ED2 Draft Determination response

KEY POINTS

- There are critical flaws in the DD that combine to create a real risk that the DNOs will become a barrier to urgently needed societal change – but they can be fixed.
- Mistakes in Ofgem's cost modelling will leave DNOs underfunded to deliver net zero if they are not corrected.
  - Ofgem actively encouraged companies to submit incomparable plans that embody different future decarbonisation pathways.
  - To try to overcome this Ofgem has developed its most complicated benchmarking framework to date, but this has fundamental flaws.
  - Ofgem must either drop the demand-driven adjustment or make important changes to its totex and disaggregated modelling, alongside fixing a range of other errors within its benchmarking models.
- The funding gap is made worse by the entirely unjustified "stretch" added at the end.
  - Ofgem applies an unjustified ongoing efficiency challenge of 1.2%, which has already been rejected by the CMA twice.
  - There is also an unwarranted and material reduction that results from setting the efficiency frontier beyond the upper quartile, gliding to the 85th percentile.
  - If Ofgem does not change course, it will almost certainly trigger sector wide appeals that will prove to be a costly distraction.
- Ofgem then irrationally misallocates allowed costs between categories, creating an excessive allocation to secondary reinforcement paid for by providing far too little allowance to all other cost categories.
  - The problem can be easily remedied by allocating totex properly, in line with Ofgem's baseline scenario.
- Ofgem's baselines cover spend needed only in the least ambitious decarbonisation future pathway, but the automatic UMs that should release further funding if society moves faster on net zero will fail to do so, as essential indirect costs are not provided for and smart and flex solutions are not funded at all.
  - The proposed unit costs only cover the direct costs of work. This is a basic error.
  - The baseline allowances for secondary reinforcement must include incentives to choose smart or flexibility solutions. This is a glaring omission from Ofgem's proposals.
- Ofgem is planning to set allowed returns too low.
  - Ofgem must get this right to ensure that investment remains attractive and to protect customers from the profound risks that would arise if allowed returns are set below the marginal cost of investment.
- An understandable focus on short run bills risks turning into misguided, short-term thinking and on inflation that short termism risks straying into opportunism.
- There is much work to do over the months ahead to ensure that ED2 is made "roadworthy". Ofgem must now work with us, and other stakeholders, to get key aspects of the price control right.

August 2022

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1. Summary

There are critical flaws in the DD – but they can be fixed

1. Electricity distribution is set to be at the heart of society's transition to net zero. The five years covered by the RIIO-ED2 price control are a vital period in that journey. Stakeholders have been clear that delivering on net zero and keeping downward pressure on bills are the top priorities. To enable that, the price control has to:

    a. create an environment where DNOs are incentivised to make the investments that are required to facilitate this transition as efficiently as possible;

    b. set a baseline level of funding that allows DNOs to plan effectively; and

    c. be agile and flexible enough to ensure that additional, efficient funding is provided in a timely way if society requires DNOs to move faster than the allowances in the baseline allow.

2. In its ED2 Draft Determination ("DD") Ofgem proposes to restrict baseline allowances to those that will allow DNOs to meet what Ofgem itself describes as the least ambitious future net zero pathway. By definition, this raises the stakes on the quality of Ofgem's decisions. It demands that they take care to ensure that they do not make mistakes that lead to a shortfall in funding, which would set the country on a course to fall short of its decarbonisation objectives from day one. That applies not only to the baseline allowances but also to the design of the proposed uncertainty mechanisms ("UMs"), which are Ofgem's preferred means of funding any investment that will be needed if the country moves at a pace that exceeds the least ambitious pathway that informs Ofgem's baseline. Our assessment of the DD is that considerable work is needed if ED2 is to meet these requirements and enable DNOs to deliver to their full potential for customers and stakeholders.

    a. The proposed set of UMs suffer from important design deficiencies that render them unfit for purpose.

    b. Ofgem's complex and unwieldy assessment of plans significantly underestimates the costs required to deliver the service levels and outputs envisaged, a problem that is aggravated by imposing an unrealistic degree of efficiency challenge that is unsupported by the evidence.

    c. The incentives for DNOs to invest and continue to drive improvement have been seriously weakened because of key design flaws in the arrangements, and because the contemplated level of allowed returns does not reflect ongoing changes in capital markets.

3. These shortcomings combine to create a real risk that the DNOs will become a barrier to urgently needed change, rather than leading the charge.

4. But there is a way forward. Many important changes are needed to the DD proposals, but we are committed to working constructively with Ofgem, the wider sector and all stakeholders to fix the problems, to create a price control that will allow DNOs to deliver.

5. Even if Ofgem were to make the changes that are needed just to provide a Final Determination ("FD") that does not create immediate barriers to progress, there will still be good reason to be concerned that the resulting price control will fall short of delivering the best long-term value for customers. It is clear that some key RIIO principles have been diminished and, in some cases, jettisoned. Ofgem has steadily shifted to a point where it is now intending to rely far more on uncertainty mechanisms, ex post assessment, clawbacks and a reduction in rewards where a company finds a more efficient way to deliver, rather than delivering a price control founded on proper incentives. Diminishing incentives will be harmful to customers, with the cost to them building slowly and over a long period of time.

6. Proper incentive regulation has been proven to provide the best outcomes for consumers even during normal times, when all that is needed might be described as business as usual. In the context of the challenge of achieving net zero, it is more important than ever that companies are subjected to strong incentives to adapt, innovate and search for novel ways to address old and new challenges. Done right, incentives will unlock large savings for customers now. And these savings could be huge in the long run, if well designed incentives encourage companies to search for and find quickly the very best blueprint for the efficient networks of the future.

7. That said, we recognise the need to be pragmatic about what can be achieved in the short period of time that remains before Ofgem must publish its FD. The focus over the coming months must be on delivering baseline funding for a relatively unambitious future, coupled with UMs that do not create barriers to going faster if needed. The changes we propose are targeted at delivering a price control that can be said to be fit for *this* purpose, even if the weakened incentives within it will not serve consumers as well as they could. We continue to look to Ofgem, however, to do more on this during the ED2 period and beyond. We are committed to working with them to that end.

8. Therefore, our focus here is on the key problems with the DD and the essential changes that are needed. More detail is provided in the body of our response and in the detailed answers we provide to Ofgem's consultation questions.

Mistakes in Ofgem's cost modelling will leave DNOs underfunded to deliver net zero if they are not corrected

9. Despite being urged to do so, Ofgem decided not to define a common future scenario to support business planning. Instead, Ofgem actively encouraged companies to take their own view of what scenario they should plan for in their business plan baselines, and what costs might fall into UMs in (divergent) higher uptake scenarios. The result is a set of business plans that contain costs that are far from being directly comparable across companies as they embody different future decarbonisation pathways.

10. Consequently, Ofgem has created for itself a benchmarking challenge that is far more complex than it needed to be. To try to overcome this Ofgem has developed its most complicated benchmarking framework to date, which:

    a. adds variables that purport to control for differences in scenario to its totex benchmarks – *some of these work to at least some degree*, **others do not**;

    b. makes a range of volume disallowances through its detailed disaggregated models that are poorly documented and evidenced, leading to the unjustifiable position that all networks are found to be highly inefficient in this part of Ofgem's model; and

    c. on top of the challenge from its totex and disaggregated models, subsequently applies a novel demand-driven adjustment, intended to scale down cost allowances to match Ofgem's preferred scenario (ESO System Transformation).

11. A fundamental problem with this approach is that it will lead to an efficiency double count. Through the demand-driven adjustment, it will adjust down cost allowances to reflect fully any differences in scenario definition. But earlier steps in the process will have already 'benchmarked away' some of this difference, leading to an inevitable risk of double counting potential savings.

12. It is too late for Ofgem to conduct a fresh data gathering exercise focused on a common scenario, and there is no scope to achieve better consistency in the benchmarking by changing the benchmarked scenarios. Either of these changes would in effect throw the entirety of the DD modelling in the bin and require Ofgem to start again. There is now not enough time, and asking the DNOs to resubmit plans after they've seen Ofgem's models would introduce the potential for a company to game the outcome.

13. Instead, Ofgem must either drop the demand-driven adjustment, or work with us and the sector to make important changes to its totex and disaggregated modelling, alongside fixing a range of other flaws with its benchmarking models, described in our detailed response.

The funding gap is made worse by the entirely unjustified "stretch" added at the end

14. The mistakes in Ofgem's benchmarking already lead to allowances that are too low. But Ofgem then takes these and applies two wholly unjustified additional stretch factors.

15. Ofgem is minded to apply an ongoing efficiency factor of 1.2%.

    a. All reasonable evidence points to the number being lower, potentially much lower.

    b. The same is true of all regulatory precedent.

    c. Yet it seems clear that, contrary to all the evidence, Ofgem is wedded to make another attempt to set an ongoing efficiency of 1.2%, even though its two previous attempts to impose a high stretch beyond the evidence were quashed on appeal to the CMA.

d. If Ofgem sticks to its position in the FD the result will be an efficiency challenge that is at odds with the evidence, unreasonable and wrong.

16. Ofgem is also minded to apply a further additional source of unjustified stretch, by setting the efficiency frontier in its benchmarking beyond the upper quartile, relying on a glidepath to impose a stretch up to the 85th percentile.

a. Long standing regulatory precedent supports the use of the upper quartile (75th percentile) level of performance to determine cost allowances in a regulatory cost benchmarking exercise.

b. This strikes an appropriate balance between setting tough but fair allowances, while also recognising that intrinsic limitations within any benchmarking models require the cautious translation of results into allowances.

c. Despite all the evidence suggesting that Ofgem's benchmarking models are, if anything, less robust than was the case at previous price controls, Ofgem proposes instead to rely on them more completely than ever. This is illogical, unreasonable, and wrong. Unlike the GD2 price control, the effect is highly material.

17. Ofgem must change course in respect of both of these unjustified adjustments. Otherwise it will almost certainly trigger sector wide appeals that will prove to be a costly distraction for both Ofgem and the networks.

Ofgem then compounds the problem by irrationally misallocating allowed costs between categories

18. The complexity of Ofgem's approach has also introduced a significant distortion in the allocation of the allowances that it has judged to be efficient. The problem arises because Ofgem's method in effect replaces our planning scenario with a less ambitious scenario, containing far less load related activity. Despite this, Ofgem has chosen to allocate final totex allowances to each cost category in line with the proportions in our business plan submissions, not in line with their likely scale in Ofgem's lower scenario. The end result is an excessive allocation to secondary reinforcement, paid for by providing far too little allowance to all other cost categories.

19. This would not matter if Ofgem was not making such a significant change of direction in terms of applying the RIIO principles of driving cost efficiency through well-calibrated incentives that encourage companies to find efficiencies, which are then shared with customers. Such an approach would look to set a single overall totex allowance in which underlying allocations were irrelevant. But instead Ofgem is relying heavily on activity-driven UMs to fund decarbonisation, and these mechanisms fund specific cost categories. The baseline funding for cost categories where funding may flex through a UM therefore needs to be set at the right level. Unless it is fixed, Ofgem's irrational and inconsistent allocation method risks creating a further material funding shortfall.

20. The problem can be easily remedied in the FD, by allocating totex to cost categories in line with Ofgem's underlying planning scenario.

The automatic UMs will fail to release the right level of funding, because essential indirect costs are not provided for…

21. Ofgem is seeking to impose on the sector a baseline consistent with the ESO's 2021 System Transformation scenario, a scenario that contains the lowest level of electricity distribution activity amongst all authoritative net zero consistent scenarios. It is likely, then, that a higher demand scenario will emerge than is embodied in the baseline allowances, such as the one implied by current Government policy in relation to heat pumps and electric vehicles. DNOs will be required to respond and will need additional funding through UMs to do so.

22. But as it stands, the unit costs proposed for Ofgem's volume driven UMs in key load related categories (particularly, secondary reinforcement and LV services) only cover the direct cost of the work. There is currently no funding for the much wider set of indirect activities needed to deliver those additional projects, such as engineers to design schemes and payments to landowners for the rights to install cables on their land.

23. This is a basic error - it is a matter of common sense that delivering higher direct investment requires higher associated indirect costs. This must be fixed in the FD.

…and smart and flex solutions are not funded either

24. Ofgem's secondary reinforcement volume UMs are designed as mechanistic volume drivers. However, units have only been defined for traditional capital-based reinforcement. There are no units defined for smart or flexible solutions. As a result, Ofgem's proposed funding mechanism for arguably the most important category of investment where net zero is concerned is simply not capable of providing any funding to DNOs to procure flexibility or invest in smart solutions at these lower voltage levels.

