so doing, would be to deliver better integrated, more accessible, and intuitive platforms which provide higher quality information to stakeholders. The best starting point for such a transformation would be to consider fundamental principles and data requirements and how they can be delivered through new technologies i.e., thinking outside the 'box' that forms the existing data templates.

Question 26. What are your views on ED company reporting and the overall transparency of performance and compliance?

We understand and fully support entities of critical national importance meeting the highest standards of financial reporting. SPEN aim to be at the vanguard of promoting transparency of performance and the returns. Overall, we believe existing company reporting is understood by knowledgeable users and consistency is important to users. However, we also need to ensure reporting is meaningful and we avoid regulatory burden without any associated benefit.

We believe the existing suite of regulatory reporting is fit for purpose, and we have not received any requests from stakeholders for additional information.

The Regulatory Financial Performance Report (RFPR) aims to produce a comprehensive, transparent, accessible, and accurate measure of network company Financial Performance under the RIIO framework. The RFPRs comprise two main elements:

1. RFPR templates for reporting the data; and
2. This RFPR commentary and supporting information document to be read alongside the tables

The report consists of the different areas of Network Owners (NWO's) activities, including expenditure (totex), output incentives, innovation, financing, and tax among others.

⁹ [RIIO-1 Electricity Distribution Annual Report 2021-22 and Regulatory Financial Performance Annex to RIIO-1 Annual Reports | Ofgem](#)

For each of these elements the NWO's actual costs and revenues are compared against allowances (i.e., what NWO's are funded for), the difference between these forming the basis of NWO performance. Performance is shown in the form of Return on Regulatory Equity (RoRE)

The RoRE measure of performance is beneficial for comparison across the industry. It is important to note that while performance can be earned during the RIIO price control this is often not realised in income and expenditure during the period. Regulatory mechanisms mean this can take up to 45 years, so there remains significant uncertainty in realising this performance. Performance for specific years or across the period should not be seen as related to profits received in that year/period.

In terms of proposing a preferred metric to RoRE, we strongly advocate the Return on Capital Employed (RoCE) as the most appropriate performance metric for the purpose of reporting company returns. The RoCE metric is defined as the earnings before interest and tax (EBIT) divided by total assets, less current liabilities. EBIT is used as it measures the return available to meet both equity and debt holders before the impact of taxation. It best reflects operational performance since it is unaffected by corporate and tax structures. It is a commonly used and understood measure of profitability across many industries. For example, the CMA used RoCE as a principal profitability measure in the GB energy market investigation.¹⁰

A critical area of improvement would be for Ofgem to set out greater context and information around Ofgem's calculation methodology for the basis of the RoRE performance measure. Company performance, notably the cost of debt (CoD) allowance for Network Owners is an area that causes confusion. There is a lack of understanding that companies' annual CoD allowance does not cover the actual annual cash outflows for interest and shareholders are required to fund interest payments in excess of allowance. We believe this should be addressed through actions including prominently explaining that the cost of debt is partly provided on a real basis while the interest rate on the majority of company's debt is on a nominal basis.

To illustrate this point further, Ofgem's methodology within the RFPR tables presents companies borrowing costs as a negative value during times of high inflation, asserting that companies face no costs to borrow money for the purposes of calculating performance. This is not the case and highly misleading. The current methodology misrepresents the performance over the full 45-year depreciation period as if it were an in-year return, this is of particular issue in the recent high inflationary environment.

During RIIO-2 a number of additional reporting requirements have also been added for DNO's with a particular focus on wider corporate governance & compliance such as company structures and dividend reporting. We believe that these additions have benefited consumers by providing additional visibility of decision making which has aided the wider transparency of the sector as a whole.

¹⁰ *CMA Energy market investigation (2016). Final Report, Appendix 9.9, Approach to profitability and financial analysis, paragraphs 23-25).*

Question 27. Do you consider that ISGs alone are sufficient to ensure high quality and effective consumer and stakeholder engagement throughout the ED3 price control? What alternative or complementary approaches should we consider?

We consider that ISGs are sufficient to ensure high quality and effective consumer and stakeholder engagement during the ED3 price control. The ISG plays an essential role in reviewing engagement we would carry out with a diverse population of external stakeholders. SP Energy Networks already has an ISG in place through our Independent Net Zero Advisory Council (INZAC).¹¹ The INZAC was established in 2022 and brings together 15 external experts to provide challenge and specialist knowledge to our distribution and transmission businesses.

To be clear, we do not consider the ISG itself is sufficient as the sole engagement mechanism throughout the ED3 price control. We work closely with our ISG, ensuring transparency and continuous improvement of our stakeholder engagement strategies. Our ISG has a broad range of stakeholder and consumer representatives who are able to review our stakeholder mapping, engagement plans and delivery.

We do not believe further scrutiny on our stakeholder engagement beyond the ISG is required, however a complementary approach could be an independent audit standard/measurement i.e. AccountAbility who oversee the AA1000 Stakeholder Engagement Standard. This can aid a drive towards consistent standards across the industry.

It will be essential that the NESO, when developing the RESP, coordinates effectively with DNOs as part of their local stakeholder engagement to avoid potential duplication, confusion or stakeholder fatigue. We currently have strong local stakeholder engagement with local, regional and national governments and we aim to retain these strong relationships to support our network development and allowing effective engagement with RESP development.

Question 28. Do you agree that Ofgem should adopt research approaches, such as deliberative techniques to ensure that the consumer voice is heard and considered throughout the ED3 and company Business Plan process?

We agree that comprehensive research approaches should be adopted including deliberative techniques, however this needs to be sensible and the guidelines and expectation from Ofgem should be clear. Customer research is costly and ultimately the customer pays for this research. That said plans need to be shaped by customer feedback and it should be completed in the most efficient way.

We would support Ofgem undertaking its own consumer research, however only if this did not duplicate with that expected of DNOs, to ensure there is no duplication of costs for customers. Clarity of timing, expectations and roles is therefore essential.

¹¹ [Independent Net Zero Advisory Council \(INZAC\) - SP Energy Networks](#)

Question 29. How should our approach to enhanced stakeholder engagement be adapted to better include the perspectives of all vulnerable customers, including those that are seldom heard, digitally disengaged/excluded and those that are worst served?

We note that Ofgem in the consultation document states that network companies “*should demonstrate how have developed their own inclusive research and stakeholder engagement programmes to ensure that consumer views are effectively accounted for in the ED3 process*”.

As a DNO, we take our responsibility to consumers very seriously and have robust processes in place to ensure our plans take into account the views of those who might struggle to make themselves heard. As part of our engagement and research in ED2, our research was undertaken by an independent research company. As part of this process, we segmented our customer base and ensured we obtained a statistically representative response, with set quotas, from multiple vulnerable customer groups. This included:

- Customers in, or at risk of, fuel poverty.
- Customers in low-income communities.
- Customers with little or no educational qualifications
- Customers from ethnic minorities
- Customers off gas grid
- Customer classed as “digitally excluded”.
- Customers with physical or mental vulnerabilities.

We also engaged with other key stakeholders in this area, including energy charity workers and specialist / hard to reach commercial customers. We adopted a broad range of research methods to ensure we obtained these quotas, including online, telephone and face to face interviews.

We would propose to adopt a similar approach in ED3 and building further on these robust foundations. We would look to also utilise wider demographic data developed during ED2, which we now have available, to enable us to target hard to reach areas and communities, and also use our network performance data to ensure these inputs are triangulated, to give us a picture of network impact in hardest to reach communities.

We believe our approach is very robust, but we would welcome any views from Ofgem on whether there is anything more that is expected of DNOs.

Question 30. What alternative or additional approaches might we use to ensure that the consumer voice remains central to our policy setting process?

We believe that complementary consumer research from Ofgem would be beneficial to provide it with comfort and checks on the robust engagement and research approach DNOs are taking. As set out before, we believe this should not replace DNO research, and not duplicate the comprehensive work DNOs are doing with their ISGs or broader stakeholder engagement. There should be clarity in terms of expectations from DNOs and the role the regulator will play. On top

of this, the ISG governance process should provide Ofgem with further assurance that DNO take stakeholder engagement seriously.

Question 31. Has the BMCS incentive served its purpose in driving performance improvements and how can we adapt the metrics to better incentivise performance across a wider range of interactions between DNOs and their customers, particularly relating to connections?

The BMCS incentive has been a real success in driving exceptional customer service and satisfaction. DNOs have worked hard to ensure excellent customer service driven by the incentive and our performance has outperformed the best companies in the Institute of Customer Service UK Customer Satisfaction Index.¹²

This incentive should remain unchanged in ED3. The double-sided (reward and penalty) incentive encourages DNOs to continuously invest in customer service and strive to deliver better service in the expectation of incentive rewards. In a world where customer expectation is continually evolving, now is not the time to reduce the focus on striving for customer service excellence. Especially as more and more new customers will come into contact with the DNO, as they install low carbon technologies, and the customer base evolves with growing expectations of tailored service and technology solutions.

It is clear to see that the increase in satisfaction targets has created a greater separation in DNO results compared to ED1. The most ambitious DNOs (including SPEN) are now being rewarded for their greater ambition and performance levels, compared to those with lesser ambitions, who are receiving no reward or are in penalty. This was the key aim of the changes in ED2, and the initial results are indicating this approach has been successful in only rewarding truly excellent customer service performance. It would be a poor outcome for consumers if Ofgem would reduce its ambition on customer service and stop encouraging DNOs to investment in continuous improvement and innovation, at such a crucial moment in the net zero transition.

We would welcome more clarity on Ofgem's thinking when it comes to adapting the BMCS to reflect the wide range of interactions between DNOs and customers. The BMCS already includes a 50% weighting towards connections, and a general inquiries category (20%) which captures the wide range of interactions between DNOs and customers.

Question 32. How should the CVI be adapted for ED3, and should we consider greater alignment with the GD sector?

The CVI has in the main worked well in the first year of ED2, for such a new incentive. We have invested a lot of time and effort to ensure we proactively target, sign-up and support customers on our Priority Services Register. Initiatives have included:

- Using a wide range of recruitment channels, including regional in-person engagement and outreach as well as strong partnerships nationally and with local organisations.

¹² [UK Customer Satisfaction Index \(UKCSI\) • Institute of Customer Service](#)

- Through our VEST innovation project, we created a ‘risk of being left behind’ (in the energy transition) index, which we use combined with other sources to provide a first-of-a-kind ‘unified’ view of vulnerability.

We are proud of what we have achieved in this area and supporting our vulnerable customers.