25. This is a glaring omission from Ofgem's proposals, particularly given Ofgem's perfectly legitimate emphasis on the need for a "flexibility first" approach and the potential significant scaling up of secondary reinforcement work in scenarios above the baseline. The consequences of this alarming mistake are serious.

    a. Failure to provide funding will create a key barrier, strongly discouraging DNOs from exploring and adopting smart or flexibilty-based solutions.

    b. Other aspects of the price control that facilitate flexibility cannot hope to overcome the complete absence of funding through key UMs.

26. Unless this gap in the framework is addressed, customers will lose out in a very significant way. DNOs will be encouraged simply to roll out traditional solutions, even where more efficient alternatives might have been available. Costs will be higher than they need to be. This defect must be fixed.

The baseline allowances for secondary reinforcement must include effective incentives to choose smart or flexibility solutions

27. The best way for Ofgem to deal with the problem it has created in the current proposal is to use one of the central features of the RIIO approach to setting price controls: clear incentives on cost efficiency. It should confirm that it is providing ex ante baseline allowances for secondary reinforcement (i.e. funding that is not conditional on a volume-driver or with risk of regulatory clawback). By doing so Ofgem would provide DNOs with a clear incentive within the baseline scenario to find the most efficient solution - including procuring flexibility or installing smart solutions where it is efficient to do so, and to optimise across voltages and between maintenance and replacement.

28. This is the best way to encourage companies to adapt, innovate and search for novel ways to address old and new challenges. The information that such incentives are capable of revealing, around how and where these (still relatively new) solutions can be deployed, can lower costs immediately, and can subsequently be baked in to baseline allowances for ED3 and beyond generating very large long run savings. If Ofgem fails to set an ex ante allowance, these important incentives will be undermined to the detriment of customers.

29. The potential benefits of introducing proper incentives in this key area can be secured without exposing customers to any material risk of, for example, windfall gains. Ofgem has moderated this risk through its decision to set baselines in line with the least ambitious scenario. There is no prospect that companies will be given an ex ante allowance that they simply do not need. Ofgem has also introduced a further safety net at RIIO-2, in the form of its Return Adjustment Mechanisms. Given the potential benefits, and that any residual risks to customers are so comprehensively managed, there is every reason to make this change, and no good reason not to.

Ofgem is planning to set allowed returns too low

30. As we have set out throughout the RIIO-2 process, Ofgem's approach to setting allowed equity returns is flawed and unbalanced, and in respect of cost of debt key details are still not adequately allowed for. With evidence mounting that momentum in capital markets is shifting, as central banks around the world tighten monetary policy, it is time for Ofgem to revisit the evidence to ensure it sets allowances for both debt and equity that not only look reasonable now, but will remain reasonable throughout what may be a challenging and turbulent period ahead.

31. On equity, it is understandable that Ofgem is looking to stick with a method that has survived appeal. But at the very least, Ofgem will need to take account of the latest evidence on Total Market Returns. The authoritative DMS database now reports higher long run average nominal returns than was the case when Ofgem set its estimate earlier in the RIIO-2 process. And the ONS has updated its CPI backcast, on which Ofgem has placed considerable weight. This backcast now shows generally lower levels of historical CPI inflation. Both of these factors imply

that Ofgem's central estimate of 6.5% real CPIH is now far too low. A material uplift to allowed returns is warranted versus Ofgem's DD for these factors alone.

32. It is critical for Ofgem to get this right, in order to ensure that investment remains attractive throughout ED2 and to protect customers from the profound risks that would arise if allowed returns are set too low. In our plan we explained that we had worked with financial expert Oxera to review the evidence. Oxera concluded that the cost of equity for companies in our sector was at least 5.8% real CPIH. Current market evidence still supports that conclusion.

An understandable focus on short run bills risks turning into misguided, short-term thinking…

33. It is understandable that Ofgem has placed a strong focus on bills and the impact on bills of their proposals. Even before current world events created the growing cost of living crisis, our stakeholders had made it clear to us just how important it was for us to keep costs low, and to seek best value on their behalf wherever possible. However, in addition to having regard for the current circumstances, Ofgem has a duty to guard against the risk that an over-focus on the short run leads to them having insufficient regard for some profound long run risks that will remain long after the current problems have abated and will be borne by future customers.

34. In respect of ensuring that DNOs can continue to invest at the necessary levels, we have material concerns with Ofgem's direction of travel in two areas: regulatory depreciation and inflation protection. In both of these areas, Ofgem runs the risk of loading cost on future consumers and failing to balance fairly between generations.

35. We have long argued for Ofgem to revert to using a shorter regulatory depreciation period, to create much needed financial headroom to help fund any major increase in investment for the low carbon transition. The evidence suggests that around 25 years would:

    a. result in better intergenerational fairness between current and future payers;

    b. help to manage what will otherwise be a huge growth in RAV growth over the coming decades, which in turn will drive long-term increases in prices; and

    c. reduce the strain on future financeability assessments, which could limit the ability of the sector to respond to future investment needs.

36. Despite this Ofgem seems determined to stick with its plan to adopt a 45-year regulatory depreciation period for all assets from ED2 onwards. We urge Ofgem to keep this topic under review, as our modelling suggests that even without any growth in expenditure RAVs would approximately double and long run DNO charges may grow by 70% in real terms.

37. Given the speed with which RAVs – and bills – will grow going forwards, we urge Ofgem to act on this now. If Ofgem fails to act at ED2, ED3 is the last opportunity to act before Ofgem becomes locked into long depreciation periods, large RAVs and higher bills.

…and on inflation that short termism risks straying into opportunism

38. Ofgem's consultation questions on whether it should change its approach inflation indexing and setting real allowed returns are extremely troubling.

39. The existing arrangements have been the basis of a successful investment story in the UK regulated sector for 30 years, and companies have financed themselves based on the legitimate expectation that the prevailing arrangements would endure. A change now would represent a major and sudden change in investors' risk exposure which would fundamentally disturb their chosen financial risk management strategy. To adapt financing structures to reflect any change would impose large costs on the sector.

40. Seeking change now would be highly opportunistic, coming as it does after a long period when inflation has been largely below expectations.

41. Ofgem's consultation is vague. Not only does it fail to identify what changes are currently being contemplated, it fails to even identify that there is a problem that needs fixing in the first place.

42. On the contrary, it is clear to us that there is no problem with the current arrangements. Under the prevailing arrangements networks are compensated once and only once for inflation through RAV indexation. They then receive a reasonable real rate of allowed return on that inflated RAV, reflecting the risks of the business. How this reasonable rate of return is allocated between debt and equity investors will vary depending on the form of debt finance issued by each company. But it is only a question of allocation, not of level, and Ofgem has always been crystal clear that financing decisions are a matter for each company. That position has been the basis upon which Ofgem has flatly, and repeatedly, refused to provide additional funding to companies when legacy debt has been expensive compared to overall market rates.

43. Even if Ofgem were to (wrongly) conclude that there is a problem that needs fixing, it seems clear that any "remedy" would, in effect, be equivalent to only partially indexing the RAV, a step that would profoundly alter the long-standing commitment to investors around inflation protection. An apparent willingness to consider tinkering with inflation protection, arriving without any prior signal just months before the end of a price control process that has run for years has, in and of itself, already been disturbing for investors.

The way forward

44. There is much work to do over the months ahead to ensure that ED2 is made "roadworthy". And the necessary changes we set out here will not be sufficient to fully restore proper incentives – with the resulting cost borne by current and future consumers – which leaves important areas where more work will be needed down the line, during ED2 and into ED3.

45. Ofgem must now work with us, and other stakeholders, to get key aspects of the price control right. If it does, and if full and deep engagement continues into the ED2 period itself, we are confident that ED2 can be made into a price control that will genuinely support solid progress towards net zero. We should all aim to do better still in ED3.

2. Responses to Ofgem's consultation questions

Question 1: Do you agree with our proposal to introduce a new funding mechanism for PoLR activities?

46. Yes. It is reasonable that there is a funding mechanism that would cater for a situation, if it ever came to pass, where the licensee was obliged to become a provider of EV Recharging Points in order to comply with Ofgem's direction and so incur the associated costs on an ongoing basis.

Question 2: What are your views on our two proposed options, and do you agree with our preferred option of a DRS?

47. The most appropriate funding mechanism is pass-through.

48. In the event that Ofgem issue a PoLR direction to a DNO, the DNO should automatically pass-through any revenue and costs it has directly incurred from undertaking its legal obligation, to consumers. This would be through Distribution Use of System (DUoS).

49. Directly Remunerated Service (DRS) does not provide a funding mechanism, it would involve us setting prices and charging customers directly which introduces risk and a significant administrative burden. Moving the service within the core revenue control, as pass-through, gives us a funding mechanism.

Question 3: Do you agree with our proposal to introduce a re-opener to deal with recommendations from the Storm Arwen review, our proposed trigger and re-opener window?

50. Yes, we agree with the proposed Storm Arwen re-opener.

51. A re-opener is the most appropriate funding mechanism for any change in the scope of work DNOs are expected to deliver as a result of the Energy Emergencies Executive Committee (E3C's) or Ofgem's recommendations from the Storm Arwen review. The level of potential change to resilience standards and specifications is uncertain at this stage.

52. It seems sensible that the DNOs will have one opportunity to trigger in January 2024 and the timing should provide sufficient time for DNOs to identify and cost any required changes if they are required to be implemented in ED2.

Question 4: Do you agree with our proposal to maintain the RIIO-ED1 High Value Project mechanism and focus it on non-load related HVPs in RIIO-ED2?

53. Yes, we agree with the proposal to maintain the RIIO-ED1 High Value Project mechanism and focus it on non-load related HVPs in RIIO-ED2.

54. While we have not submitted costs in this area for ED2 we welcome the proposal to maintain the re-opener mechanism in the event that costs arise during the control period.

Question 5: Do you agree with our proposal to remove the RIIO-ED1 smart meter volume driver?

55. We do not agree with the proposal to remove the RIIO-ED1 smart meter volume driver. The proposal is to only provide an ex ante allowance using a median unit cost based model. This

replaces the ED1 approach of an ex ante model plus an uncertainty mechanism with a volume driver. We do not agree with this approach on three key points:

a. The uncertainty mechanism should be maintained. There remains a degree of uncertainty around how successful the roll out will be to 2025. We can forecast the number of installations but whether (or when) suppliers will meet the targets is beyond our control.

   i) There is a large backlog of completed interventions which (as per the RIGs) we have not claimed allowances for as smart meters have not yet been installed. The proposed approach would see us lose this allowance if these are not claimed by the end of ED1 whilst the mechanism is still in place. This is also beyond our control.

b. The model makes significant adjustments to the submitted intervention volumes by applying a 3% industry median intervention rate to the forecasted installations rather than using the actual intervention volumes forecasted. This disproportionately benefits DNOs that have a low historic intervention rate and have submitted an optimistic view of the installations to the end of the roll out period. A subjective forecast view by DNO of what suppliers will do should not drive the cost assessment.

c. Applying the 3% median intervention rate to forecasted installations as a 'one size fits all' approach for volumes is not reasonable. This parameter is not within the DNO's control unlike unit cost. Applying the median penalises DNOs with a higher intervention rate, backed by historic data, often due to the historic age and condition of equipment on the network.

56. Based on the above we would support an approach which adopts one or more of the following:

a. The ex ante allowance is provided but the uncertainty mechanism is maintained.

b. The same rollout scenario (forecast installations) is applied to all DNOs based on a percentage of customer numbers. If we are assuming a successful rollout this would be close to 100%.

c. An intervention rate aligned with individual DNO actual submissions is used and is therefore reflective of a region's asset population.

Question 6: Do you agree with our proposed approach for a common materiality threshold being applied to RIIO-ED2?

57. Yes, we agree with the proposed common materiality threshold.

Question 7: Do you agree with our view that all the DNOs have passed Stage 1 of the BPI?

58. Yes, we agree that all the DNOs have passed Stage 1 of the BPI.

Question 8: Do you agree with our overall approach regarding treatment of CVP proposals?

59. No, we do not agree with the overall approach.

60. Other than the one-stop app for vulnerable customers, which was included as an independent cost line item, we are being asked to fund accepted CVPs through baseline allowances. Ofgem

has applied significant cost disallowances across the plan, while at the same time accepting most of our output commitments, creating insufficient cost allowances to fund outputs.

61. We will need to review and prioritise the costs and delivery for the two unfunded CVPs (voltage optimisation and open insights) alongside other outputs within the baseline cost envelope.

Question 9: Do you agree with our proposed position on early and late competition?

62. Yes, we agree with the proposal. We understand the position that Ofgem has arrived at and agree with the logic that has brought them to this conclusion.

Question 10: Do you have any views on the proposed scope of the FDQ process and pre-action correspondence, including on the proposed timing for sending such to Ofgem?

63. In its Open Letter to Ofgem dated 30 October 2019 (the "Open Letter"), the CMA explained that:

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

64. This clearly represents good practice. If appellants are obstructive then the CMA will take this into account in its cost order. However, and despite the intent of the FDQ process for licensees to ask clarification questions and to notify Ofgem of any errors, Ofgem's construction of what this means for pre-appeal conduct is lopsided and stretches the CMA's statement well past the credible.

65. Ofgem's position is that, in line with its RIIO-GD&T2 determination, it expects potential appellants to:

   a. come forward to clearly explain their intention to appeal, the element(s) of the RIIO-ED2 price control that they intend to appeal, the scope of that appeal including, in sufficient detail, the alleged errors, and why that particular component of the price control is wrong having regard to interlinked aspects of the decision; and

   b. send pre-action correspondence at a sufficiently early stage, between the publication of FD and ahead of the deadline for filing appeal. We would expect to receive this correspondence in the period between early December 2022 to early February 2023 - after publication of FD and before we are due to publish a decision on the corresponding RIIO-ED2 licence conditions.

66. Ofgem's position is unreasonable, and it ignores the following:

a. Given the various consultations (including this one) that lead up to a price control decision, it is virtually certain that that any appellant will already have engaged with Ofgem in detail before the Authority takes its decision.

b. A price control decision is complex and multifaceted. It takes a long time to digest, after which a prospective appellant has to determine if any elements of it are wrong. Following those two steps, it has to decide whether or not it is in its interests to appeal. This can be a finely balanced decision. A prospective appellant is – for good reason – highly unlikely to be able to provide the information to which Ofgem thinks it is entitled in the timeframe Ofgem expects.

c. Ofgem is asking for this information before the Authority has actually taken the decision which is subject to appeal – the decision to modify a licence. This is absurd.

67. Ofgem also considers that the pre-action correspondence:

a. should also cover the question of interlinkages between a decision appealed and linked aspects of the price control.

68. In fact, the Open Letter provides that:

a. [t]o the extent that such interlinkages form part of the response to an appeal, in stating that an error on one part of the price control is linked to another part of the price control, we encourage regulators to explain these interlinkages, and the reasons for them, in their decision documentation

69. Before going on to add, as noted in the DD, that:

a. [w]here there are such interlinkages described clearly by the regulator, we would encourage appellants to explain why the component under challenge is wrong having regard to the interlinked aspects of the decision [emphasis added]

70. It follows, then, that the first instance at which interlinkages would be addressed are in the Authority's Final Determinations, to the extent there are any links. Provided those links are set out sufficiently clearly, an appellant would be wise to address them when lodging an appeal.

71. The efficacy and legitimacy of the appeal process is one of the cornerstones of the regulatory regime. It represents the only backstop investors have. Ofgem's positions on interlinkages, post-appeal reviews and pre-appeal correspondence all seek to skew this process in Ofgem's favour. They represent a reluctance to accept that appellants have focussed appeal rights and, when they exercise them, the Authority shifts from being a decision maker to a defendant, on an equal footing with the claimant.

72. On the one hand, as the appeal process is set out in statute and the CMA's rules, it shouldn't really matter what Ofgem's position is. The CMA is the arbiter. But on the other hand, Ofgem's attempts to put a thumb on the scales and its reluctance to be properly held to account necessarily damage investor confidence.

Question 11: Do you agree with our proposal to not introduce a specific uncertainty mechanism to manage the impact of the Access SCR (and address it through the LRE mechanisms instead)? Please explain why.

73. We agree with Ofgem's proposal not to introduce a specific uncertainty mechanism to manage the impact of the Access SCR. We do not believe the driver of the investment, Access SCR or otherwise, would be easily identifiable and therefore it would be a challenge to separate costs.

74. Ofgem must provide clarity on the funding routes for the impact of Access SCR. Ofgem has provided ex ante baseline allowances for both primary and secondary connections-driven reinforcement; we agree with this approach as it gives the DNOs a clear incentive to find the most efficient solution. DNOs' shares of indirect costs are funded in the ex ante indirect allowances. However, it remains unclear how Ofgem proposes to fund any additional connections-driven reinforcement above this baseline. Ofgem should fund this additional investment for secondary reinforcement through the volume driver and for primary reinforcement through the re-opener. For secondary reinforcement, as detailed above, Ofgem must fund indirect costs and confirm whether connections-driven secondary reinforcement requires additional work units (i.e. different to the volume drivers provided for routine capital work).

75. Ofgem need to be cognisant that some connections-driven reinforcement may require additional cost (e.g. primary substation level) that are not covered by the volume drivers, these additional costs would need to be split out and funded through the re-opener.

Core methodology

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

76. Yes, we do agree with the enduring role of the CEG.

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

77. No, we do not see the value in the CEGs working together to produce co-ordinated and comparative reporting across the DNO commitments. The value of working with our CEG is to focus on Northern Powergrid plans and commitments and how these are closely linked and respond the priorities of our local stakeholders.

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

78. No, we do not agree with the proposal as we believe that there are fundamental weaknesses with the approach taken to establish a baseline level of investment and some of the design aspects of the uncertainty mechanisms (covered in responses to questions 4 to 6).

79. We accept Ofgem's proposal to set baseline allowances by reference to common decarbonisation pathway, but we have material concerns over the methodologies being used to scale the investment down, combined with the approach to disaggregated benchmarking as

we discuss in subsequent answers to this consultation (see responses to questions 65 to 70 and 105).

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

80. Ofgem took a decentralised approach to determining demand forecasts; as a result, companies based their plans on a wide range of very different decarbonisation scenarios. To try and control for these inconsistent and therefore incomparable inputs, Ofgem replaced those scenarios with a common low scenario (FES 2021 System Transformation). Consequently, the baseline cost allowances were built on an uptake in LCTs that represents the lowest level of decarbonisation that is still consistent with the government's legally binding target for net zero carbon emissions by 2050. This means it is likely higher demand scenarios will materialise and having a mechanism to cater for any additional investment which reacts in an agile, flexible manner is essential. The potential need for a material increase in investment above Ofgem's baseline funding will be further compounded by the impact of Access SCR.

81. Ofgem has proposed an LRE 'toolkit' comprised of automatic and administrative mechanisms aimed at allowing investment to dial up in response to new demand, including a:

    a. Secondary reinforcement volume driver (automatic);

    b. LV services volume driver (automatic); and

    c. Re-opener for all other load-related expenditure not covered by a volume driver (administrative).

82. A workable solution must:

    a. Never act as a barrier to delivery in higher demand scenarios;

    b. Fund and incentivise investment in network flexibility and smart solutions; or

    c. Effectively control for the uncertain impact of Access SCR.

83. Unfortunately, there are several elements to Ofgem's proposal which fall short.

84. In principle we agree with Ofgem's proposal to have a load-related re-opener, however there are elements within the design of the re-opener which will act as a barrier to delivery and need to be fixed.

85. We do not agree with Ofgem's proposed secondary reinforcement and LV services volume drivers and associated controls. Ofgem's proposals do not give DNOs the ability to deliver work needed beyond baseline LCT scenarios.

86. Firstly, there are two material unfunded outputs that need to be addressed:

    a. Indirect costs of higher demand scenarios; and

    b. Secondary network flexibility or smart solutions.

87. Secondly, there are potential barriers to investment that need to be resolved:

a. The re-opener must be agile to avoid the risk of backlogs being created and therefore delays to decisions;

b. The re-opener must be able to be triggered earlier if either a more aggressive demand scenario materialises, or the direct cost impact of Access SCR is above baseline; and

c. The overall cap on secondary reinforcement should never act as a barrier to decarbonisation.

88. Even after these problems are fixed, there remain fundamental gaps in the design of the mechanisms which require clarity.

a. Ofgem must be explicit as to the differences between the conditions that apply to funding up to the baseline of the volume drivers as opposed to funding over the baseline;

b. The mechanism to effectively control for the uncertain impact of Access SCR across all voltage levels requires clarity;

c. The detailed design of the utilisation monitoring metrics – and any consequences for allowances arising from performance against these - must be carefully considered; and

d. Ofgem needs to set out the scope of the volume driver mid-period review in advance.

Unfunded outputs: Indirect costs funding gap

89. For secondary reinforcement and LV services beyond baseline levels, Ofgem's proposals only release funding for the direct unit costs of the capital intervention. Any incremental engineering and associated business costs incurred to deliver higher capital interventions (beyond the baseline) are, therefore, not funded.

90. This is an error - it is a matter of common sense that delivering higher direct investment requires higher associated indirect costs. Quantified evidence of this is also clear in Ofgem's own analyses and reflected in regulatory precedent:

a. Ofgem's disaggregated regression analysis shows a positive and significant relationship between the level of indirect costs (i.e. Closely Associated Indirects and Business Support Costs) and Modern Equivalent Asset Value (MEAV). MEAV is a close proxy for the cumulative value of capital interventions and clearly delivering substantially higher investment scenarios implies a substantially larger business 'scale', for which MEAV is used as a proxy by Ofgem.

b. Evidence which Ofgem referred to in the RIIO-T1 and RIIO-ED1 re-openers shows that indirect costs account for up to approximately 20% of the total cost of electricity transmission line works.

c. Ofgem's 'DG incentive' mechanism from DPCR4 (also retained for DPCR5), which was set up to allow DNOs to recover costs associated with uncertain uptake of distributed generation, included a volume-driver based pass through of indirect costs attributable to DG connections.

91. This error will lead to a material funding shortfall. Based on the conservative assumption of 20% referred to in T1 and ED1, we estimate a shortfall of around £134m[1] under the CCC's Widespread Engagement Pathway. Clearly this funding gap will continue to increase in demand scenarios beyond that.

92. If this issue is not corrected for the Final Determination, we will not be able to deliver scenarios above the baseline. It is clear that this system would fail to meet Ofgem's stated intention to adopt agile uncertainty mechanisms to release sufficient funding that enables DNOs to react to higher demand scenarios.

93. For work beyond the baseline, indirect costs need to be incorporated into the volume drivers. This may be either by:

a. Defining an appropriate 'loading factor' i.e. a percentage uplift to be applied to the currently calculated direct unit costs used for the volume driver; or

b. Defining a separate and additional 'indirect unit cost' with an appropriate metric for determining when/how funding is released.

94. Of these two options, we consider the former would be the simplest and most efficient.

95. There are a range of options for how the indirect unit cost loading factor could be calculated.

a. A simple method would be to draw on the evidence Ofgem previously relied on (noted above). This implies an appropriate loading factor of 20%, since the efficient indirect costs for DNOs are higher than for transmission;

b. Ofgem could identify categories of indirect costs which are expected to vary with direct costs to estimate a ratio/relationship. For example, a simple ratio of closely associated indirects to direct activity (based on business plan submissions) implies a ratio of 24.4%. We propose to work with Ofgem to establish an appropriate approach ahead of the Final Determinations.

Unfunded outputs: Secondary network flexibility or smart solutions

96. Ofgem's secondary reinforcement volume drivers only fund traditional capital-based reinforcement. They do not provide any funding to DNOs to procure flexibility or invest in smart solutions at these lower voltage levels.

[1] This is based on 20:80 scaling factor applied to the difference in secondary load-related expenditure required to deliver CCC's Widespread Engagement Pathway compared to FES 2021 System Transformation Pathway (where indirect costs are funded in the ex-ante baseline indirect allowances). This is conservative given the higher share of indirect costs expected in electricity distribution compared to transmission.

97. In the context of Ofgem's requirements for a "flexibility first" approach and the potential significant scaling up of secondary reinforcement work in scenarios above the baseline, this cannot be correct. It is also an error for Ofgem to penalise DNOs who fail to explore flexibility through the penalty-only 'market test' component of the DSO incentive, while at the same time providing no funding (above the baseline) for DNOs to actually procure flexibility.

98. Ofgem acknowledges that the current approach "does not include a volume measure for flexibility spend on the lower voltages" and that it is important not to weaken incentives to procure flexibility. Despite this, Ofgem dismisses options to incorporate flexibility or smart solutions in the volume driver on the basis that this may over-remunerate DNOs.

99. Ofgem also appears to believe that other elements of the framework will compensate for this lack of funding, but Ofgem's reasoning is incorrect:

a. Ofgem suggests the DSO incentive will compensate for the lack of funding (para 3.62). However, this is incorrect. The DSO incentive is not designed to fund the deployment of flexibility, only to test whether flexibility could be deployed economically. In addition, the DSO incentive suffers from other problems (see our response to Core Q24 and Q25).

b. Ofgem suggests that applying TIM to spend through the volume driver will compensate for the lack of funding (para 3.63). Again, this is incorrect – allowances that flow through the volume driver are only granted if we do traditional reinforcement. If we procure flexibility, our allowance is zero. By definition this will mean DNOs will incur a loss each time they procure flexibility - even if this loss were moderated by the application of TIM, the system will still mean that procuring flexibility or smart solutions is always loss-making for the DNO. The volume driver is therefore geared solely to encourage DNOs to use traditional reinforcement, irrespective of TIM application.