Our main challenge has been to start delivering support service for low carbon technologies, as DNO’s have struggled to find suitable partners to deliver the volume of support required to meet the targets outlined in the incentive.

Consideration should be given to widening the scope of services deemed eligible for DNOs to deliver, as currently there are a number of areas deemed out of scope of this incentive, but which would deliver significant benefits to customers most in need of support. Examples of this being:

- DNOs providing energy saving advice & equipment.
- DNOs offering wider social support services to vulnerable customers, e.g. befriending services.

We would like to better understand Ofgem’s analysis of any gaps they believe in protections for customers in vulnerable circumstances that sits behind the question being asked on whether further alignment of standards between gas and electricity distribution is needed. We believe licence obligations are already generally aligned. We note Ofgem makes the point that one Guaranteed Standard of Performance (GSoP) (to provide alternative heating and cooking facilities for PSR customers in case of gas outages of a certain duration) does not apply to electricity customers. This makes sense in the situation where gas is the dominant fuel source for heating and cooking. However, we already provide, without a guaranteed standard in place, a range of support for PSR customers when they are off supply for a longer period of time. In our Consumer Vulnerability Strategy, as part of our ED2 business plan, we set out a range of support we provide to vulnerable customers in a power cut.¹³

These services include:

- Proactive customer contact.
- Additional welfare calls to our most vulnerable customers.
- Contacting carers and families.
- Providing hot food and drinks where needed.
- Providing welfare support such as facilities.
- Support packs.
- Hotels.
- Generators.
- Uplifting medical supplies; and
- Understanding and acting on any other’s needs.

¹³ spenergynetworks.co.uk/userfiles/file/Annex_4B.1-Consumer_Vulnerability.pdf

We believe this comprehensive approach is sufficient to provide strong support for our most vulnerable customers in case of a power cut.

Question 33. Should DNOs have a role in delivering energy efficiency measures to homes and businesses? What might the scope of these services be and how should they be funded?

We do not believe DNOs should play any major role in the installation of energy efficiency measures. Government programmes such as government Warm Homes Plan, ECO4 and the Great British insulation Scheme provide a broad range of energy efficiency interventions already.¹⁴ Introducing a major role for DNOs in this area would not be appropriate in this context. We believe this is still an area where government should play a primary role.

However, as per our answer to question 32, we believe that the delivery of energy efficiency advice and equipment should be reconsidered for inclusion in the scope of the CVI. Using this incentive ensures that the customers to whom these services are provided are those most in need. A role for DNOs through this incentive could be an efficient way to increase energy efficiency.

Beyond this, it will be worth exploring whether a separate Vulnerability Fund might add consumer benefit in this area, building on top of the services delivered under the CVI. This could include a separate fund for community organisations at the nexus of fuel poverty and the net zero transition. This could include funding for broader projects that both address fuel poverty (including energy efficiency) challenges and those who are most at risk of being left behind in the energy transition, but who may not qualify for existing government funding. This could operate similar to SP Transmission Net Zero fund (which is a “Use It or Lose It”), with organisations having to apply to the fund and justifying the need for investment. Some of these projects have included retrofits.

Question 34. How can we drive further service improvements under the TTC incentive?

Ofgem has already made TTC targets tougher between ED1 and ED2. We are pleased that Ofgem’s consultation acknowledges that there is a natural floor on how short these targets can be because of the nature of connecting and the activities involved in the process and would urge Ofgem to resist any suggestion that these targets are tightened any more. In fact, we would go even further and suggest that additional factors outwith the DNOs control are properly considered when setting the targets for ED3.

We have already seen our volume of Low Voltage connections increase – since 2023 our volume of LCT applications have doubled and the focus on net zero will further increase this. We believe the changing volume and circumstances surrounding these requests needs to be reflected in the

¹⁴ [Help to save households money and deliver cleaner heat to homes - GOV.UK; Great British Insulation Scheme | Ofgem; Energy Company Obligation \(ECO\) | Ofgem](#)

targets for this incentive. Increased volumes bring more challenging and time-consuming jobs, and the TTC incentive in ED3 should reflect these changes.

For example, we are already seeing some companies submitting a high volume of quotation requests in a short period of time related to initiatives that have been approved to meet net zero targets. This can have a significant effect on workload and detrimentally impact average performances. We believe Ofgem should consider the impact that this type of submission model has on offer timelines and revise expectations for ED3. Perhaps revising targets or creating exceptions if volume of requests on a particular day exceeds a certain threshold. It would also be a good opportunity to take stock to assess if there are other industry challenges around TTC need to be considered differently under the incentive. For example, as the need to access highways grows, access is becoming more challenging with highway authority use of lane rental schemes posing greater risks for TTC delay.

Question 35. Should the TTC also apply to domestic connection upgrades i.e. fuse/cutout/service cable upgrades, including unlooping?

We recognise Ofgem’s desire to improve the focus on performance in these areas as they are key to the net zero transition. However, whether or not this is feasible requires further thought and we urge caution for a number of reasons.

- **Target setting for the other areas:** The rate of increase in volumes experienced in these areas will make it challenging to both set and achieve targets in this area. Volumes must be factored into target setting, and historic performance cannot be used to set future targets. Since 2023 our volume of LCT applications has doubled and this rate of growth is only moving in one direction. Ofgem should take the time to gather data and understand future trajectories to establish realistic targets and phase these in overtime and certainly without any penalty risk until confidence in the mechanism can be established.
- **Unlooping:** We agree that unlooping will be an important activity during ED3, and it is right for customers to expect a high level of service. However, we do not believe that expanding the scope of the TTC mechanism would be the best way to do this and thought should be given to developing an incentive which would capture both proactive and reactive unlooping activities to avoid the unintended consequences of prioritising reactive jobs over proactive. Any incentive in this area should also reflect the circumstances under which unlooping takes place. For example, trying to get neighbours to agree to unlooping can be challenging particularly if they are not the customers requiring the upgrade work. This can mean excavating their driveway to install a new service. This disruption is often undesirable and consequently takes a lengthy timescale to agree solutions.

Question 36. What is the best approach towards incentivising services to major connections customers and how should the MCI be adapted for ED3?

The successful delivery of connections to our larger customers is a fundamental element of the current price control and will continue to grow in scale and importance during ED3.

The connections queue issues and capacity constraints across networks are well documented and the subject of wholesale industry scrutiny, so we do not repeat these here. It is incredibly challenging to achieve customer satisfaction amidst such a landscape, especially with our major connections customers where their needs are generally more complex. For example, we have experience of large demand customers (such as hospitals) with requirements that may have only required us to invest in an upgraded secondary substation in the past but are now requiring more complex and time-consuming primary substation investment. Another example of challenging customer interaction in the current environment is that one of our major customers with plans to decarbonise their commercial processes brought Local Authority representation to our connections discussions where the Authority highlighted their concerns that the demand customer would take all the capacity that they needed for new housing in a nearby location.

Providing these stakeholders with accurate, comprehensive and yet simple information to suit their needs is a resource intensive and challenging process. Stakeholder frustrations can run high, and our staff have to manage a growing number of these complex relationships. We believe it is important that the MCI framework should recognise these challenges and the level of effort that is required to reach an outcome that is satisfactory to our customers. In this environment, a score above target should be recognised as incredibly good. Given these challenges, and to reflect the level of investment required to deliver, we feel that DNO effort should be able to benefit from reward under the MCI and not just face the risk of penalty. We would urge Ofgem to make the MCI incentive a symmetrical penalty/reward incentive in ED3. Notwithstanding the above, we believe that the main way in which services to major connections customers can be improved is by ensuring that our network has sufficient capacity within an acceptable timeline. We believe Ofgem's supportive policy stance on anticipatory investment is helpful to this, but the detail of the ED3 framework needs to develop in such a way that this investment (supported by DNO shareholders) can materialise.

Question 37. How should the ED3 framework adapt to ensure that customers connecting to the distribution network are provided with the service that they need from the DNOs?

When considering the future framework required to ensure that customers connecting to the distribution network are provided with the service that they need from network operators, it first needs to review where we are now. The connections queue has reached over 730 GW across transmission and distribution (168GW for distribution), far more than will be needed under future demand scenarios and as a result it takes too long to connect the generation and demand GB needs to meet net zero, with some projects receiving connection dates beyond 2035. The current approach to connection applications of "first come, first connected" is no longer appropriate and we fully support the Connections Reforms proposals, which are aligned with Clean Power 2030, under development to introduce a "first ready, first needed, first connected" approach. This will facilitate the design of a more coordinated system and potentially free up

network capacity for projects proven to be progressing, helping to deliver CP2030 and net zero ambitions. However, it should be recognised that significant infrastructure will still be needed to facilitate those required projects.

We consider that the RIIO framework should remain at the core of the future regulatory framework, which has, by incentivising output delivery been successful in driving step change in improvements across key areas that matter to customers including customer service standards. In addition, we believe it is vital that momentum in infrastructure delivery is not lost by overhauling a recognised framework that delivers, and we encourage Ofgem to consider incremental changes to the framework where there is evidence it is needed.

We are supportive of a framework that looks at improving the visibility and accuracy of capacity and connection data, improving standards of service and ensuring contracted connection dates are met, however this needs to reflect the current landscape of significantly increased volumes and complexity of applications in addition to the current uncertainty as we implement the ambitious Connections Reform.

Specific issues that should be considered include:

- Realistic timescales – regulatory timescales have been unchanged for a number of years and do not recognise the volumes or complexity of applications we are now seeing. The framework needs to drive the right behaviours, focusing on quality not just quantity and fully recognise delivery issues in relation to, for example, a supply chain which is subject to increased competition and long lead times.
- Stakeholder surveys - whilst we understand the importance and consider such surveys as a valuable way to gather feedback to directly influence improvements, these should recognise areas that we have control over, and those that we do not. The new connections reform enduring proposals and Clean Power 2030 may influence feedback, especially when the national and government targets, and their implications, are not well understood or well received.
- Charging will continue to be a key consideration for connecting customers, and the current CAP action to review how Transmission works triggered by Distribution connecting customers is paid for is an example that will require clear direction from Ofgem, as was previously provided for the Access Significant Code Review.
- DNOs are best placed and need to have the ability to manage connections to the network in the most economic and efficient manner, by enabling more innovation, both technological and commercial and be supported by an appropriate regulatory framework. Whilst the Regional Energy Strategic Plan (RESP) will support co-ordinated development of the energy system, the decision framework for the RESP needs to be clear that it is the DNO who has the final say on design and connection compliance.