100. Ultimately, without any funding for flexibility or smart solutions in higher scenarios above the baseline, customers will lose out. DNOs will be encouraged simply to roll out traditional solutions, even where more efficient alternatives might have been available. Customers will therefore inevitably face bills that are at least as high as those they would have faced under the flexibility volume-driver options that Ofgem has dismissed.

101. Moreover, there are appropriate solutions to this problem which mitigate the risk of over-remuneration, which appears to have been Ofgem's primary reason to provide no funding. The appropriate correction is two-fold.

102. Firstly, Ofgem should confirm that it is providing ex ante baseline allowances for secondary reinforcement (i.e. funding that is not conditional on a volume-driver or with risk of regulatory clawback). This gives the DNOs a clear incentive within the baseline scenario to find the most efficient solution - including procuring flexibility and/or installing smart solutions where it is efficient to do so, and optimise across voltages and between maintenance and replacement. In the short-term during ED2, the TIM and the broader Return Adjustment Mechanisms will protect customers from any underspend and enable them to share the benefits associated with

the strong incentive. Longer term, this is the best way to encourage the revelation of information around how and where these (still relatively new) solutions can be deployed, which can subsequently be baked into baseline allowances for ED3 and beyond.

103. This would also have the benefit of aligning to Ofgem's funding mechanism for connections-driven reinforcement, where they have provided ex ante baseline allowances.

104. Secondly, for secondary reinforcement requirements beyond the baseline, the funding mechanism should be adapted as follows.

a. At the secondary voltage levels, DNOs should be required to submit a calculation using the ENA Common Evaluation Methodology (CEM) tool, which Ofgem already requires DNOs to use for its DSO incentive, for flexibility (or a similar CBA tool for smart solutions). This standardised framework should be used to demonstrate that the alternative procured solution was an efficient decision at the time it was made.

b. DNOs should then receive a fast-money revenue allowance equal to the depreciation and return that would have accrued had the traditional capital investment been incurred (but which has now been deferred in time due to the use of flexibility/smart solutions).

c. This annual amount should be added to revenue allowances up until the point that the deferred investment is subsequently made, whenever that happens to be. At that point, the annual allowances should stop.

d. Importantly, this means that the ex ante assumption on how long the deferral was for will not influence the amount that customers pay. Alongside the highly transparent reporting using the CEM tool, this should substantially mitigate the "significant risk of gaming" Ofgem is concerned about (para 3.62).

105. We note that Ofgem's monitoring metrics should also offer further customer protection, albeit the design of these metrics needs to be considered carefully in the context of understanding the impact on incentives for flex and smart solutions.

106. Overall, we believe this system will correct Ofgem's current thinking by funding investment in flexibility and smart solutions where it is in customer interests, particularly in high-demand scenarios when flex is most likely to be valuable.

107. Given the application of the TIM to the difference between the allowances derived from the cost of the deferred investment and the cost of the flexible or smart solution, customers will pay less than the benefit they receive from deferring investment and will also benefit through enabling better information to set cost allowances in ED3 and beyond. Ultimately, under this system, customers in ED2 will at most pay as much as they would do anyway under Ofgem's DD proposal, and, in all likelihood, they will pay less.

108. If Ofgem does not set ex ante baseline secondary reinforcement allowances, this funding mechanism could also apply to the baseline funding.

The re-opener must be agile

109. As the re-opener is administrative, rather than automatic, it risks backlogs being created and therefore delays to decisions and ultimately to customers connecting and the country decarbonising.

110. We do not oppose Ofgem bringing forward the reopener window until the last week of January. The change to the timetable means that Ofgem will afford itself additional time for assessment, and also more time to obtain any additional information it thinks it may require to take decisions, which is positive. But Ofgem need to confirm how the process is going to be run in April 2025 and put strict timescales in place for Ofgem to respond to information submitted by DNOs. We note that Ofgem recently removed a clause in the licence which made re-opener responses timebound and which will increase the risk of delay.

111. Ofgem should not give itself the discretionary ability to reject reopener requests out of hand because it considers the application did not contain the information necessary to take an informed decision. Ofgem has the ability to ask for further information throughout the reopener process, along with its already extensive information gathering powers. It would be unreasonable and disproportionate for Ofgem to reject a reopener application because it subsequently decided the initial application did not contain all the information it wished. Ofgem should not contemplate this as to do so would lead it to fail in its duty to fund the efficient costs of licensees in undertaking their regulated business.

112. Ofgem should consider introducing an "updated submission" window, for revised submissions later in the process, perhaps around May. This would allow for the latest information to be introduced, along with any revisions to submissions that Ofgem's question and evaluation process has revealed is necessary, e.g. to aid comparability.

The re-opener trigger must be flexible

113. Ofgem should allow both DNOs and itself to be able to trigger the re-opener earlier if either a more aggressive demand scenario materialises, or the direct cost impact of Access SCR is above the baseline.

The cap on volume driver funding should never act as a barrier to decarbonisation

114. The cap – if it ever applied – would necessarily act as a barrier to decarbonisation. This would not be in the interest of consumers.

115. If Ofgem is going to retain the cap, it should make a clear policy statement now that, should LCT uptake require investment in excess of the cap; Ofgem will increase it accordingly.

116. Ofgem should set out in its FD what information it will take into account when it revisits the cap in year 3 and in the close-out process. For example, to what extent will the monitoring metrics be used in evaluating whether to lift the cap? Or will it be based purely on evidence of higher demand scenarios?

Detailed design of the ex post *utilisation monitoring metrics*

117. Clawback uncertainty surrounds the monitoring metrics as the DD has not provided enough information on the detailed design, and therefore destabilises investor confidence. Given that the metrics are high level, loose and imperfect, and Ofgem has confirmed that they can't be used mechanistically, the burden of proof required to dispute any potential claw back derived from the metrics needs to be clearly outlined upfront (and the hurdle must be a high one).

118. The detailed design of the ex post utilisation monitoring metrics must be carefully considered. The metrics must:

    a. Be tightly scoped and tested, with the tolerances being applied prescribed upfront;

    b. Ensure there is a route to incorporating local stakeholder need for strategic investment, without allowing for inefficient investment;

    c. Ensure there is an incentive for investment in flexibility and smart solutions;

    d. Cater for connections-driven reinforcement and impact of Access SCR; and

    e. Offer customer protections whilst not compromising investor confidence.

119. Ofgem asked for support from DNOs in development of the monitoring metrics through the load-related expenditure working group. We have been and will continue to actively participate.

Controlling for the uncertain impact of Access SCR

120. We agree with Ofgem's proposal not to introduce a specific uncertainty mechanism to manage the impact of the Access SCR. We do not believe the driver of the investment, Access SCR or otherwise, would be easily identifiable and therefore it would be a challenge to separate costs. Additionally, we agree that the driver of the investment is largely irrelevant, and it is more important that the need for new network investment is identified and funded.

121. Ofgem must provide clarity on the funding routes for the impact of Access SCR. Ofgem has provided ex ante baseline allowances for both primary and secondary connections-driven reinforcement; we agree with this approach as it gives the DNOs a clear incentive to find the most efficient solution. DNOs' share of indirect costs are funded in the ex ante indirect allowances. However, it remains unclear how Ofgem propose to fund any additional connections-driven reinforcement above this baseline. Ofgem should fund this additional investment for secondary reinforcement through the volume driver and for primary reinforcement through the re-opener. For secondary reinforcement, as detailed above, Ofgem must fund indirect costs and confirm whether connections-driven secondary reinforcement requires additional work units (i.e. different to the volume drivers provided for routine capital work).

122. Ofgem need to be cognisant that some connections-drive reinforcement may require additional cost (e.g. primary substation level) which are not covered by the volume drivers, these additional costs would need to be split out and funded through the re-opener.

Funding over the baseline

123. Ofgem must be explicit as to the differences between the conditions that apply to funding up to the baseline of the volume drivers as opposed to funding over the baseline. We understand that funding over the baseline will be subject to Ofgem's monitoring regime, and that where Ofgem has evidence that investments should not have been made, it may confiscate the related allowances retrospectively. Ofgem should be clear that the baseline expenditure is not subject to this mechanism, and the baseline allowances for secondary reinforcement act as a limit on clawback risk.

124. Ofgem must maintain the current position that the ex ante baseline allowance for primary reinforcement is not within the scope of the re-opener.

Mid-period review

125. Ofgem needs to set out the scope of the mid period review in advance. And – when doing so – Ofgem must be careful not to disincentive efficiency over the medium to long-term.

126. For example, Ofgem should be explicit that it will not ratchet away unit cost efficiencies achieved in the first part of ED2.

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

127. Ofgem took a decentralised approach to determining demand forecasts; as a result, companies based their plans on a wide range of very different decarbonisation scenarios. To try and control for these inconsistent and therefore incomparable inputs, Ofgem replaced those scenarios with a common low scenario (FES 2021 System Transformation). Consequently, the baseline cost allowances were built on an uptake in LCTs that represents the lowest level of decarbonisation that is still consistent with the government's legally binding target for net zero carbon emissions by 2050. This means it is likely higher demand scenarios will materialise and having a mechanism to cater for any additional investment which reacts in an agile, flexible manner is essential. The potential need for a material increase in investment above Ofgem's baseline funding will be further compounded by the impact of Access SCR.

128. Ofgem has proposed an LRE 'toolkit' comprised of automatic and administrative mechanisms aimed at allowing investment to dial up in response to new demand, including a:

   a. Secondary reinforcement volume driver (automatic);

   b. LV services volume driver (automatic); and

   c. Re-opener for all other load-related expenditure not covered by a volume driver (administrative).

129. A workable solution must:

a. Never act as a barrier to delivery in higher demand scenarios;

b. Fund and incentivise investment in network flexibility and smart solutions; or

c. Effectively control for the uncertain impact of Access SCR.

130. Unfortunately, there are several elements to Ofgem's proposal which fall short.

131. In principle we agree with Ofgem's proposal to have a load-related re-opener, however there are elements within the design of the re-opener which will act as a barrier to delivery and need to be fixed.

132. We do not agree with Ofgem's proposed secondary reinforcement and LV services volume drivers and associated controls. Ofgem's proposals do not give DNOs the ability to deliver work needed beyond baseline LCT scenarios.

133. Firstly, there are two material unfunded outputs that need to be addressed:

a. Indirect costs of higher demand scenarios; and

b. Secondary network flexibility or smart solutions.

134. Secondly, there are potential barriers to investment that need to be resolved:

a. The re-opener must be agile to avoid the risk of backlogs being created and therefore delays to decisions;

b. The re-opener must be able to be triggered earlier if either a more aggressive demand scenario materialises, or the direct cost impact of Access SCR is above baseline; and

c. The overall cap on secondary reinforcement should never act as a barrier to decarbonisation.

135. Even after these problems are fixed, there remain fundamental gaps in the design of the mechanisms which require clarity.

a. Ofgem must be explicit as to the differences between the conditions that apply to funding up to the baseline of the volume drivers as opposed to funding over the baseline;

b. The mechanism to effectively control for the uncertain impact of Access SCR across all voltage levels requires clarity;

c. The detailed design of the utilisation monitoring metrics – and any consequences for allowances arising from performance against these - must be carefully considered; and

d. Ofgem needs to set out the scope of the volume driver mid-period review in advance.

Unfunded outputs: Indirect costs funding gap

136. For secondary reinforcement and LV services beyond baseline levels, Ofgem's proposals only release funding for the direct unit costs of the capital intervention. Any incremental engineering and associated business costs incurred to deliver higher capital interventions (beyond the baseline) are, therefore, not funded.

137. This is an error - it is a matter of common sense that delivering higher direct investment requires higher associated indirect costs. Quantified evidence of this is also clear in Ofgem's own analyses and reflected in regulatory precedent:

    a. Ofgem's disaggregated regression analysis shows a positive and significant relationship between the level of indirect costs (i.e. Closely Associated Indirects and Business Support Costs) and Modern Equivalent Asset Value (MEAV). MEAV is a close proxy for the cumulative value of capital interventions and clearly delivering substantially higher investment scenarios implies a substantially larger business 'scale', for which MEAV is used as a proxy by Ofgem.

    b. Evidence which Ofgem referred to in the RIIO-T1 and RIIO-ED1 re-openers shows that indirect costs account for up to approximately 20% of the total cost of electricity transmission line works.

    c. Ofgem's 'DG incentive' mechanism from DPCR4 (also retained for DPCR5), which was set up to allow DNOs to recover costs associated with uncertain uptake of distributed generation, included a volume-driver based pass through of indirect costs attributable to DG connections.

138. This error will lead to a material funding shortfall. Based on the conservative assumption of 20% referred to in T1 and ED1, we estimate a shortfall of around £134m [2] under the CCC's Widespread Engagement Pathway. Clearly this funding gap will continue to increase in demand scenarios beyond that.

139. If this issue is not corrected for the Final Determination, we will not be able to deliver scenarios above the baseline. It is clear that this system would fail to meet Ofgem's stated intention to adopt agile uncertainty mechanisms to release sufficient funding that enables DNOs to react to higher demand scenarios.

140. For work beyond the baseline, indirect costs need to be incorporated into the volume drivers. This may be either by:

    a. Defining an appropriate 'loading factor' i.e. a percentage uplift to be applied to the currently calculated direct unit costs used for the volume driver; or

[2] This is based on 20:80 scaling factor applied to the difference in secondary load-related expenditure required to deliver CCC's Widespread Engagement Pathway compared to FES 2021 System Transformation Pathway (where indirect costs are funded in the ex-ante baseline indirect allowances). This is conservative given the higher share of indirect costs expected in electricity distribution compared to transmission.

b. Defining a separate and additional 'indirect unit cost' with an appropriate metric for determining when/how funding is released.

141. Of these two options, we consider the former would be the simplest and most efficient.

142. There are a range of options for how the indirect unit cost loading factor could be calculated.

a. A simple method would be to draw on the evidence Ofgem previously relied on (noted above). This implies an appropriate loading factor of 20%, since the efficient indirect costs for DNOs are higher than for transmission;

b. Ofgem could identify categories of indirect costs which are expected to vary with direct costs to estimate a ratio/relationship. For example, a simple ratio of closely associated indirects to direct activity (based on business plan submissions) implies a ratio of 24.4%. We propose to work with Ofgem to establish an appropriate approach ahead of the Final Determinations.

Unfunded outputs: Secondary network flexibility or smart solutions

143. Ofgem's secondary reinforcement volume drivers only fund traditional capital-based reinforcement. They do not provide any funding to DNOs to procure flexibility or invest in smart solutions at these lower voltage levels.

144. In the context of Ofgem's requirements for a "flexibility first" approach and the potential significant scaling up of secondary reinforcement work in scenarios above the baseline, this cannot be correct. It is also an error for Ofgem to penalise DNOs who fail to explore flexibility through the penalty-only 'market test' component of the DSO incentive, while at the same time providing no funding (above the baseline) for DNOs to actually procure flexibility.

145. Ofgem acknowledges that the current approach "does not include a volume measure for flexibility spend on the lower voltages" and that it is important not to weaken incentives to procure flexibility. Despite this, Ofgem dismisses options to incorporate flexibility or smart solutions in the volume driver on the basis that this may over-remunerate DNOs.

146. Ofgem also appears to believe that other elements of the framework will compensate for this lack of funding, but Ofgem's reasoning is incorrect:

a. Ofgem suggests the DSO incentive will compensate for the lack of funding (para 3.62). However, this is incorrect. The DSO incentive is not designed to fund the deployment of flexibility, only to test whether flexibility could be deployed economically. In addition, the DSO incentive suffers from other problems (see our response to Core Q24 and Q25).

b. Ofgem suggests that applying TIM to spend through the volume driver will compensate for the lack of funding (para 3.63). Again, this is incorrect – allowances that flow through the volume driver are only granted if we do traditional reinforcement. If we procure flexibility, our allowance is zero. By definition this will mean DNOs will incur a loss each time they procure flexibility - even if this loss were moderated by the application of TIM, the system will still mean that procuring flexibility or smart solutions is always loss-making for the DNO. The volume driver is therefore geared solely to encourage DNOs to use traditional reinforcement, irrespective of TIM application.

147. Ultimately, without any funding for flexibility or smart solutions in higher scenarios above the baseline, customers will lose out. DNOs will be encouraged simply to roll out traditional solutions, even where more efficient alternatives might have been available. Customers will therefore inevitably face bills that are at least as high as those they would have faced under the flexibility volume-driver options that Ofgem has dismissed.

148. Moreover, there are appropriate solutions to this problem which mitigate the risk of over-remuneration, which appears to have been Ofgem's primary reason to provide no funding. The appropriate correction is two-fold.

149. Firstly, Ofgem should confirm that it is providing ex ante baseline allowances for secondary reinforcement (i.e. funding that is not conditional on a volume-driver or with risk of regulatory clawback). This gives the DNOs a clear incentive within the baseline scenario to find the most efficient solution - including procuring flexibility and/or installing smart solutions where it is efficient to do so, and optimise across voltages and between maintenance and replacement. In the short-term during ED2, the TIM and the broader Return Adjustment Mechanisms will protect customers from any underspend and enable them to share the benefits associated with the strong incentive. Longer term, this is the best way to encourage the revelation of information around how and where these (still relatively new) solutions can be deployed, which can subsequently be baked into baseline allowances for ED3 and beyond.

150. This would also have the benefit of aligning to Ofgem's funding mechanism for connections-driven reinforcement, where they have provided ex ante baseline allowances.

151. Secondly, for secondary reinforcement requirements beyond the baseline, the funding mechanism should be adapted as follows.

   a. At the secondary voltage levels, DNOs should be required to submit a calculation using the ENA Common Evaluation Methodology (CEM) tool, which Ofgem already requires DNOs to use for its DSO incentive, for flexibility (or a similar CBA tool for smart solutions). This standardised framework should be used to demonstrate that the alternative procured solution was an efficient decision at the time it was made.

   b. DNOs should then receive a fast-money revenue allowance equal to the depreciation and return that would have accrued had the traditional capital investment been incurred (but which has now been deferred in time due to the use of flexibility/smart solutions).

   c. This annual amount should be added to revenue allowances up until the point that the deferred investment is subsequently made, whenever that happens to be. At that point, the annual allowances should stop.

d. Importantly, this means that the ex ante assumption on how long the deferral was for will not influence the amount that customers pay. Alongside the highly transparent reporting using the CEM tool, this should substantially mitigate the “significant risk of gaming” Ofgem is concerned about (para 3.62).

152. We note that Ofgem’s monitoring metrics should also offer further customer protection, albeit the design of these metrics needs to be considered carefully in the context of understanding the impact on incentives for flex and smart solutions.

153. Overall, we believe this system will correct Ofgem’s current thinking by funding investment in flexibility and smart solutions where it is in customer interests, particularly in high-demand scenarios when flex is most likely to be valuable.

154. Given the application of the TIM to the difference between the allowances derived from the cost of the deferred investment and the cost of the flexible or smart solution, customers will pay less than the benefit they receive from deferring investment and will also benefit through enabling better information to set cost allowances in ED3 and beyond. Ultimately, under this system, customers in ED2 will at most pay as much as they would do anyway under Ofgem’s DD proposal, and, in all likelihood, they will pay less.

155. If Ofgem does not set ex ante baseline secondary reinforcement allowances, this funding mechanism could also apply to the baseline funding.

The re-opener must be agile

156. As the re-opener is administrative, rather than automatic, it risks backlogs being created and therefore delays to decisions and ultimately to customers connecting and the country decarbonising.

157. We do not oppose Ofgem bringing forward the reopener window until the last week of January. The change to the timetable means that Ofgem will afford itself additional time for assessment, and also more time to obtain any additional information it thinks it may require to take decisions, which is positive. But Ofgem need to confirm how the process is going to be run in April 2025 and put strict timescales in place for Ofgem to respond to information submitted by DNOs. We note that Ofgem recently removed a clause in the licence which made re-opener responses timebound and which will increase the risk of delay.

158. Ofgem should not give itself the discretionary ability to reject reopener requests out of hand because it considers the application did not contain the information necessary to take an informed decision. Ofgem has the ability to ask for further information throughout the reopener process, along with its already extensive information gathering powers. It would be unreasonable and disproportionate for Ofgem to reject a reopener application because it subsequently decided the initial application did not contain all the information it wished. Ofgem should not contemplate this as to do so would lead it to fail in its duty to fund the efficient costs of licensees in undertaking their regulated business.

159. Ofgem should consider introducing an "updated submission" window, for revised submissions later in the process, perhaps around May. This would allow for the latest information to be introduced, along with any revisions to submissions that Ofgem's question and evaluation process has revealed is necessary, e.g. to aid comparability.

The re-opener trigger must be flexible

160. Ofgem should allow both DNOs and itself to be able to trigger the re-opener earlier if either a more aggressive demand scenario materialises, or the direct cost impact of Access SCR is above the baseline.

The cap on volume driver funding should never act as a barrier to decarbonisation

161. The cap – if it ever applied – would necessarily act as a barrier to decarbonisation. This would not be in the interest of consumers.

162. If Ofgem is going to retain the cap, it should make a clear policy statement now that, should LCT uptake require investment in excess of the cap; Ofgem will increase it accordingly.

163. Ofgem should set out in its FD what information it will take into account when it revisits the cap in year 3 and in the close-out process. For example, to what extent will the monitoring metrics be used in evaluating whether to lift the cap? Or will it be based purely on evidence of higher demand scenarios?

Detailed design of the ex post *utilisation monitoring metrics*

164. Clawback uncertainty surrounds the monitoring metrics as the DD has not provided enough information on the detailed design, and therefore destabilises investor confidence. Given that the metrics are high level, loose and imperfect, and Ofgem has confirmed that they can't be used mechanistically, the burden of proof required to dispute any potential claw back derived from the metrics needs to be clearly outlined upfront (and the hurdle must be a high one).

165. The detailed design of the ex post utilisation monitoring metrics must be carefully considered. The metrics must:

a. Be tightly scoped and tested, with the tolerances being applied prescribed upfront;

b. Ensure there is a route to incorporating local stakeholder need for strategic investment, without allowing for inefficient investment;

c. Ensure there is an incentive for investment in flexibility and smart solutions;

d. Cater for connections-driven reinforcement and impact of Access SCR; and

e. Offer customer protections whilst not compromising investor confidence.

166. Ofgem asked for support from DNOs in development of the monitoring metrics through the load-related expenditure working group. We have been and will continue to actively participate.

Controlling for the uncertain impact of Access SCR

167. We agree with Ofgem's proposal not to introduce a specific uncertainty mechanism to manage the impact of the Access SCR. We do not believe the driver of the investment, Access SCR or otherwise, would be easily identifiable and therefore it would be a challenge to separate costs. Additionally, we agree that the driver of the investment is largely irrelevant, and it is more important that the need for new network investment is identified and funded.

168. Ofgem must provide clarity on the funding routes for the impact of Access SCR. Ofgem has provided ex ante baseline allowances for both primary and secondary connections-driven reinforcement; we agree with this approach as it gives the DNOs a clear incentive to find the most efficient solution. DNOs' share of indirect costs are funded in the ex ante indirect allowances. However, it remains unclear how Ofgem propose to fund any additional connections-driven reinforcement above this baseline. Ofgem should fund this additional investment for secondary reinforcement through the volume driver and for primary reinforcement through the re-opener. For secondary reinforcement, as detailed above, Ofgem must fund indirect costs and confirm whether connections-driven secondary reinforcement requires additional work units (i.e. different to the volume drivers provided for routine capital work).

169. Ofgem need to be cognisant that some connections-drive reinforcement may require additional cost (e.g. primary substation level) which are not covered by the volume drivers, these additional costs would need to be split out and funded through the re-opener.

Funding over the baseline

170. Ofgem must be explicit as to the differences between the conditions that apply to funding up to the baseline of the volume drivers as opposed to funding over the baseline. We understand that funding over the baseline will be subject to Ofgem's monitoring regime, and that where Ofgem has evidence that investments should not have been made, it may confiscate the related allowances retrospectively. Ofgem should be clear that the baseline expenditure is not subject to this mechanism, and the baseline allowances for secondary reinforcement act as a limit on clawback risk.

171. Ofgem must maintain the current position that the ex ante baseline allowance for primary reinforcement is not within the scope of the re-opener.

Mid-period review

172. Ofgem needs to set out the scope of the mid period review in advance. And – when doing so – Ofgem must be careful not to disincentive efficiency over the medium to long-term.

173. For example, Ofgem should be explicit that it will not ratchet away unit cost efficiencies achieved in the first part of ED2.

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

174. Yes, we agree with the proposal in principle. In its design, it needs to be scoped in a focused manner in order that investor confidence is not adversely impacted providing upward pressure on the cost of equity.

175. The reopener should be limited to change in efficient expenditure necessary as a result of the change in legislation or policy.

176. The trigger should be tightly ringfenced to major shifts in government policy or legislation, such as a change in the 2050 date for the net-zero target.

177. It must not be a route to continually “fine tune” the price control settlement, which would fundamentally undermine the incentives that drive improved outcomes.

178. The onus placed on network companies by RIIO to manage the costs of the low-carbon transition should be maintained.

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

179. This approach appears reasonable at this time.

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

180. We are generally content with the proposed approach to the NIA benchmarking and SSMD weighting and we do not believe that further weighting should be given to the rollout of innovation in the five NIA criteria such that it further reduces the NIA award.