It is important that Ofgem fully consider the impact on the ED3 framework when proposing changes via the end-to-end consultation We welcome the opportunity to respond with more detail in Ofgem's end-to-end consultation.

Question 38. In the context of greater electrification, is our current approach towards regulating reliability appropriate for ED3?

The Interruption Incentive Scheme (IIS) has delivered a profound improvement in customer reliability since its introduction, with average CI/CML reducing from 80-90 in 2001, to 30-40 in 2023/24. Over this time DNOs have been rewarded for making these significant improvements, but over recent years the IIS scores have begun to stabilise, and in year 1 of ED2 DNOs are now in aggregate penalty of £30m. As a consequence of this stabilisation, we believe that a reappraisal of the effectiveness of IIS may now be appropriate.

Although this is not an unintended outcome for Ofgem, having set much tighter targets and an asymmetric incentive regime for ED2, it should be noted that DNOs strategies for network reliability improvement since ED1 have been self-funded. It is the return from the incentive that funds the reliability improvements, although avoiding penalty is a strong incentive, if there is no funding available to deliver the improvements – reliability improvements will stagnate.

In the context of decarbonisation and greater electrification, growing energy demand and the greatest level of network connections by GW ever experienced, it is vital the current IIS approach is re-visited in ED3 to ensure reliability incentives continue to be fit for purpose by stimulating reliability improvements.

A key requirement of this is to revisit the Value of Lost Load (VoLL). The VoLL was last subject to a major revision in around 2013, and it will be 15 years out of date by the end of ED2. Although it has been revised with inflation for ED2, this does not consider the wider societal, economic (micro and macro), or energy efficiency changes which have occurred in the intervening years. As customers transition to electric transport and heating, it is accepted that their dependency on electricity and the continuity/reliability of supply increases. As the UK economy seeks to grow domestically, with a greater level of domestic energy security, it is acknowledged that a readily available and highly reliable power system is a necessity. And as society transitions to an energy efficient, highly digital and hybrid workforce, the utility of a kWh is greater than ever before. All of these factors contribute towards the VoLL and a robust review of the underlying value, as well as how it varies over time e.g., the duration of an interruption, or regionally / by customer type e.g., for LCT owners, must now be considered.

We strongly support the review of the VoLL to ensure reliability incentives are properly geared, but also suggest that the output is delivered early in the ED3 planning process to allow it to be embedded in planning decisions and wider mechanisms, and in a simple way to ensure it can be adopted quickly within the wider price control framework.

In terms of the future of IIS, our view is that improved incentivisation would be a more effective approach in ED3, particularly with the stabilisation effect in ED2. We believe the wider interactivity of reliability measures should be considered holistically to determine the optimal future incentive regime; Unplanned and Planned CI/CML, Worst Served Customers, Guaranteed Standards of Performance (including lessons learned from recent storm events e.g. Arwen and Darragh), Exceptional Event Thresholds, Short Interruptions and Multiple Short Interruptions. Only by reviewing these elements holistically, can an adequate reliability regime be designed which creates credible opportunity for reward and threat of penalty, an expectation of realistic improvements in reliability and drives a better service for customers.

Question 39. What role should bespoke outputs and CVPs have in ED3?

We agree with the principle that bespoke outputs should be minimised to ensure that *“customers can expect a similar level of service regardless of location, company performance remains comparable, company focus remains on areas of high importance to customers, and to ensure the price control is efficient and manageable.”*

Whilst we do believe that there may be circumstances where local conditions might require a bespoke incentive, we also believe that potential ‘postcode lottery’ concerns could be addressed by Ofgem encouraging DNOs to work together on country-wide or regional bespoke incentives. This would benefit consumers as Ofgem would still reserve the right to accept or reject these, while stimulating collaboration and joined up thinking across the industry.

We do not believe that the Consumer Value Propositions should be adopted in ED3. They did not work well during the ED2 business planning process and became incredibly resource intensive and complex due to the lack of clarity around what Ofgem expected from these. The volume of CVPs submitted (24), compared to the number fully accepted with rewards (3), as set out by Ofgem, is evidence that the concept did not work in the form it took in ED2 and does not warrant Ofgem and DNO resource focus in ED3.

Question 40. How can we optimise late and early competition models for application in electricity distribution?

DNOs already face strong competition in connections from Independent Distribution Network Operators (IDNOs) and Independent Connection Providers (ICPs). We believe Ofgem should not lose sight of the level of competition which is already prevalent throughout the sector.

We do not think that early competition should be further considered for distribution projects. Projects at distribution level are significantly different in the scale, scope and nature to transmission networks and are typically delivered on shorter timescales, meaning any significant delay created by the Early Competition Model would have a greater impact on project timelines. The Early Competition Model could risk the timely delivery of distribution projects required to facilitate customer connections and achieve net zero. At a time when upgrading the distribution network at pace is critical both to ensuring households can decarbonise and, to maintaining the safe operation of the network.

Distribution projects are also typically of lower value, further limiting the benefit from running an extensive tender process. Competition models should only be implemented where long term consumer value is proven. There has also not been any analysis of the risks of introducing competition carried out in respect of distribution.

The consumer benefit of introducing competition has not yet been robustly demonstrated, even for higher value transmission schemes, however due to the substantial difference between distribution and transmission it would not be possible to rely on a transmission related assessment because the interactions with and implications for members of the public are substantially different at distribution level to that at a transmission level. Ofgem should focus on assessing whether such competition is likely to develop in a way that benefits consumers

instead of placing too much weight on whether a market is contestable. It is not necessarily the case that competition is appropriate in all sectors and scenarios; just because competition could be introduced into electricity distribution does not mean it should.

Question 41. How should our approach to cost assessment evolve, to enable us to better manage increasingly pronounced trade-offs between consumer protection, efficiency and investment in the distribution network?

The RIIO model, in our opinion, remains fit for purpose overall and has demonstrated the ability to evolve for changing circumstances like the increasing risks from climate change and current net zero targets. The efficiency incentive properties of the totex approach are a key foundation of the RIIO model and we are concerned that, unless properly assessed, changes to the cost assessment approach could undermine the efficiencies identified as a result of the Totex Incentive Mechanism.

Ofgem's benchmarking will however need to evolve to take account of the more complex nature of the price control, the more prominent use of uncertainty mechanisms and the role of stakeholders and new and emerging actors within the energy sector. Ofgem's cost assessment seeks to bring all DNOs' modelled cost allowances in line with a common decarbonisation scenario (System Transformation, from the "Future Energy Scenarios"). To do this in RIIO-ED2, Ofgem has used a "Demand Adjustment". The introduction of this demand adjustment, and the allocation methodology used at the final stages of the Cost Assessment processes was contested following the final determination of the RIIO-ED2 price control due to the impact of the allocation methodology used, which introduced misallocations of allowances within ex ante allowances which would be superseded by annual recalculations. In part, this impact was generated due to the disconnect between Distribution Future Energy Scenarios (DFES) used by the DNOs and the normalisation (Demand adjustment) applied to all DNOs totex to be able to undertake the benchmarking assessment.

Ofgem's approach in RIIO-ED2 allocated a larger allowance to the LRE category of costs than Ofgem's own modelling would suggest. The effect of this over-allocation to LRE came at the expense of other cost categories for which Ofgem set allowances lower than the modelling would suggest is required. This has no effect on overall allowed totex for the control period, but because allowances for LRE are updated during the period, DNO's overall totex allowance will be lower ex post. The error in isolation was calculated to be worth c£30m to c£48m to SPEN, with the methodology most aligned with Ofgem modelling placing the error at c£30m.

Since the RIIO-ED2 Final Determination, there have been further changes within the industry including the introduction and evolution of the Regional Strategic Energy Plan (RESP), and the development of the CP2030 Plan. If DNOs are to incorporate the RESP role, and to enable the plans to fully reflect and enable the delivery of the regional requirements of net zero and CP2030, including the interventions necessary on a regional basis, then this cannot be subject to standardised or normalised cost assessment or benchmarking at the conclusion of the price control process.

The RESP role also means that DNO Business Plans will have external assurance incorporated from a public authority embedded throughout and will be scoped and developed to meet their specific regional needs to achieve CP2030 and net zero. The risk is that the current approach to benchmarking of costs and volumes at the aggregate level would lead to the removal and or reduction in the interventions and investments which have been determined as necessary in the region. There therefore needs to be a recognition that the integrity of the plan must be maintained to ensure that the DNOs are able to deliver the programme required to support net zero as set out, and whilst benchmarking should still be applied, it should consider the project level and unit cost level of efficiency, as opposed to the top down modelling approach which simplifies the assessment down to the overarching scale of the DNO. Aligned to the above, the final post assessment benchmarking methodology must be fully discussed and agreed early in the business planning process as part of the development of the framework.

During ED2, there was at times a lack of clear visibility across the full suite of the benchmarking and assessment proposals, which meant that benchmarking outputs could not be fully discussed or tested prior to the draft and final submissions, and important stages in the benchmarking which had a material impact in the results were unable to be fully understood. This is also true of the post benchmarking allocation methodology. This is in part due to the complexity of the framework, and a recommendation as part of the RIIO-ED3 cost assessment modelling would be to review how this benchmarking correlates with the engineering and project specific assessments of the contract. For example, it is difficult to statistically assess Data and Digital investments when we are challenging DNOs to set out ambitions Data and Digital strategies, but these are then benchmarked on scale variables which do not currently recognise the complexity of the Strategy or the Digital infrastructure within each of the individual Network operators.

We believe that the programme of work should look to better utilise the existing processes and tools within the RIIO framework where lessons can be learned, and improvements made. Further, the use of the cost assessment methodology needs to agree how more bespoke costs are treated, to ensure that the specific needs of our stakeholders are not simply benchmarked and removed due to comparison with other regions or other DNOs not recognising the need. Specific DNOs may have bespoke, and stakeholder agreed initiatives, which are specifically aligned to the needs and requests of our stakeholder engagement activities, and during previous price controls we have seen costs removed through the benchmarking process which specifically aligned to the needs and requests of our stakeholder engagement activities.

Simplification and transparency of a cost assessment process is crucial to stakeholder acceptance. Cost assessment is a complex process and there is no 'one size fits all' approach, rather a range of models is likely to be required. Principles need to be established and agreed to apply relevant models e.g. a form of regression analysis for repeatable activities, benchmarking for discrete items, derivation of relevant cost factors etc. In each approach, however, limitations must be recognised; checks and balances may be necessary to ensure fair and reasonable outcomes for stakeholders. Cost efficiency principles should be clear and unambiguous; balanced against asset reliability and network resilience to ensure existing and future consumers receive value for money projects.