181. Ofgem asserts “in response to our recent request, NPg did not provide evidence, such as in the form of models, that these estimates were based on a robust process”.

182. There is no record of this request in the supplementary questions received by Northern Powergrid.

183. We did receive an informal request for innovation information which we responded to including providing an in-depth analysis of innovation benefits. We note that this informal request, which we received initially through another DNO and not directly from Ofgem, was not part of Ofgem’s official process for supplementary questions in the regulatory review.

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

184. Given that the benefits of a given innovation ought to be in line with the overall required investment, yet the cost of developing that innovation is likely to be the same to any DNO, it is likely that the cost benefit analysis for innovation will favour larger DNO groups.

185. It is unfortunate therefore that Ofgem has chosen a model which awards greater allowances to larger DNO groups, thereby promoting a bias in innovation towards the larger DNO groups.

186. We would therefore support an approach that gives consideration to a flat sum NIA allowance for each DNO group, rather than the proposed percentage of overall allowances.

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

187. This proposal appears reasonable.

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

188. We agree with the proposed approach for the AER ODI-R.

189. It allows for increased transparency and awareness of the impact our activities have on the environment and our actions and plans to manage risks, improve performance and decarbonise.

190. A common format for the report will be required and as outlined on paragraph 3.142 of the core methodology document; we look forward to working with Ofgem on that format.

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

191. We do not agree that a mid-period review on environmental performance and progress to targets is necessary to supplement the annual reporting requirement. At this stage it is unclear as to how this is different from the annual reporting on performance against targets and what additional value Ofgem would derive from it for customers.

192. We believe annual reviews are sufficient and the proposal for an ODI-R allows for increased transparency and awareness of the impact our activities have on the environment and our actions and plans to manage risks, improve performance and decarbonise. The DNOs will be issuing an AER to report against their plan so this should be sufficient to track performance over the period.

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

193. We acknowledge that Ofgem has accepted DNO Environmental Action Plan commitments that will lead to a significant improvement in environmental performance. We would therefore expect that Ofgem funds the efficient investment required to deliver these improvements in the final determination.

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

194. We agree with the proposal to withdraw the environmental scorecard ODI-F.

195. We believe the ODI-R is sufficient incentive to drive performance. Our obligations under the AER are the appropriate driver to reduce environmental impacts arising from our activities and facilitate decarbonisation of our operations.

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

196. We agree with the proposed approach to the design of the environmental re-opener.

197. We agree with the scope of the environmental re-opener and would emphasise that it should only be instigated to accommodate legislative changes that require a material change in our Environmental Action Plan.

198. We would propose that Ofgem consider that the trigger mechanism is extended from "Authority triggered only" to "DNO and Authority tiggered". This is to account for any material changes that may occur within a DNO's specific region or changes the DNOs consider to be material and significant. For example, we are currently unclear on the significance or impact of the Environment Agency proposed move to electronic waste management and carrier permitting, or the impact that the repeal of RPS 211 (excavated spoil) will have.

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

199. We agree with the proposal for addressing PCB contamination in PMTs through a volume driver in RIIO-ED2.

200. We agree with Ofgem on the need for the design of the volume driver to accommodate asset upsizing which will reduce network losses and enable low-cost capacity for the net zero transition. This approach should be common across all DNOs.

201. We don't agree with the need for a sunset clause due to global uncertainties on equipment provision and any changes in interpretation of the requirement by the Environmental Agency.

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

202. Yes, we agree with the proposal to implement a digitalisation license obligation.

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

203. Yes, we agree with the proposal to have staggered publications of Digitalisation Strategies between RIIO-ED2 and RIIO-2 licensees.

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

204. Yes, we agree with the proposal.

205. The re-opener should be used only where the licensee incurs or expects to incur additional costs due to a shift in roles and responsibilities (as per Annex 1 Draft Special Conditions, para 3.2.52).

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

206. Yes, we agree with the proposed enhanced reporting framework associated with IT/OT Data and Digitalisation spend and DSAP investment proposals.

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

207. Yes, we agree with the proposal to adopt Technology Business Management as part of the RIGs/RRP, provided that we are given clear guidance on what is to be included in the scope of TBM/RRP.

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

208. We are supportive of the intention to move to a more modernised regulatory reporting process which provides Ofgem with the information it requires on a timely basis at the same time as streamlining existing requirements.

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

209. It seems appropriate that the project should be started as soon as the ED2 price control has been agreed as it will take time to ensure successful implementation. We are supportive of the aim to have this finalised by the end of the third year of ED2.

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

210. Ofgem needs to place more weight on the mainstream price control incentives and less weight on the standalone DSO incentive. The DSO incentive is too heavily weighted towards subjective judgements by either stakeholders or the performance panel (total of 80% weighting).

211. If DNOs are performing DSO functions effectively then this will be evident in the mainstream price control incentives. In particular:

   a. The totex incentive mechanism – where incentives are equalised such that network and non-network solutions may compete.

   b. Customer service incentive – that will measure the level of service for customers installing low carbon technologies.

212. It is appropriate to monitor and reward/penalise the delivery of other DSO actions by DNOs such as delivery of whole system benefits (e.g. reducing ESO balancing costs) or provision of open data. However, the financial value placed on these incentives should be in proportion to the ability to objectively assess delivery against customer need.

213. Customers benefit from the ability of Ofgem and stakeholders to compare between network companies. Having one incentive mechanism across all DNOs naturally means that those making the judgements of performance will be making comparisons as opposed to individual assessments. This is a strength of price control reviews as comparative benchmarking enables Ofgem to overcome information asymmetry and make decisions on an objective basis. However, this requires deep scrutiny. The stakeholder survey and performance panel assessments are unlikely to provide a sufficiently detailed assessment to be objective where delivery of DSO functions is linked to each individual company's customer or system requirements. As such it is impossible to say with confidence that the outcome is fully justified.

214. With this in mind, the 80% of weighting attributed to the more subjective judgements as detailed above should be reduced and the weighting of the metrics increased. Further, the proposed level of +/-£3m p.a. should also be reduced.

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

215. In principle, these are the right metrics and Regularly Reported Evidence (RRE). There are details that need changing to ensure that the metrics measure the outcomes that are of value for customers and avoid inappropriate or perverse consequences.

216. As Ofgem states, the metrics have resulted from a significant amount of discussion in working groups in which we have participated. This led to an effective choice of metrics that incentivise companies to deliver outcomes that are of value and recognise the state of evolution of the DSO functions.

217. It is important that the design of metrics and RRE deliver the following principles:

    a. outcomes that are of value to customers;

    b. outcomes that are under the control of companies to deliver; and

    c. that it is clear what a good outcome entails (e.g., a higher score is a better outcome).

218. Turning to the detail, we have specific comments on each metric.

Flexibility market testing

219. This is a good metric since it meets all three criteria identified above.

220. We do not support reinforcement decisions on the EHV/HV network being grouped with the LV system decisions. The ability to use flexibility is at different levels of maturity in each area, the availability of the data, and volume of activity to support flexibility at LV need to be considered.

221. Distribution Network Options Assessment (DNOA) needs to be defined before it can be used in the metric (though we note this reference is removed in subsequent information provided). For example, if the Common Evaluation Methodology demonstrates that flexibility is not economically viable companies should be able to transparently report this to the market and avoid the waste of time and effort (network companies and flexibility service providers) of dogmatically tendering for services that will never be fulfilled. We note the discussion of a materiality threshold in the DSO incentive workshop and support further consideration of how this could be applied.

222. Finally, there is no justification for this being a penalty only metric. As stated, there is a need to incentivise LV flexibility at scale as well as encourage higher volumes of flexibility by service providers. Setting this as penalty only does not incentivise behaviours beyond a 'compliance only' mindset.

Network visibility

223. This meets most of the criteria above. There is an open question on the ability of the national smart meter system to provide the same quality of service to northern DNOs due to the performance of the communication system that relies on a different technology. This does not invalidate the choice of metric. It simply needs to be borne in mind when setting targets for companies.

224. We support the recognition that low voltage network visibility will be provided from three sources: monitoring fitted at substations (potentially reporting on aggregated blocks of approximately 250-400 customers), smart meter data and use of techniques to infill the data gaps where it is not economically viable or technically possible to obtain the data.

225. If the metric is formed from a summation of all three sources, then it should be recognised that the three offer very different levels of data accuracy and insight. Though we note that in the subsequent information provided, Ofgem proposes to remove smart metering and modelling data from the metric, which we support.

226. A title of 'local network visibility' would be more appropriate since this metric is reporting on the monitoring of the low voltage network.

Curtailment efficiency

227. The application of this metric should be applied to those customers connected on non-firm connections after April 2023 where the customer has been provided with a guaranteed level beyond which they will not be curtailed (in line with the Access Significant Code Review decision).

228. If it were to be applied to any other form of non-firm connection, then these need to be carefully defined and the implications understood.

    a. The value of the incentive for these different customers would need to be understood in line with the criteria set out above.

    b. They may require extra monitoring and systems to be installed that would require funding as retrospective application was not included in business plans.

229. The metric would arguably work better if MVAh were used on both the nominator and denominator. We note the discussion in the DSO incentive workshop regarding the equation and that it may require updates.

230. The RRE are suitable to inform the judgement of the performance panel. As addressed in question 24, it needs to recognise that there may be differences in the RRE between companies that are not a reflection of the performance of companies. For example, for RRE 2, does a higher amount of distribution connected assets providing balancing services to the ESO mean that the DNO is doing better when compared between companies (or year to year within a company)?

231. This is one reason why we advocate that the performance panel weighting on the DSO incentive financial outcome is diminished. There is too much potential for judgements being made that will arbitrarily reward or penalise companies.

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

232. Yes, we agree with the proposal in principle. In its design, it needs to be scoped in a focused manner in order that investor confidence is not adversely impacted providing upward pressure on the cost of equity.

233. The focus of this re-opener needs to be clearly identified as resultant on outcomes from the Future of local energy institutions and governance review.

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

234. No. We are supportive of the direction of Ofgem's thinking and recognise the likely benefits from taking a whole system approach to planning. The outcomes being targeted are appropriate. However, the reporting obligation is disproportionate and duplicates existing activities. Right sizing this obligation will be important to make it both sufficiently ambitious to deliver value while being practically deliverable.

235. The information provided by Ofgem at this stage is not sufficient to support the proposal for introducing a licence obligation.

236. Putting an obligation on DNOs to co-ordinate a more robust approach is only one aspect of enabling a whole systems approach to decarbonisation and energy planning. There should be a comparable duty to co-operate for the other utilities and public sector. Additionally, if the obligation only extends to justifying DNO decisions, it will not facilitate a whole systems approach.

237. Having an additional separate report is disproportionate. It risks making the price control more inaccessible to stakeholders as it proliferates the amount of in-period reporting, and it adds extra costs that are borne by customers.

238. We already produce regular publications that transparently take a whole system view on planning. These are informed by engagement with a wide range of stakeholders, for example, Distribution Future Energy Scenarios (DFES), Whole Energy System Co-ordination Register (WESCo), Network Development Plan (NDP) and Long-Term Development Statement (LTDS). This engagement includes investment plans, planned activities, as well as decarbonisation pathway preferences of our stakeholders.

239. There needs to be a review of where there are potential reporting synergies, routes to reduce the overall volume for stakeholders and also the frequency of reporting (e.g., do planning methodologies require update annually?).

240. We already seek synergies by working collaboratively with utilities, businesses, charities, and local governments, among other organisations, where practically possible and regularly engage with a broad range of stakeholders representing different energy vectors and energy needs. Our

response to this question is informed by engagement with regional stakeholders, in particular feedback received from the Northeast & Yorkshire Net Zero Hub.

241. Making whole systems decisions and assessments would be reliant on availability of information and certainty of decisions, or actions, by multiple parties.

242. We expect that robust co-ordination with other organisations will materialise through the development of Local Area Energy Plans, which will be owned and governed by local government with the appropriate democratic mandate and decision-making powers.

243. It is unclear how whole systems benefits (and any associated conflicts of interest) should be measured, assessed and agreed where costs and benefits are borne by different entities. And if cost, carbon reduction, and other benefits carry an equal weighing in deciding what is 'optimal' outcome. Deciding on actions that achieve social efficiency is within the remit of the Government.

244. We are more positive about the digitalisation proposal. Issuing data on inputs and outputs for whole system planning in a common format would be valuable for different types of stakeholders. There is also opportunity to expand this into other networks in the future (e.g., gas and/or heat networks).

245. This is a relatively new proposal from Ofgem. As the activity is better understood then funding also needs to be considered.

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

246. We believe that digital tools are a vital enabler for the whole energy system. Because of this we have identified a number of digitalisation initiatives in the Data & Digitalisation section of our ED2 plan that will provide a set of digital tools capable of improving the planning, design, and operation of our distribution network and will be capable of interfacing and interoperating with customer flexibility assets and other actors.