Regulatory treatment must recognise that in a portfolio contract like the price control - any cost assessment process must properly consider materiality and proportionality in its

application. In addition, although it is important to capture the right information for cost assessment, it is equally vital that such information is clear and unambiguous in its definition. The annual Regulatory Reporting Process (RRP) is fundamental to understanding whether the data and information captured therein is producing the right output for all stakeholders and the capture is at a proportionate level of detail. There is merit in undertaking annual benchmarking – learning from experience – and mutually agreeing changes to Regulatory Instructions and Guidance (RIGs) to address deficiencies e.g., data gaps or reporting inconsistencies to improve future regulatory understanding and ensure a proportionate level of reporting.

Question 42. How should our guidance for cost benefit analysis evolve to better enable optioneering between different interventions, taking relevant long-term risks and benefits into consideration?

We strongly advocate for early confidence in development of Cost Benefit Analysis (CBA) guidance and templates to ensure DNOs can develop ED3 engineering submissions consistently, and in a timely manner.

There are some key areas we believe should be considered for inclusion within the CBA guidance and templates, including:

- CNAIM Long Term Risk for NARMs assets.
- Improved application of wider risks, deliverability, climate and cyber etc.; Early Confidence in the application of Value of Lost Load (VoLL); and,
- Consistent assessment of Flexibility to defer network investment, including the full adoption of losses in lifecycle cost analysis.

Currently, CNAIM Long Term Risk is captured in memo format within the CBA template, embedding this within the CBA calculations would ensure that asset condition investment cases benefit from whole life risk and benefits. By standardizing this within the CBA template, it will ensure a consistent method across the DNOs, irrespective of the investment driver.

We would encourage further investigation of how CBAs could be expanded to capture a broader view of risks to give a greater overview of the benefits. This should include deliverability risks and contributions to network resilience such as climate and cyber risks. New resilience metrics should be considered for inclusion in the CBA template to help support investment decisions.

We note Ofgem have identified that some DNOs have assessed the benefits and drawbacks of flexibility differently within CBAs and agree this requires a more common approach. This should recognise that Flexibility to defer network investment is a bridging solution to longer term capacity upgrades. The disbenefits of ‘network constraint flexibility’ should also be considered i.e. where it may limit other flexibility use cases within the wider system, or where it delays future connections. We continue to see flexibility as an important tool to manage the scale and pace of increasing demand but believe a more holistic view of its risk is vital to deploying it in the right way.

CBA remains a key tool for optioneering and justifying projects. A simple and standard approach to the CBA guidance and templates will help ensure a more aligned CBA output across different DNO submissions and across projects with different intervention drivers.

Question 43. Do you agree that the current Real Price Effect (RPE) methodology should form the basis for adjusting allowances in ED3?

We agree, in principle, that RPEs and ongoing efficiency have an enduring role to play in price controls. RPEs do, however, need to be reviewed to ensure they are fit for purpose and operate in a fair and reasonable manner.

In the case of RPEs, this needs to be considered against a backdrop of supply chain price escalation and volatility. They do need to better reflect the cost drivers behind market cost volatility (e.g. commodity prices such as steel, copper, etc) so that they operate in a fair and reasonable manner.

While the methodology underpinning Ofgem's RPE indexation mechanism is well-understood, there are material concerns regarding Ofgem's application of this methodology.

There should be specific consideration and regular evaluation of whether indices that are utilised to set expected RPEs reasonably reflect DNOs' genuine cost pressures. If representative indices are not reflective of real input cost movements that DNOs face, nor granular enough to capture true nuances in cost changes, then there is the risk that the RPE framework will fail to protect companies and consumers from input price pressures, and companies will remain excessively exposed to input price risk.

Question 44. Do you agree that the current approach to setting the ongoing efficiency challenge is a suitable starting point for ED3?

The situation with ongoing efficiency is similar to RPEs and suitable comparators against which DNOs can be measured need to be determined. We are happy to support further development in this area to ensure that existing and future UK consumers receive value for money across projects being delivered for net zero and network resilience.

The following should be considered (amongst others):

- The productivity metric being used as a proxy for efficiency, for example a relevant industry for the different parts of electricity distribution.
- The time period used for averaging – such that it is reasonable that productivity levels could be projected forward.
- The extent to which ongoing efficiency should be applied (such that OE is applied to relevant parts of the business that do not already have efficiency embedded into for example contracts).
- The aggregation approach being applied – whether or not a value added, or gross output approach should be used.

This should be considered in order to ensure that the estimate of ongoing efficiency is as accurate and reflective of feasible efficiency as possible.

Question 45. Do you see any reason why we should not implement the proposed changes to the calculation allowed returns, consideration of investability and assessment of financeability that we set out in RIIO-3 Sector Specific Methodology Decision – Finance Annex for ET, GT and GD?

We support the inclusion of an investability assessment alongside the existing financeability assessment. The concept of investability should continue to be developed and refined to build a comprehensive account of the real-world implications of retaining and attracting new investment. This can adequately inform adjustments to the allowed equity return, inform Ofgem policy, and assess new and current additional allowances, assumptions, and mechanisms, using both market and non-market-based evidence.

Ofgem has acknowledged that market evidence around investability is difficult to gather at this stage and is continuing to evolve. A test for investability should include both qualitative and quantitative metrics that represent the ability of the notional company to address funding challenges which are not captured in the current cost of capital estimates and financeability assessments. This test should include:

- Sufficient allowance for equity issuance costs, both direct and indirect.
- Attractive dividend yields.
- Strong and stable credit ratings and consistent cash and valuation metrics, including EV / EBITDA and Net Debt / EBITDA.
- A strong balance sheet with substantial financial flexibility to absorb shocks and manage capital requirements.
- A level of accounting earnings growth that substantially reflects asset growth.
- Investors maintain a view of regulation that is clear and predictable.
- Ease of capital deployment, low practical barriers to invest.

New equity capital can only be attracted if the level of return on offer is competitive compared to other competing opportunities in the wider market; and it is rational to prefer risky equity investment over safer debt investment given the wedge between allowed return on debt and allowed return on equity.

Ofgem cannot allow underinvestment in the UK to continue and needs to do whatever is necessary to incentivise investment to counter investor sentiment of an uninvestable market, due to low confidence over the connections of generation, perceptions of an unfavourable regulatory regime and better returns available elsewhere. Particularly in the context of the investment needed to achieve net zero.

Financeability does need to be wider in scope and should go much further than a piece of analysis toward the end of the price control planning process. There are four things Ofgem should consider in a wider financeability assessment:

1. The financeability assessment should cover both debt and equity. As Ofgem have recognised for RIIO-3 and beyond, there is a step change in the requirement for new equity investment, alongside a greater competition for capital in global regulated infrastructure. This is expanded on further below when considering the concept of investability.

2. When being benchmarked against the notional company, Ofgem need to ensure the notional company is a realistic benchmark for an efficient company. Any errors in the calculation of efficient costs and revenue allowances for the notional company will directly impact the expected level of equity return, and damage confidence in financeability from an equity perspective. While Ofgem will be ensuring the targets are tough, it equally needs to ensure the notional company assumptions are not too challenging as to be an achievable benchmark. Assessing financeability using inappropriately low-cost estimates will give an unrealistically optimistic view of the notional company's financial position. Taking a rigorous approach to the estimation of efficient costs is therefore vital to ensuring financeability is accurately assessed. Part of this includes considering the balance of risk for ED3 when it comes to Ofgem's duties where true efficient costs are different to Ofgem's best estimate. Further thoughts on the level of risk in ED3 are addressed below.
3. A financeability assessment needs to consider the longer term in which companies commit their investments. The investments we make, accumulated via the RAV, represent a commitment across price controls for which Ofgem needs to ensure the assessment covers the length of our investment commitment.
4. Cashflow considerations, which would require equity injections targeted towards closing gearing to equal notional gearing target, for consistency with the allowed rate of return, and optimal consideration for material changes in RAV, especially when there is significant upward movement in investment value.

Question 46. Do you see any reason why we should not implement the proposed updates to financial resilience requirements that we set out in RIIO-3 Sector Specific Methodology Decision – Finance Annex for ET, GT and GD?

We understand and fully support the requirement to ensure public interest entities of critical national importance have financial resilience standards.

Below we have set out our thoughts on each of the additional financial resilience measures under consideration:

1. Proposed measure 1 (requiring maintenance of more than one investment grade rating): The removal of the 'reasonable endeavours' qualifier leads to a requirement to maintain investment grade in any scenario, no matter what the cost or wider implications or face a licence breach. This represents a step up in strength of the obligation. Ofgem needs to consider this change in obligation very carefully and ensure our financeability targets and funding arrangements cover us for this increased obligation, should it deem a heightened obligation appropriate. Further, the obligation to maintain two investment grade credit ratings can prove particularly difficult under the scenario where one credit rating agency takes a significantly different view of a sector or company from another agency. This requirement could lead to suboptimal decisions to maintain two investment grade ratings, i.e., equity calls to appease one agency with the toughest ratings criteria/credit assessment. The inefficient consequences of this additional risk

could ultimately lead to either additional returns being required from equity holders or companies urgently needing to find another credit rating agency with different views on the prospects of the company/sector.

Further, the expanded requirement to maintain two credit ratings introduces additional cost to the business. These additional costs manifest themselves in both management time, explaining the company strategy, prospects as well as input into the agency's sector publications, but also in development and maintenance of a strong relationship between the company and the respective rating agency. Over and above the management time are the ongoing fees/expenses involved in maintain two/dual credit ratings.

The scenario of split dual ratings can also have negative impacts on access to capital markets and/or pricing when accessing those markets. Another potential question/issue with respect to split ratings would be if it is the lower of or higher of rating that would trigger regulatory events/involvement. The best way to maintain the relationship with the credit rating agencies is consistency of delivery of results that were forecasted/expected. That key requirement means a stable and supportive regulatory regime. There are only a handful of rating agencies that are universally recognised by the wider financial investment community. If these agencies understand that companies will be forced to use two of them then this could lead to a lower competition and higher prices for those ratings.

2. Proposed measure 2 (amending the dividend lock-up trigger): We largely agree with the principle of this measure, however it is important to clarify here that this measure could only be acceptable if Ofgem ensure that financeability targets are not reduced or diluted to ensure we can maintain sufficient headroom to avoid BBB- with a negative outlook. The importance of maintaining current financeability targets is set out below.

Targeting a lower ratio would impact funding availability and cost. Although a lower ratio may still be investment grade, a lower ratio implies greater risk and therefore may reduce the appetite of debt investors (reducing the funding pool) or require an increased return on the debt which in turn would increase the ultimate cost to the customer. The current target ratio also provides a buffer, to absorb any market shocks that potentially result in a downgrade that would more quickly trigger reaching BBB-lockup scenario.

Ofgem should set out clearly how this measure may be applied and work in practise. The concept of amending the dividend lock-up trigger to be the earlier of reaching BBB- with a negative watch/outlook and 80% regulatory gearing adds more complexity. The rating agencies closely monitor financial ratios, specifically gearing ratios in forming their credit opinion and view on rating and outlook. Using a credit metric brings into question the frequency of assessment and timing given a measure at one point in time can be impacted by short term market shocks that wouldn't be factored into the rating agency's longer-term view. The rating agencies are quick to respond and adjust ratings where appropriate but also avoid knee-jerk reactions that create volatility in ratings.

3. Proposed measure 3 (amending the Availability of Resources requirement for board certification to cover the entire price control period or at least three years ahead): We don't believe this proposed measure is necessary and believe the current availability of

resources requirements have not been shown to be insufficient. This measure places significantly greater responsibility on licensee directors than is the case under the current company law requirements.

The requirement for Board Certification to confirm sufficient financial resource to cover a minimum term of 3 to 5 years is asking Directors to go above and beyond the existing going concern requirements, under UK Law, of sufficient liquidity to cover 12 months post the date of signing financial accounts.

Providing this level of comfort would require substantial long term committed facilities, which bear additional cost, and depending on the applicable assumptions could have a detrimental impact on the ability to implement a flexible treasury funding policy, take advantage of favourable market pricing and manage financial resource across the wider group. This could in turn lead to an inefficient increase in costs for consumers.

If Ofgem was to decide to amend the Availability of Resources requirements in the manner described, it needs to set out realistic assumptions for how the 5-year requirement is funded and ensure these are consistent and agreed. Ofgem should be clear whether Ofgem assumptions should be used, or companies' own assumptions which Ofgem will agree and scrutinise if needed.

Question 47. What are the key factors (including benefits and costs to consumers) that Ofgem should take into consideration when conducting its review of the appropriate approach to regulatory depreciation in ED3 and beyond?

There are a number of key perspectives that should be considered, when reviewing/adjusting depreciation policy in upcoming regulatory periods:

- Intergenerational fairness: Ofgem should consider the consequences of different depreciation policies/asset lives over the life of assets, e.g. the question of who pays and who benefits? This should also add to the emphasis on asset lives having some reflection of true useful lives.
- Depreciation method: Consideration of Sum-up the year digit (SOYD) with reduction in asset lives should be considered. Alternatively, a reducing balance method should be considered while asset lives can either be reduced or held at 45 years.
- Financeability perspectives: Under-recovery of assets has a negative impact on returns and a compounding effect on the FFO's consideration of short and long-term financeability. For example, credit ratings resulting from adjustments to depreciation, and whether this maintains an investment grade credit rating.
- Investability perspectives: Ensuring that companies are financeable whilst ensuring that levels do not mean there is a significant mismatch between generations. There should also be a consideration as to the size of RAV itself and how the new RAV is recovered over the subsequent periods.

To avoid repetition, we have not replicated the content we contributed to within the ENA's response to this consultation question.

Smarter Networks

Question 48. How should the price control encourage ongoing development of the DSO role and activities to optimise whole system benefits for existing and future consumers?

Our response to question 49 explains the roles and activities we think the DSO should have in ED3, and where the DSO has a responsibility to whole system benefits. The price control should encourage the ongoing development of these DSO roles and activities in the following ways:

- **ED3 Business Plan guidance:** the roles, activities, and baseline expectations should be set in the ED3 Business Plan guidance (as was the case for ED2). These should be developed with stakeholders and DNOs. Having the roles and responsibilities of DSO defined in business plan guidance provides clear common guidance that business plans can be developed to deliver. It helps ensure a more common DSO model, which is valuable for customers and for the NESO who need to interact with multiple DSOs.
- **DSO incentive:** we support the continuation of a DSO incentive, to ensure that DSO deliverables are delivered on time. Stakeholder opinion should continue to be an important part of this, as they likely have a perspective of working with multiple DSOs. This incentive is likely to need to evolve as we go into ED3 to recognise the evolving role (explained in question 49) of the NESO, RESP, and changing use of flexibility for wider system balancing.
- **Regulatory funding model:** there could be clear targets for the delivery of some discrete components (e.g. monitors to increase LV network visibility. Data is a key part of DSO – please see our response to question 50.

Question 49. What should the role of the DSOs be in identifying and delivering whole system benefits?

We think the value of having a DSO function will continue in ED3, although some of its activities will change their emphasis compared with ED2. We set out our view of the key activities for DSO in ED3.

- **Connections:** During ED2 there has been increasing DSO focus on enabling curtailable connections and ensuring fair network access. For ED3, there should be a strong emphasis on accelerating connections to achieve CP2030 as these have whole system benefits.
- **Network Operations:** The DSO should continue to support real-time coordination with the NESO to ensure operational optimisation and whole system benefits. For ED3, this should include safely enabling the NESO to utilise an increasing volume of DER flexibility for wider network balancing.
- **Market Development:** The DSO should continue to develop competitive DER markets and manage dispatch and settlement infrastructure. For ED3, this should have an emphasis on enabling DER flexibility for wider network balancing so the whole system benefits of using DER flexibility to balance renewable generation can be realised.

- **Network Visibility:** Increasing network visibility on LV networks will continue to be beneficial, so for ED3 the DSO should continue to enhance network visibility and utilise and share the resulting data.
- **Network Planning and Forecasting:** For ED3, the DSO should continue to enhance forecasting and network planning through local stakeholder engagement, working closely with the NESO and stakeholders to facilitate the customer requirements for their areas. This includes working with Local Authorities as they develop the Local Area Energy Plans/LHEES.
- **Data and transparency:** For ED3, the DSO should continue to enhance their provision of open data that can be dynamically interacted with by customers and stakeholders.

The role of the DSO will continue to evolve as networks accommodate decarbonisation, and as role of the NESO and RESP also evolve. The role of the DSO incentive within the ED2 period may also require further consideration to ensure a smooth transition toward ED3.

Question 50. Our historic approach to publishing and sharing datasets has been stakeholder-led and focused on establishing good digital foundations in the DNOs. With the rapid pace needed for enhanced data and digitalisation, should we instead be considering incentives around strategic priorities, such as network planning, flexibility, and connections?

In ED2 we have significantly advanced our compliance maturity with Ofgem’s Data Best Practice, enabled through the establishment of Data Governance into our organisation. Data Governance also plays a crucial role in ensuring that high quality data is available for our stakeholders by integrating technology, processes, and people, we have created a robust framework that supports data sharing and enhances decision-making.

The data we publish on our Open Data Portal is driven by active engagement with our stakeholders and aligns with Ofgem’s requirements, as outlined in their Open Letter on Operational Data Sharing, Smart Optimisation Output, DSO incentive, and Data Best Practice Guidance, amongst others. Whilst we recognise that these Ofgem requirements have advanced data products within the industry and contributed to the development of industry-wide interoperable datasets, such as LTDS and aggregated Smart Meter data, we believe that the frameworks have not fully ensured collaboration to prioritise and deliver interoperable datasets. Instead, the frameworks have placed a greater focus on simply having data available rather than data delivered to standards and formats which they should meet, leading to inconsistent outcomes for stakeholders. As we move towards the DSI, having data foundations in place will be critical for the timely delivery of data products internally and across the industry.

Another challenge has been in the triage of data, the risk appetite of network operators is different in some cases and there are examples of potentially sensitive data being shared under an Open Data licence with others (including SPEN) deeming these to only be appropriate to share under a Shared Data licence. In this regard, closer alignment is required between network operators and Ofgem, and solutions will need to be adapted in future to allow more granular controls for access to data to ensure it can be shared whilst managing data security risks.

We continue to develop the readiness of our data by considering CP2030, CAP, DSI etc. but ask for clarity on the roadmap for strategic priorities and data requirements – SPEN consider an objective driven approach with clear specifications of data requirements will increase alignment between Network Operators. To meet this need, we believe there could be a benefit to have an Energy Data Coordinator role with the mission to continue and extend industry wide stakeholder engagement, prioritise requirements, coordinate interoperability, take ownership of delivery of industry wide data programmes and continually measure outputs.

With respect to the DSI, SPEN are supportive of the developments and responded to Ofgem’s prior DSI Governance consultation. We consider further emphasis on building a clear roadmap for the development of DSI use cases, this will allow Network Operators to maximise their preparedness in underlying data.

Question 51. How can we enable greater development of internal digital expertise in its licensees?

We have recent experience in developing our internal digital expertise having scaled our delivery capability from ED1 to ED2 with significant success so far, as detailed in our ongoing Digital Strategy and Action Plan updates¹⁵. We believe that in the ED3 price control there is a need to continue to invest in upscaling DNO digital expertise, both in terms of people and technological capabilities as these are an enabler for growth in the Energy Sector to meet its future aspirations.

One of the main challenges for DNOs in developing Digital Expertise is that there is considerable uncertainty in forecasting the areas in which specific technological advances will be made. The pace at which new IT technology is developed and comes to market is not necessarily compatible with price control timelines and business plan development. For example, when drafting the business plan for the ED2 price control, we could not predict the rise of generative AI and as such we do not have investment plans to use this technology within the ED2 period to benefit customers.

We would welcome a review of possible mechanics within the Price Control framework that could allow for a more agile approach to the definition of IT and Data technology investments within the overall governance structure of the Price Control period. We ask Ofgem to recognise that while the initial few years of digital investment can continue to be forecast within the existing framework for Data and Digitalisation, later years in the price control have much greater uncertainty.

For these later years we would welcome further consultation on options that could allow for a more flexible framework for data and digitalisation investments. We believe this would allow DNOs to act with greater agility in adapting the digitalisation of our businesses to take best advantage of emerging and maturing technologies. We continue advocate that all investment in data and digitalisation be fully transparent with both the regulator and wider stakeholders.

We fully support the value in developing our capabilities to share data effectively and efficiently across the wider energy sector. We also agree with Ofgem that specific investment is needed

¹⁵ [SP Energy Networks – Digital Action Plan Update \(December 2024\) & Digitalisation Update \(March 2023\)](#)

to facilitate the interoperability of data between network operators due to differences in internal digital architecture and data models. Investment is needed to implement standardisation, which is a prerequisite of enabling effective data sharing. Fostering collaboration between DNOs should also continue while reviewing behaviours that impede collaboration as identified in our response to question 50.