247. Data will be critical to delivering a whole energy system and will need a modern set of digital tools to gather, store, interrogate and interpret data through advanced analytics. These tools will be needed to enable enhanced network modelling capabilities and make probabilistic based decisions that will allow consideration to be given to the whole energy system.

248. Modern digital tools will allow energy network issues and constraints to be identified well ahead of time, and mitigated through data driven informed choices, for example, flexibility supplied by consumers.

249. A modern set of digital tools and the sharing of energy system data in a common standard will release value for both ourselves and our external stakeholders, helping deliver a whole systems approach to planning and will support sector performance as a whole.

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

250. No, we do not agree. We believe the satisfaction level at which the reward can be accessed is set too high. It is considerably higher than other customer service organisations, so the majority

of DNOs (based on current performance which has increased significantly during RIIO-ED1) may not achieve the levels required to realise an incentive in RIIO-ED2.

251. The main benefit of BMCS is that it sets stretching targets which encouraged DNOs to continuously improve, there is a risk that by setting the target so high DNOs may opt not to invest further in customer satisfaction as the costs will outweigh the benefits when strong customer service is already being delivered.

252. We do, however, agree on the penalty levels set and believe this represents an improvement on the current position and incentivises DNOs to provide a continued good level of customer service.

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

253. Yes, we agree with the proposed approach to work with DNOs to implement Storm Arwen actions related to customer satisfaction. However, we do not expect there to be an impact on BMCS targets. There may, however, be some amendments in the RIGs to reflect any learning.

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

254. The target score is reasonable and seeks to ensure that customer satisfaction performance is maintained however, there is little incentive to progress. A reward score beginning at 9.2 is extremely ambitious when compared with other customer service industries and the current outlook for the energy market.

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

255. We agree with the proposal to remove baseline allowances for a DNO to directly deliver the three stated activities of repairing and replacing boilers, advisory workshops with customers and installing energy efficiency measures. Our colleagues will be trained in recognising a need and referring customers to our partners who will deliver advice and support on energy efficiency, low carbon technology and digital skills.

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

256. We agree with both the overall value assigned and the frequency of the assessment.

257. We believe July is the best timing for the assurance process to line up with year-on-year performance assessment and target setting as well as reporting on previous winter preparedness and forthcoming plans.

258. We agree with the minimum standards of the independent assessment but with further clarification of the detail around the data cleanse activity, in particular assurance of commonality of approach across DNOs.

259. We would welcome more structure and clarity around the form of the independent assessment, for example the format e.g. site visits, written submission, timing etc and that this is completed and shared as early as possible.

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

260. We agree with the defined performance metrics to be included in the incentive. We do not, however, agree with the targets and associated performance caps and penalty collars for all areas. We believe there are some fundamental areas that need adapting for the incentive to be successful.

261. Commonality of data sets used within PSR reach calculations and ensuring that we are using the latest available data to identify vulnerable customers across all the DNOs is essential. Furthermore, any data refresh should be appropriately timed within the assessment cycle.

262. The data cleanse principles within the CV ODI-R assurance assessment need to be clearly defined to ensure consistent application across the DNOs. This should include the treatment of incoming supplier data flows and subsequent route through data cleansing or automatic removal.

263. We agree with the use of NPV for measurement of both fuel poverty and Low Carbon Technology (LCT) services. However, as all DNOs have put in assumptive measures around benefits for these largely untested LCT services, we would welcome the opportunity to review and refresh these targets as different service models are delivered and tested giving us stronger verifiable proxies. Our preference would be an annual review and refresh or something in line with the assurance at years 2 and 5 across the DNOs.

264. Clarification as to what is included as direct services and the associated measurements will be integral to the success of the incentive. We are concerned that the incentive will drive DNOs towards delivery of lighter touch telephony and self-serve options in order to meet stated NPV, rather than the more complex direct services which are more costly but experience has shown are needed by customers.

265. We would suggest a 35% weighting towards fuel poverty and 25% weighting for LCT support within this incentive. The current equal weighting of 30% for both fuel poverty and LCT services does not recognise the fact that LCT services for vulnerable customers are largely untested, whereas fuel poverty services are embedded with strong benefits measurement in place. We also recognise the crossover between these two services of energy efficiency advice and in light of the current cost of living crisis believe there will be more demand from customers for fuel poverty services.

266. Our fuel poverty services are delivered through third-sector partners and this is likely to be the case for LCT services. Whilst we agree in principle with Ofgem that consumers should receive a consistently high standard of service they also state that these are new CSAT surveys for RIIO-ED2 with no historical data to inform a baseline target. Using the PSR satisfaction targets as the benchmark may on initial assessment appear to make sense but there are issues and assumptions that this does not consider:

a. PSR customers may also be experiencing fuel poverty but this is not currently a needs code so the cross over between service recipients may not be as clear as currently assumed.

b. PSR services are a core part of our business largely delivered directly by our colleagues whereas these services are delivered out of our direct control.

c. Our partners like Citizens Advice offer an excellent service for customers experiencing fuel poverty; often dealing with multiple issues across complex cases. Their reported satisfaction rates for these services is 84-85%.

d. LCT services are brand new and untested, very few new services could strive to achieve these levels of satisfaction from the off, in and out of regulated utilities.

267. We are concerned about driving overly ambitious commercial targets through third sector organisations who are already struggling with funding and their own running costs.

268. With this in mind we welcome the collar of 85% but propose that, rather than averaging the first 2 years scores for assurance, at year 2, we use the satisfaction end point to give us time to work with our partners to improve. We then propose using the average from years 3 to 5.

269. Furthermore, we propose reducing the satisfaction performance cap to bring them in line with the targets in the broader measure of customer satisfaction.

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

270. We agree with the proposal and welcome the opportunity to update both the regulator and our stakeholders on an annual basis.

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

271. We agree with the proposed content of the annual report.

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

272. A reward and penalty limit of +/-50% seems reasonable.

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

273. Given the context of the Access and Forward-looking Charges Significant Code Review and the changes in connection types and volumes that might occur as the energy system transitions it seems reasonable to have a dead band.

274. A dead band of +/-20% is reasonable in light of the +/-50% overall limits.

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

275. Noting our comments on target setting and the shape of the incentive in question Core-Q40, the general design of the Major Connections incentive is reasonable.

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

276. The targets and the target setting approach are still being discussed at the major connections working groups. The basis for these high targets seems to be the upper bounds of the DNOs' submitted targets; it is wrong to set these aspirational targets as the baseline below which a penalty would be applied. This is particularly inappropriate given there is no track record of measuring performance in this way for major connections customers. We welcome Ofgem's recognition that the approach needs more work, and we expect to continue working with Ofgem to develop a reasonable target setting approach ahead of the Final Determinations.

277. We accept a penalty only incentive based only on relevant market segments not yet deemed competitive may have better properties for continuing the drive to a fully competitive market. We seek Ofgem's assurance that such a drive will continue and would welcome the opportunity for a further competition review later in the period.

278. Assuming the drive to competitive segments continues, we believe that the overall size of the penalty might be better related to the total size and value of the relevant market segments not yet deemed competitive rather than basing it on a percentage of RORE. There are two reasons for this.

    a. Firstly, to promote the earliest largest competitive market, encouraging DNOs to drive the largest segments to competition is desirable.

    b. Secondly, where relevant market segments in certain geographies are uneconomically small for competitive providers, DNOs should not be unfairly penalised. For DNOs with very few relevant market segments exposed to this incentive, it is entirely possible that the penalty for poor performance is greater than the total value of the market segment being assessed. Basing the penalty on the value of the market segments exposed to the incentive seems more reasonable.

    c. Furthermore, we note that the two market segments we have moved to competitive operation represent around 60% of the relevant market segments based on number of connections. To discount our penalty by only 22% on the back of this appears disproportionate. Again, this should be made relative to the size of the relevant market segments.

279. We also note Ofgem's concerns in paragraphs 5.158-5.160 in the core methodology document. The changes set out above (i.e. revisiting the competition test and setting the penalty based on the relevant market segment value), will progressively increase competition in all market segments, reducing the segments exposed to the incentive mechanism and thereby allowing the mechanism to progressively narrow its focus on to the market segments that need it the most.

280. If an appeals mechanism is required then the burden of proof cannot sit solely with the DNO. Customers must be able to demonstrate underperformance before Ofgem can take such claims into account.

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

281. Yes. Ofgem's proposal to require reputational reporting of timeliness metrics for all RMS is reasonable.

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

282. Given the context of the Access and Forward-looking Charges Significant Code Review and the changes in connection types and volumes that might occur as the energy system transitions, this is reasonable.

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

283. DNOs are already working to speed up connections, as clearly demonstrated by the ED2 business plan submissions. Therefore no further regulatory mechanisms, such as incentives, uncertainty mechanisms or obligations, need to be developed over and above the existing proposals.

284. Further support for innovation on continuing the development and exploration of automated design and quotation has potential to improve connections quotation speed. Ofgem should be mindful of this in its approach to reviewing network innovation funding bids.

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

285. We have conducted a number of pieces of customer engagement to inform our ED2 plans. These took very different approaches to understanding how customers value their electricity supply, what they value about it and how much they would pay to improve it. We have a considerable pool of customer feedback from which we can draw conclusions, the majority of stakeholders, over 65 per cent in all stakeholder groups, wanted to see at least a "major upgrade" to our network reliability.

286. There has been extensive testing of reliability propositions in our stakeholder engagement programme to date which, non-typically, included costed levels of ambition, providing multiple sources of feedback of stakeholders' willingness to pay (WTP) out with the overall WTP research.

287. Within Wave 2 of our enhanced engagement process[3] we tested our emerging thinking (ET) with the costs of initiatives required to deliver the different levels of ambition. The result of the

[3] Enhanced_engagement_process.pdf (northernpowergrid.com)

engagement on our ET against five propositions, which were tested as part of our work with different groups of stakeholders is shown in figure 1. This set out the investment required as well as the performance that customers could expect from the different options – this included the bill increase that would be required to deliver the change.

288. 810 stakeholders were surveyed on reliability as part of testing our proposals, including 635 domestic customers and 97 SMEs.

289. As part of this, customers were told how this would impact power cuts with a mid-scenario defined as 'Major Upgrade' with the following criteria: a reduction of 20% in the number and 14% in the length of power cuts as well as broadly how this would be achieved.

290. In the case of this option (defined as Option C) included the following initiatives:

a. Accelerated roll-out of existing and new technology on the LV and HV network.

b. Harness smart meter data for fault management and to develop asset replacement programmes.

c. Broader programme to improve service for the most frequently impacted customers.

291. The results of the survey showed that the majority of customers in each group surveyed voted for at least level C (major upgrade) at an increase of between 6% and 27% in cost, and a bill increase of £0.20 to £1.23.

Stakeholder Group	Option A - Current package for less	Option B - Enhanced		Option C - Major upgrade		Option D - Breaking new ground		Option E - A new world	
Domestic Customers	9%	21%		21%		20%		22%	
Rural Customers	-	22%		22%		22%		33%	
SMEs	4%	28%		29%		13%		25%	
Other	7%	22%		21%		26%		24%	
Customer Interruptions	46	41	11%	37	20%	34	26%	30	35%
Customer Minutes Lost	35	31	11%	30	14%	27	23%	23	34%
>12hr Faults	3600	2700	25%	1800	50%	900	75%	0	100%
Multiple Interruptions	16	10%		20%		35%		50%	
Total Cost	£112.7m	£115.2m	2%	£119.8m	6%	£129.3m	15%	£142.7m	27%
Bill Increase	- £0.12	£0.00		+ £0.20		+ £0.63		+ £1.23	

Figure 1. Emerging Thinking feedback

292. Reliability as a whole also received strong feedback from stakeholders in the quantitative prioritisation research conducted as part of the wave 1 engagement, which surveyed 549 domestic and 165 SME customers.

293. As the different levels of ambition had been costed, the feedback from engagement on our ET was further supplemented by the broader WTP with these findings shown in figure 2. Domestic customers were willing to increase bills by £1.24 for improvements at level E of our ET propositions and by £0.63 for a moderate level of improvement.

294. During the WTP analysis, a quantitative prioritisation was developed from engagement piece E021[4]. Figure 3 shows the outputs from this piece, demonstrating that overall, reliability is the key priority area for all consumer groups.