Investment in our people is an essential part of any growth of Digital Expertise, this includes the ability to attract a digitally literate workforce, as well as allowing for the continuous development of digital skills of our existing workforce by ensuring sufficient baseline allowance is provided to train and develop staff. We cover this in more details in question 62 in this consultation response.

Question 52. How should network companies use AI to improve network insight and decision-making (both operating expenditure (opex) and capital expenditure (capex)) and how should we be encouraging this through the ED3 framework?

We agree with Ofgem that there are a variety of valid use cases for AI/Machine Learning that can improve planning, management and real time operations of the energy system. Effective use cases will become more apparent as DNOs trial solutions. We welcome engagement from Ofgem on this and propose the ENA's Data and Digital Steering Group (DDSG) as a suitable forum for this.

While emerging AI technologies are valuable, we must balance these with human oversight to maintain ethical standards, especially in high-risk or business-critical situations. Human intervention remains essential to ensure decisions align with our commitment to responsible AI practices.

We strongly believe in the responsible use of AI, and we align with the OECD Council's recommendation on Artificial Intelligence through the Iberdrola Group Policy on the Responsible Development and Use of Artificial Intelligence Tools. The newly developed AI governance framework at ScottishPower has introduced new roles and responsibilities to the workforce, underscoring the company's commitment to developing our people in emerging technologies and ethical AI practices – it is critical that we garner support for building this workforce including these new roles.

We agree that there are potential risks with the use of AI/ML and support Ofgem's work in developing guidelines for the use of AI in the energy sector, but that DNOs should be allowed to use AI/ML responsibly and should be able to evidence they have the right processes in place to manage AI risks to provide comfort to the regulator.

Possible ways Ofgem could encourage the responsible use of AI could be through the aforementioned AI guidance, by encouraging collaboration between DNOs, by allowing potential sandbox projects if AI/ML use cases might need a temporary derogation from licence conditions or codes, and by ensuring sufficient baseline allowance is provided to train and develop staff in the use of AI.

We have been assessing the landscape in technologies and opportunities and foresee further opportunities in:

- Using our newly developed data (LV Monitoring and Aggregated Smart Meter Data) with whole system data. Machine learning brings the potential to reduce uncertainty in system planning through introducing modelled whole system dynamics (digital twinning) improving the accuracy of our long-term demand and generation forecasting. This is expected to result in refinements in the prioritising of reinforcements by better understanding system constraints and solutions.
- Introducing improved demand and generation forecasts at secondary substation level to enable an additional option of using short term markets for managing constraints.
- Improving on our current use for short term fault identification, through the use of predictive maintenance could move from time-based to condition-based inspection and maintenance – the use of ML is critical in improving the longer-term network asset risk management.
- Whilst processes that require engineering and technical input are unsuitable for emerging AI and even Agentic AI technologies, there may be opportunities in developing more optimal customer interactions through the use of AI.
- Computer vision techniques are expected to be more widely applied making efficiencies in inspection processes.

We will continue to develop our innovation projects and assess opportunities to introduce these as business as usual – these include Predict4Resilience among others.

Question 53. Our aim is for the ED3 framework to be structured to deliver high impact, transformative innovation – do you think that further changes, alongside those proposed for the other sectors in our RIIO-3 SSMD, are required to deliver this?

We are broadly supportive of the positions Ofgem has taken in the RIIO-3 SSMD on innovation. We believe they contain most aspects required to deliver high impact, transformative innovation.

In addition to those, we would suggest that Ofgem consider exploring a greater incentive to encourage collaboration between DNOs. This could take the shape of additional NIA allowances for collaborative projects with other DNOs, in recognition of the increased time and effort required in securing the approval and adoption of DNO collaboration projects.

We are encouraged by the recognition in the RIIO-3 SSMD that not all innovation projects will lead to a deployable solution or technology, and that value also arises from sharing knowledge and learning, including of things that did not work. This understanding will help increase delivery of transformative innovation.

We do however believe that more could be done to reinforce that message. We perceive there is still a common impression amongst DNOs that stimulus-funded innovation projects are only successful if the desired outcomes (e.g. an anticipated benefits) are achieved. This can lead to DNOs being reluctant to pursue the more novel and potentially transformative innovations and instead opting for lower-risk innovations, which carry a higher chance of success, but less potential for benefit. We believe that, in order to counter this phenomenon and encourage more transformational innovation, Ofgem could provide clearer signals of its expectations; for

example, by recognising within the framework that for every innovation project that results in the forecast benefits being realised, there are likely to be at least another 'X' that do not.

Question 54. Are there any factors particular to DNOs that facilitate or challenge deployment of innovation on their own and across networks?

We believe there are two areas of particular challenge that are worth drawing out and for Ofgem to consider potential mitigating measures:

- Innovation is an area where competition and collaboration are often at odds. DNOs compete to access SIF allowances or to be the first to pioneer projects but are at the same time expected to collaborate closely and share results. DNOs therefore have an implicit reputational incentive to overpromote their own innovation projects while downplaying those of other DNOs. Although results of innovation projects are published, we believe more could be done to improve cross-DNO adoption and engagement. As briefly alluded to in our response to question 53, there may be space for Ofgem to consider how DNOs could be incentivised to engage in multi-DNO collaboration projects, and for funding to be made available for the implementation of successful innovation projects by other DNOs.
- Both TOs and DNOs have strong health and safety obligations and Electricity Act duties to provide a safe, secure, reliable and efficient supply of electricity, which need to be satisfied across a large range of assets. However, DNOs own and operate more assets than TOs do, with a much greater proportion of those being located in the public domain or in customer homes. For the DNO then, these duties need to be satisfied across a larger range of assets. Introducing an innovation can create a sense of jeopardy to these core duties, and it is important that new solutions are implemented in a measured and careful manner to avoid unintended consequences. In addition to our core duties, DNOs are also subject to a stricter regime of customer facing incentives than TO's, and these can carry significant financial consequence if an ultimately detrimental change is pursued. Ofgem may wish to consider how they can encourage DNOs to deploy innovation in a protected way, for example by protecting DNOs in certain incentives, and setting timely expectations for deployment recognising the above concerns.

Resilient and sustainable networks

Question 55. Do you agree that we should retain the Network Asset Risk Metric (NARM)? How should it further evolve in ED3?

We strongly agree that the Network Asset Risk Metric (NARM) should be retained.

The electricity distribution sector has the most advanced and consistently adopted approach of all regulated market segments. DNOs have collectively worked with Ofgem to establish and develop the Common Network Asset Indices Methodology (CNAIM) as the basis for the NARM and we continue to collaboratively develop this methodology for ED3. This ongoing refinement

and continuous improvement ensure CNAIM accurately reflects asset risk and supports our asset management practices.

Our position is in line with the NARMs Electricity Distribution Working Group (NEDWG) approach to continue the evolution and expansion of NARM through:

- Supporting Ofgem’s aspiration to increase the number of NARM assets where a valid CNAIM model can be developed and agreed with all other DNOs through NEDWG. It should be noted that this includes ensuring risk fungibility for new assets, updating RIGs where required and ensuring accurate, timely and complete asset datasets. We support creating a ‘sandbox CNAIM’ for asset categories where data and condition metrics are less established, to avoid undermining the integrity and value of the existing NARM methodology.
- Enhancements to current CNAIM models (where appropriate) based on developing evidence of asset condition factors and their impact on overall deterioration.
- Continual development of NARM/CNAIM guidance, such as DNO Good Practice Guides, to aid in a consistently applied approach to model condition inputs.

We believe that the current approach of NARM targets and deadband is suitable for asset health investment. However, as emerging risks that affect probability and criticality of failure become more prevalent e.g., through the changing climate, we believe increased flexibility within the target methodology and deadband range will be required to allow greater reprioritisation/variation within programmes.

Question 56. Do you agree that we should consider a more integrated approach to managing asset health, together with load-driven expenditure, given the need to future proof for resilience (climate, cyber and physical security) and future demand? What might the risks and benefits of this approach be?

We agree that there is merit to holistically considering:

- Asset Modernisation (NARM and Non-NARM),
- Network Resilience, and
- Load Related activities.

This is the approach we took for ED2 planning within an output orientated framework.

These are the 3 primary investment drivers that govern DNO proactive intervention plans. However, we ask Ofgem to note that there are significant differences in the drivers for these works e.g. capacity, reliability/risk, and security & continuity. We believe that these differences are the underlying reason these areas are split and scaffolded by differing regulatory mechanisms; outputs, incentives, reopeners, and monitoring/reporting requirements.

We do not believe that integrating asset health and load within the same mechanism regime is necessary to ensure that load and asset health investments are co-ordinated, but that clearer expectations can be set in each area to ensure adequate standards are provided regardless of the intervention driver e.g. provision of net zero capacity or climate-proof investments.

Non-Load (NARM, Non-NARM and Network Resilience) activities are planned at the start of a price control period, but due to changing levels of deterioration, collection of latest available condition information, updates to engineering standards or changes in national resiliency requirements – these plans often change during the period. The sophistication of NARM is such that it allows for flexibility, fungibility and versatility to respond to these changes whilst ensuring DNOs performance is held to a target.

We do not believe that a prescriptive input-style approach would be helpful for asset health investments and would reduce the ability of the company to respond to changes in external factors or respond to latest network condition information. Our view is that this would sterilise the Asset Management functionality of the company and allow emerging risks to propagate unchecked until the next price control cycle.

Instead, we advocate that modernisation plans should be developed with load, asset/network risk and resilience in mind to ensure DNOs deliver a safe and secure supply to customers. Plans should be supported by engineering justification and cost benefit analysis, to ensure the most appropriate and cost-effective intervention is selected following a ‘touch it once’ approach. For instance, we believe that asset modernisation can be co-ordinated with both the RESP and DFES to accommodate future load demand for the asset lifespan to avoid early life replacement and reinforcement without being input orientated.

Separately, as the NARM benefit of load expenditure is reported in the RRP each year, business plan submissions could be extended to include a memo of the incidental NARM output for load.

As mentioned in our response to question 55, the CNAIM methodology is continuously under review to ensure the calculated asset risk accurately reflects the latest understanding of asset deterioration and the factors that influence it. This means ensuring factors relating to load, climate (severe weather or micro-climates) and expected life related to asset specification and operating conditions are reviewed and updated where required. NARM already holistically evaluates risk through inclusion of load (network loading and customers affects asset criticality) and options to ensure that climate change is being considered. We are actively involved in continuously developing NARM to integrate complimentary factors (load and resilience related) to the condition and consequence factors.

We believe that there is a risk that expanding NARM to include resilience factors without robust evidence could discredit the existing NARM mechanism. However, there is an overarching benefit of a single mechanism to benchmark DNO modernisation plans.

Our preferred approach is to continue to build the evidence base for integrating such factors into an adapted NARM mechanism throughout ED3, to further develop NARM for ED4. There are significant lead times in developing new asset models and ensuring they are robust for all DNOs to report against, which must be taken into account when expanding the methodology (e.g. work to develop CNAIM for ED3 started in Year 2 of ED2).

Question 57. In the context of making anticipatory investment decisions, what do network companies and other stakeholders need to enable the planning and delivery of cost-effective network resilience measures against our changing climate? What risks and opportunities do you see linked to an input-based approach to these investment plans?

We welcome that for ED3 Ofgem are considering whether the tipping point in the balance of risk between load related expenditure creating capacity too early is now outweighed by the risk of the capacity not being available when it is required. We believe that enabling society to decarbonise and to achieve net zero will only be possible through proactive anticipatory investment, where although there remains some uncertainty about the exact load requirements, the risk of capacity not being available is too great.

We are facing the same challenge with respect to climate change. Although all projections point to rising temperatures, increased precipitation, and harsher severe weather events the timing, frequency and severity of these changes are unclear. However, we can neither afford to wait until we have felt the impact, or to delay works until there is insufficient time and resource to avoid the consequences. As such, ED3 is the time at which the scale of uncertainty must tip in favour of 'climate-proofing' investments.

Climate change impacts over an asset's life should be accounted for through design wherever possible, including impacts that may only materialise later. These decisions should be made alongside future demand and load projections to ensure that the most cost-effective interventions are deployed. We believe there is little benefit in avoiding an intervention for the purposes of network capacity if a repeat intervention is required anyway to mitigate against climate change.

To enable the planning and delivery of a cost-effective network we wish to highlight that network companies need the following support mechanisms to be able to undertake Climate Resilience investment:

- Confidence and adequate provision of regulatory allowances, underpinned by well-structured benchmarking that does not penalise or reject allowances for holistic/incremental investment.
- Agreed baseline climate projections, or a range of projections which DNOs can plan against, including a Climate Change Resilience Metric (or similar) to govern delivery. This includes an assessment of the risks to network companies and their assets, plus consequential effects to customers and other stakeholders. This approach is under initial development and continual improvement through the ENA climate change resilience working group.
- Recognition that geography, network topography and local features will have a significant impact on required works, and a one-size-fits-all method will not work.
- To ensure resilience across UK infrastructure cascading 'whole system' interdependencies of climate change should also be considered. Investment decisions need to consider how consequential effects will impact other infrastructure/customers e.g., increased air conditioning demand for hospitals/key customers, or substation flooding impacting telecommunications masts.

- Support for anticipatory / tipping point investment – acknowledging that whole-life solutions will reduce overall costs within Cost Benefit Analysis.

We also wish to highlight that although there may be a perception that a prescriptive input-based approach would ensure DNOs deliver a consistent approach to investment planning, the underlying uncertainty in climate forecasts would be effectively amplified. We believe this is a risk as the principle/output-based approach within the current ED2 regulatory framework allows uncertainty to be mitigated by the varying approaches and programmes DNOs take to deliver investment plans.

While it is still possible to set clear output expectations despite this uncertainty (i.e. Flood Resilience and Severe Weather Resilience standards are set out in ETR 138 and ETR 132 respectively), without overly constraining the types of intervention that are employed. For uncertain climate resilience investment to be considered in the same way as previous output-based network resilience programmes, DNOs would need to ensure that multiple pathways and interventions have been reviewed before selecting the most appropriate and cost-effective solution.

Question 58. How should we monitor progress on the delivery of climate change resilience? Do you have any specific learnings which can help shape this?

We have been actively involved in the ENA Climate Change Resilience Working Group, leading on the development of the heads of terms for a climate resilience metric and drafting guidance to be reviewed and adopted by the ENA. We believe a Climate Change Resilience Metric would allow quantification of progress in delivering climate change resilience, with several options for how to monitor this.

We believe that potential methods in order of decreasing complexity and sophistication are:

1. An approach similar to the current NARM methodology, setting a starting climate risk position and developing a target end position to achieve through delivering specific climate resilience activities.
2. An incentive or performance-based mechanism, measuring improvements against named climate risks such as number of weather-related failures. This would be complicated, as it would require normalisation against local climate risks for each licence area.
3. An output or input based mechanism monitoring compliance with pre-existing resilience standards such as ETR 132 (Improving resilience of overhead networks under storm conditions), and ETR 138 (Resilience to Flooding of Grid and Primary Substations).

There are challenges and benefits of each of these approaches. Setting a definitive target or performance incentive is difficult due to the uncertainty of climate change impact and irregular nature of weather, creating the risk of windfall penalties or gains. Given the uncertainty the measure should recognise the scale of work completed, rather than the performance against as yet unknown impacts.

A potential mechanism must also consider the regional and network differences between DNOs, acknowledging that some networks face different types or scales of risks. Within SPEN, SPD and SPM face different types, growth rates and volumes of vegetation, affecting current tree-cutting regimes.

We are supportive of Ofgem's ongoing engagement and commitment to the Climate Change Resilience Working Group and agree this is the best forum for ongoing development work. This group should feed into the methodology development and alongside key industry experts.

We anticipate this approach will be reviewed again for ED4, recognising that despite ED2 introducing the Climate Resilience Strategy, this remains a nascent and emerging area. However, we encourage a bold approach to ED3 to ensure there is adequate funding provision and confidence for network operators to ramp up resilience efforts.

Question 59. Do you have any comments on the suitability of current incentives to ensure that consumers continue to receive a reliable service in the face of climate hazards?

Reliability incentives ensure our customers receive a dependable supply throughout the year, despite unforeseen network faults. Ofgem already incentivises reliability through the Interruptions Incentive Scheme (IIS) and the Guaranteed Standards of Performance (GSOP), while the Broader Measure of Customer Service (BMCS) incentive is influenced by network reliability and resilience at a second order level, pending input from forthcoming UK Government climate resilience standards.

Reliability incentives monitor the number and duration of interruptions and apply minimum expectations about restoration times. Different rules apply for exceptional events e.g., where abnormally high fault rates arising from severe weather are excluded from the IIS incentive. We believe that incentives which protect the day-to-day reliability of customers supplies have been successful and although in need of redesign/refreshing for ED3, have potential to remain a useful and relevant tool to ensure a reliable service.

However, there is currently no direct incentive mechanism for resilience, i.e. a reward/penalty to measure the ability to avoid or recover from extreme (or even routine) incidents which may or may not be subject to the IIS, GSOP or BMCS. In the event of climate resilience, this could apply to both banal changes, such as the increased requirement for vegetation management as growth rates continue to increase, or to extreme climatic events such as major storms or floods. As with all gradual and macro changes, climate change is not seen as a paradigm shift when we feel the effects at a regional (micro) level. It is only in looking at the overarching data that the increased flood, storm and gale events become apparent. As such, incentives in this area cannot only be employed under scenarios which are extreme against a recent timeline but must capture all weather events above a pre-determined baseline e.g., 1990-levels.

We believe a wider climate and resilience incentive should be explored for ED3 to improve DNO abilities to withstand, respond and recover from climate events, especially as reliance on electricity grows with net zero forecasts showing greater customer demand. The climate resilience metric under development by the Climate Change Resilience Working Group could be one part of this.

Question 60. Do stakeholders agree with retaining and strengthening the main components of the environmental framework from RIIO-ED2?

The environmental framework set out in ED2 provides a robust mechanism for DNOs to report on their performance through the ODI-R and Annual Environmental Report. This remains a vital component to hold DNO actions and behaviours accountable to sound environmental practices, drive standardisation and consistency in reporting metrics and to instil a spirit of competition amongst DNOs.

Network operators also have a vital role to play in enabling wider societal decarbonisation, and in doing so, mitigating the national contribution to climate change. As such, DNO actions must be held against this wider benefit to ensure that whilst being appropriately held accountable, they are not disincentivised from delivering this over-arching objective. For instance, although not always visually appealing to some customers, new tower and pole overhead lines can be the fastest and most economical way to connect new renewable generation and are an inevitable part of the net zero transition.

As the societal transition to net zero progresses at pace, electrical networks will increase in size and utilisation which in turn increases the absolute and relative level of network losses. The impacts of this must be considered not just within CBAs, but also against the facilitation of low carbon technologies in reducing climate change, or the system flexibility to accommodate intermittent generation. We therefore also support the inclusion of losses in CBAs and decision making with regards to deferring or progressing reinforcement noting that this will increase the baseline cost of network interventions.

The impact of the European Union F-gas regulations is already influencing the electricity networks supply chain with manufacturers transitioning to SF6-free alternatives in line with EU requirements. The pace of this change, cost and availability of SF6-free plant will be key to a successful SF6 transition within ED2 and ED3.

We would welcome clarification from DEFRA on the future UK policy position on f-gases to most effectively inform the ED3 framework and wider supply chain. If the UK are to align with the EU regulations, this decision should be made as soon as possible to inform industry and give greater confidence to the supply chain. However, if the UK policy position is to deviate from EU policy, we believe this could potentially further constrain the UK f-gas supply chain. Irrespective of the UK policy direction, clarification is required on any appropriate exemptions/derogations that recognise difficulties DNOs may have if the supply chain cannot provide appropriate SF6 free alternatives for distribution networks.

We support the ED3 focus of further asset management practices to manage SF6 leaks from existing plant and working with industry to develop environmentally sustainable alternatives. Our view is that as the costs of this transition develop, Ofgem must work closely with DNOs through the ED2 Environmental Re-opener and ED3 Submissions to ensure that cost does not become a barrier to delivering essential network investment.

Although, we have not yet had call to employ the Environmental Re-opener in ED2, it plays a key role for DNOs to quickly react to emerging environmental regulatory and legislative changes which may occur. We support the retention of this re-opener within the ED3 period. Due to the

continuing uncertainty on future SF6 regulatory arrangements our expectation is that SF6 replacement will remain within the scope of the ED3 environmental reopener in ED3.

Question 61. Do stakeholders agree with building on the approach taken to cyber resilience in RIIO-3 for ED3?

Cyber resilience is a significant challenge for the next decade, encompassing the RIIO-3/ED3 period. Technology drives this challenge, being crucial for achieving net zero and delivering customer efficiency. Increased digitalisation, automation, and artificial intelligence heighten network risks from external actors, which SP Energy Networks takes very seriously. We therefore support the Competent Authorities' efforts in the electricity sector in Great Britain to ensure there is a robust cyber resilience framework.

Cyber Resilience Guidance

We endorse aligning the Network and Information Systems Regulations 2018 with RIIO Cyber expectations and consolidating the Cyber Resilience Re-opener Guidance with the NIS Supplementary Guidance. We urge Ofgem to streamline regulatory reporting and guidance for cyber resilience, providing clearer and more aligned assessment frameworks.

Allowances

We agree with Ofgem's proposal for DNOs to submit a combined IT and OT cybersecurity plan aligned with NCSC CAF Principles. We support setting baseline allowances for our Cyber Resilience plan and moving towards a single comprehensive Cyber plan. However, we would encourage Ofgem to consider some of the benefits and downsides of different regulatory mechanisms for funding cyber. Baseline cyber funding could, as being covered by the TIM, encourage innovation and efficiency, but could also lead to unintended consequences where efficiency might take precedence over additional investment in cyber, at a time when added risk and an uncertain external environment might call for more investment. We would urge Ofgem to consider whether a certain element of UIOLI funding might still be appropriate, for example for uncertain new projects. Ofgem should therefore consider if a combination of baseline funding and UIOLI allowances might be appropriate.

PCDs and Reporting

We acknowledge the proposal to reduce PCDs while ensuring compliance with NIS Regulations and aligning with the broader RIIO-3 approach. However, it remains unclear how material projects delivering the Cyber Assessment Framework (CAF) will be tracked and reported beyond PCDs. Mapping PCDs to the CAF presents challenges, potentially complicating funding applications and creating differences between operators. We support reducing regulatory reporting that does not benefit consumers.

Re-openers

As a minimum, we support Ofgem's proposals for a broad mid-period re-opener for Cyber Resilience to address changes in government policy, guidance, risk, technology, and major incidents. Maintaining the option for Ofgem to direct new re-opener windows is beneficial.

However, we think it would be better to propose a yearly Cyber Resilience re-opener that can be triggered by DNOs with the same broad scope.

Ofgem could consider how this specific reopener might be streamlined to align with reporting requirements and to reduce the burden on both DNOs and Ofgem.

Stakeholder Collaboration

Collaboration with stakeholders, including other DNOs, government bodies, and industry experts, is crucial for enhancing cyber resilience. This collective effort will help share best practices, address common challenges, and develop standardised protocols. Regular workshops, joint training sessions, and information-sharing platforms can foster a collaborative environment. Engaging with international bodies can also provide insights into global best practices and emerging threats. We would welcome Ofgem continuing to support companies to proactively collaborate in the interests of our customers to reduce risks.

Innovation and Research

Continuous innovation and research are essential to stay ahead of emerging cyber threats. Investing in new technologies, such as artificial intelligence and machine learning, can enhance threat detection and response capabilities. Research partnerships with academic institutions and technology firms can drive the development of advanced cybersecurity solutions. Pilot projects and testbeds can be used to trial new approaches in a controlled environment before wider deployment and we would welcome a collaborative approach from Ofgem and the wider community on this.

Customer Impact

Ultimately, we agree with Ofgem's added focus on cyber resilience. Additional measures will benefit customers by ensuring a reliable and secure electricity supply. Enhanced cyber resilience reduces the risk of disruptions, ensuring that customers experience fewer outages and better service continuity. Clear communication about cyber security efforts will also build customer trust and confidence. Additionally, protecting customer data and privacy is paramount, and robust cyber resilience measures help safeguard this sensitive information.

Question 62. What specific issues are network companies facing in relation to the skills and capacity of their workforce and what measures should we take through the regulatory framework to mitigate these issues?

The largest issue facing network companies with regard to workforce capacity and skills is the major talent shortage. The UK lacks the skills workforce that is required to deliver decarbonisation at the scale and pace proposed by UK and Scottish Government targets, and there is an overall lack of availability of people in general in the UK to support energy transition. It has been estimated in a recent report published by Energy Utilities Skills that more than 300,000 new people will be required in the energy and utilities sector between now and 2030.

Examples of measures that we believe could mitigate the skills shortage include:

- The Government should work with career influencers, the energy sector and high schools to remove the stigma around apprenticeships, which are still often viewed as less desirable than university degrees. This must be addressed in order to support the required growth of the industry.
- The industry needs to come together and increase its focus on diversity and inclusion to be fully accessible to, and help increase, the talent pool available. We are working closely with EU skills in a cross sector working group to create an action plan focussed on improving EDI and social inclusion. We are continuing to build on our EDI strategy to promote a more diverse workforce.
- The skilled overseas worker legislation is too restrictive and costly for the energy industry, and we rely on overseas workers as we build out the pipeline of talent for key roles. Due to the current skills and capability gap, there is a requirement to recruit many skilled roles, such as design engineers and protection and control, from overseas. There is a need for a review of this legislation to bring it in line with the skills growth required for the UK.
- The UK lacks a cohesive skills agenda. While Skills England was promising, there is currently nothing on the agenda to bridge the divide with the nations and bring the skills shortage to the forefront as a need for all of the UK, not just the devolved nations. The Office for Clean Energy have set out that they plan to work with the sector, trade unions and the devolved governments to support regions transitioning from carbon-intensive industries to clean energy sectors. In particular, it has identified interventions to reskill and upskill workers across the economy, supporting access to training schemes.
- The apprenticeship levy needs to be made available for use in Scotland and opened further so that the funds can be used meaningfully for upskilling. The apprenticeship levy is not available for use in Scotland and is still too restrictive in its uses. We need this opened further and for use in Scotland so we can utilise the funds meaningfully for upskilling and reskilling. This would support the industry increasing the trainee population to support the heightened demand.
- In addition to ensuring that the ED3 settlements include sufficient training allowances, Ofgem could consider rewarding companies for long-term resource planning as we need to ensure that DNOs are thinking about future career pipelines and the talent required. Rewarding companies for planning in advance of need would support net zero delivery.

Question 63. What specific issues are supply chains facing and what measures should we take through the regulatory framework to mitigate these issues?

From an equipment perspective, increased global demand has led to lead times increasing in many cases. This also means that delivery costs are increasing. As outlined in our response to question 11, for manufacturer lead times, some of the changes we have seen in the last five years include:

- [REDACTED]

These are just the timescales to receive the assets, we then need to install them. Demand for workforce and greater localisation mean we are seeing an increase in contractor labour rates and longer lead-times until they are available. As a result, DNOs are having to forecast for longer horizons and seek to expand our supply chains to access as wide a capacity picture as possible to manage delivery risk. A roll out of the Advanced Procurement Mechanism proposed for R10-T3 could also be considered for Distribution to help mitigate supply chain and delivery risk, while improving workforce planning, and this should be explored further during ED3 Working Groups.

From a works perspective, contractor capacity is a concern; examples are the areas of Overhead Lines (where we are competing with Transmission growth) and Vegetation Management (again competing with Transmission growth but also impacted by the electrification of Railways in Scotland and new lines requiring clearance distances). Contractors continue to face challenges with resourcing, with specific skilled segments of the industry suffering wage inflation, which has led to existing resources moving roles, without increase to the overall resource pool.

The ED3 framework should reflect that asset and labour costs are increasing, reflect that manufacturer commercial terms are changing (as they now pay more upfront instead of on delivery), consider allowances for DNOs to hold more stock (especially for high volumes standardised assets such as HV/LV transformers), and maintain regulatory flexibility for earlier procurement and stock holding (especially if a more rigid Plan & Deliver regulatory model is developed).

The issues facing workforce resourcing are consistent with those listed in question 62.

Question 64. Given our comments in Chapter 6 around taking a more proactive approach, are there any specific features of a more anticipatory or strategic investment approach that might create risks or opportunities for supply chain and workforce constraints?

We believe a more proactive approach to strategic investment could provide the workforce and supply chain with greater long-term certainty.

To assist with this, it would need to manage risks around resource and skills timing:

- Ensuring that appropriate lead time is built into a more proactive approach, to ensure that DNOs and the broader supply chain have sufficient time to secure the resources required.
- Factoring in the timing around availability of skills. The majority of our field workforce is filled with craft roles, most which come through our trainee programmes, and as these positions are difficult to fill from market, they have a significantly longer lead time.

A strategic approach also presents opportunities to do things differently in relation to security of the supply chain and workforce. For example:

- If DNOs established long term contracts with the supply chain, it would encourage investment in the training and development of new recruits.
- The regulatory framework could incentivise DNOs to work with their supply chains on resource planning and encourage sector wide workforce planning which would help provide workforce stability in the long-term.

- The adoption of a greater number of industry level initiatives at earlier stages of the resourcing process, i.e. STEM within schools, promotion of the overall industry at school.
- There is an opportunity to further invest in training infrastructure to sustainably develop our home-grown talent across all DNOs. We would welcome Ofgem support to allow us to make a substantial investment in training infrastructure which would provide a comprehensive, regionalised and scalable skills supply chain intervention by fostering the rapid development of a motivated and adaptable workforce, essential for sustaining growth and competitiveness. This could support industry level programmes and support the GB-wide supply chain.

Question 65. What would the benefits be of a geographical approach to delivering new and upgraded assets in terms of supply chain and workforce constraints?

The UK lacks the skilled workforce that is required to deliver a decarbonised network with a fundamental lack of networks training facilities across the UK. Targeted and regionalised education and training facilities are required on a massive scale to bridge the rapidly expanding skills gap. As indicated in our response to question 64, we would welcome Ofgem support to allow us to make a substantial investment in training infrastructure which would provide a comprehensive, regionalised and scalable skills supply chain intervention by fostering the rapid development of a motivated and adaptable workforce, essential for sustaining growth and competitiveness. There can be no further delay or lack of ambition - a multidisciplinary skilled workforce is critical to delivering the ambitious UK industrial decarbonisation strategy and unlocking the value the transition to a net zero economy.

It would be useful for Ofgem to incentivise DNOs to complete Energy & Utility Skills' Annual Workforce Planning survey ensuring there is comprehensive geographical methodology to understanding where roles within the industry exist and skills gaps are identified. This would enable greater visibility and allow access for the wider talent pool and support the creation of a more sustainable talent pipeline. In addition, there would be more tangible benefits to the communities and the local economy.