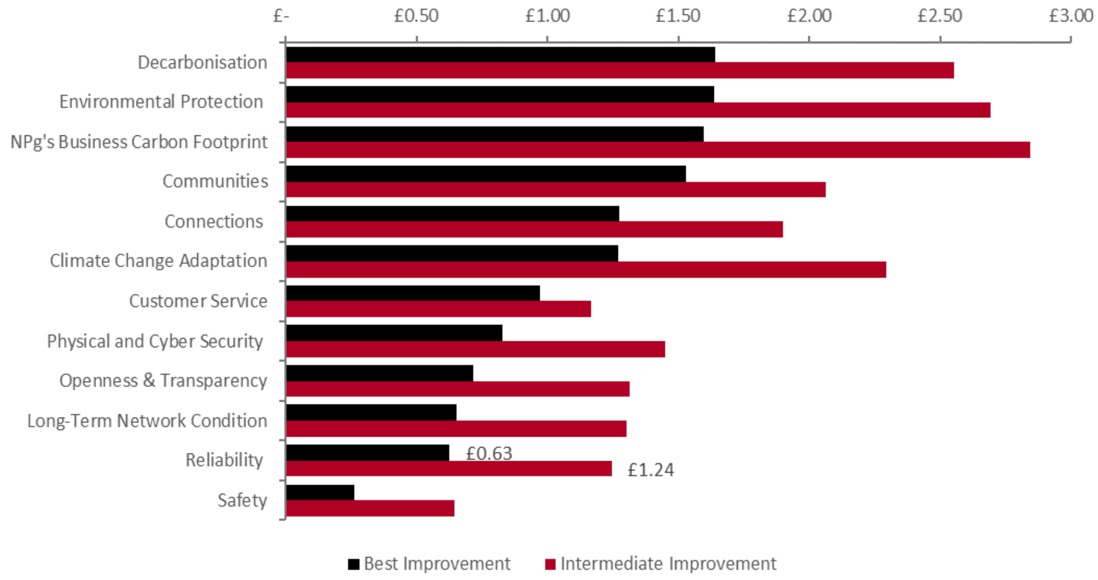

Figure 2. Willingness to pay results (domestic customers)

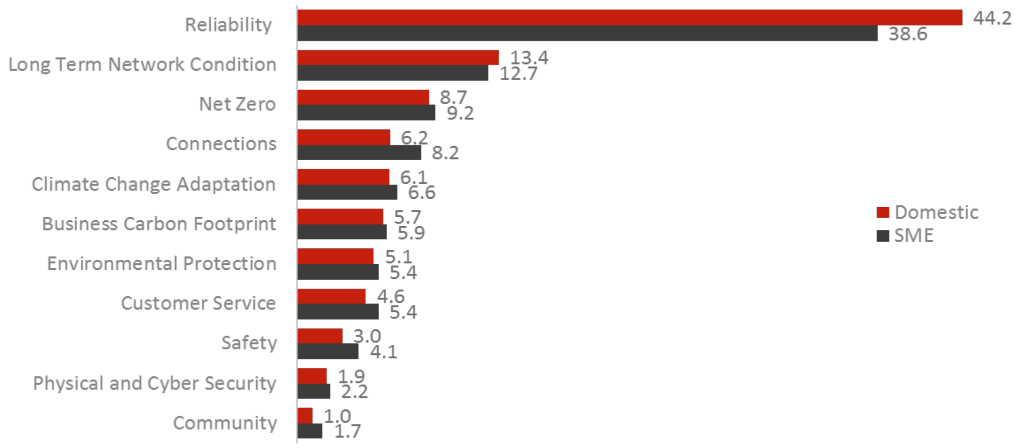

Figure 3. Customer priorities – willingness to pay – quantitative prioritisation

295. A further piece of research work carried out in conjunction with Explain was to explore measurement of inconvenience experienced by customers during a power cut, as well as looking into how much they would value and be willing to pay towards certain service improvements in the area of network reliability.

296. This work was carried out by engaging customers on a personal basis and grouping them according to their experience of supply interruptions to understand how this may affect bias and sensitivity to supply interruptions. The groups covered the broad spectrum from customers having experience of a power cut of 12 hours or more in the last year, multiple long or short

[4] Detailed_engagement_summary.pdf (northernpowergrid.com)

interruptions to those with no experience of a power cut within the last two years (control group).

297. This was aimed at asking customers to think in detail about the impacts of supply interruptions on them personally and on other families in different circumstances, to allow us to understand what customers really value about electricity and what matters most to them when suffering a power cut.

298. Groups of respondents were asked if they were to suffer an interruption to supply, how would they value a reduction in a fault duration typically lasting 1.5 to 3 hours down to 3 minutes? The majority of respondents valued this improvement highly, as the reduction in length was considered significant and more likely to have a positive impact on customers affected. On average, respondents valued this service improvement at 7.72 out of 10 and were willing to pay £5.02 more on their electricity bills per year for this service improvement as per figure 4. Note this value is far in excess of the bill impact of our ED2 reliability proposals.

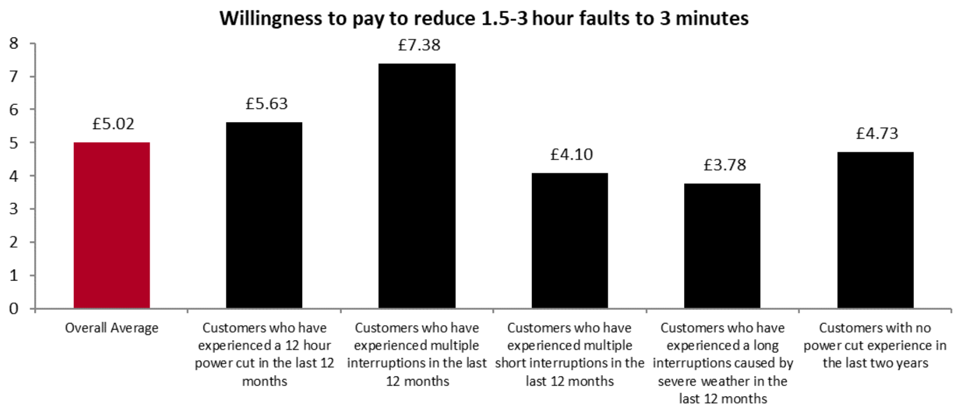

Figure 4. Willingness to pay results (Explain focus groups)

299. In general, customers who had not experienced a supply interruption, were keen on larger improvements in performance although were less willing to pay for it than customers who had recent experience of a supply interruption.

300. The engagement was also carried out during the pandemic, which was a unique opportunity for customers under lock down to better understand & evaluate the impacts of supply interruptions on them when reliance on electricity was heightened.

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

301. Lowering the cap naturally leads to a reduction in the amount of efficient investment that can be made in the network.

302. Assuming that all proposed schemes deliver a similar network performance improvement on a benefit per £ invested basis, then a reduction in the cap will result in a reduction to the number of schemes carried out and hence limit the level of performance improvement that can be delivered in ED2.

303. This will continue to drive the disparity or gap in network performance within the industry between the leading and lagging DNOs. Primarily, those DNOs who were first movers and made network improvements in DPCR5 (when there were no caps in place) will continue to lead, whilst lagging DNOs will no longer have the level of funding required to close the gap. This disparity will subsequently roll forward into benchmarking for ED3 and beyond.

304. On an individual reliability improvement scheme basis, the cap has no impact on a scheme being achieved. It is the lowering of the incentive rate that will impact the number of schemes being achieved simply because a smaller number of schemes will be justifiable on a cost basis.

305. Reducing the cap will only impact the speed (i.e. the number of future price controls) needed for all DNOs, including those currently lagging the industry, to reach the best levels of cost justifiable performance for each individual network.

306. Our ED2 business plan submission and associated EJPs lay out the improvements in network performance that we intended to make and the costs of those improvements. Correlation of this data enables back calculation of an incentive rate which indicates that an incentive rate of the order of 220% higher than that for ED1 will be required to make ED2 HV automation schemes viable. Ofgem has reduced the incentive rate in real terms (including the effects of TIM) by 36pp for CI and 22pp for CML. However, by contrast for guaranteed standard payments related to loss of supply, Ofgem has updated the payment amounts to account for inflation at the start of the price control. This represents an increase of 20.2pp. Clearly this disparity requires further review because essentially the customer inconvenience and disruption is not being valued consistently.

307. Furthermore, HV automation continues to be rolled out across our network on a worst performing circuit basis and this now covers 65% of our customer base. This of course means that 35% of our customers are currently not protected by HV automation and do not enjoy the benefits of it should an interruption occur. The slowdown in investment described above will lead to this inequality across our customer base becoming protracted as timescales for reaching 100% coverage of customer based pushed out further into the future.

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

308. In principle we have no objection to asymmetrical caps and collars as long as the upside and downside risks are properly considered across the ED2 settlement.

309. The revenue cap was put in place for RIIO-ED1 to protect customers from paying for network performance improvement that they didn't necessarily want. Northern Powergrid made a conscious decision in ED1 to limit further investment beyond the financial cap. This is because further investment beyond the cap would not be funded by the IIS scheme.

310. In terms of collars, we agree that DNOs should be encouraged to maintain current performance levels and prevent deterioration. DNOs already have a significant reputational business driver to ensure that this is this case. We therefore think that, in practice, collars could only become active if a DNO became subject to a significant network event or events that were not within their control and out with exclusions of the IIS scheme. The changes to the OOE definition in

conjunction with the expected increased frequency of environmental events as a result of climate change, represent increased risk that should be acknowledged by Ofgem in the setting of the collar.

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

311. The introduction of the Revenue Adjustment Mechanisms (RAMs) gives customers a further level of protection and limits DNOs earning further returns from the suite of incentives. With the primary threshold set at 300 basis points of RORE, we believe that Ofgem should consider that this gives adequate protection to customers and that a further reduction of the IIS incentive cap is no longer necessary.

312. Network performance improvements are finite and in future will be reduced given the performance improvements made to date and as such the scope for future rewards is reduced.

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

313. We support Ofgem's change in approach as it represents a more holistic approach to target setting, in that the cost of making network performance improvements was not taken into account in previous price controls. The cost of making improvements is company specific, depending upon both historical network topology coupled with the penetration levels of automation equipment installed and funded by previous price controls.

314. This will ensure that network performance improvements gained over ED1 will be maintained as a minimum standard of performance.

315. It will also ensure that DNOs who had set themselves more stretching goals to meet customer commitments in their ED2 plans, will do so only when cost beneficial to do so.

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

316. We do not feel strongly how QoS is funded, whether by upfront allowances or incentivised via the IIS incentive mechanism, as long as adequate funding is made available to meet the level of performance desired by our customers at a cost they are willing to pay.

317. If ex ante QoS funding is not made available, then we believe the IIS scheme is a package of components that need to work together to allow the same outcome. The package of components includes Ofgem ED2 targets, incentive rates, revenue caps and TIM.

318. The current incentive rate reduction proposed for ED2 needs to be sufficient to fund investment to close the gap between present levels of performance and the targets.

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

319. Sustained weather events that cause widespread fault disruption to the network but that are not focused in a 24 period, as per the definition for a severe weather event, are genuinely "exceptional" events. The heat wave experienced this summer was an example of such a sustained event that has given rise to a broad range of incidents and a significant number of customers off supply. During ED1, these types of events would qualify as an OEE occurrence, but under Ofgem's proposals for ED2 they would not. Ofgem should revised its definition to consider climate change driven sustained environmental events.

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

320. We agree with Ofgem's assessment.

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

321. We are supportive of Ofgem's revised approach to funding of WSC and the ability to identify additional schemes during the period that will benefit customers.

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

322. We are working with Ofgem and other DNOs through the Safety, Resilience and Reliability working group (SRRWG) to develop the framework. We support the drive for transparency on the Worst Served Customer (WSC) investment position and we have fed into the governance document to ensure the mechanisms are efficient and fair.

323. We believe a suitably modified version of the Engineering Justification Paper on WSC, combined with our updated ED2 WSC Code of Practice, will allow us to communicate the basis of investment to our wider stakeholders and simplify the subsequent annual reporting that will form part of the governance requirements.

324. We have supported development of the governance document with a view to ensure that the document also complements the relevant licence conditions.

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

325. No. We have fundamental concerns with the proposed approach for network risk outputs. We believe that holding targets static with no consideration to the impact of cost disallowance is flawed. Ofgem must either increase allowances or reduce the NARMs targets.

326. The proposed NARMs outputs contained within our plan are based on the mix of work and volumes of interventions we have submitted. Funding within the DD does not allow for delivery of our planned volumes and therefore it is unreasonable to expect that same amount of NARMs output to be delivered for a much lower amount of investment.

327. Our analysis based on the proposed funding within the DD shows that under this proposal we would need to outperform by 32% and 41% of additional long term monetised risk outputs for the Northeast and Yorkshire respectively. This is level of expected outperformance is unjustifiable and is far in excess of outperformance achieved historically where physical work is required on the assets.

328. It is not clear whether there has been any consideration to the scale of challenge each DNOs proposed targets represent and therefore the degrees of freedom that may be available to each DNO to further optimise their intervention strategy in order to achieve or outperform their targets.

329. To derive the baseline network risk output, it is stated in the methodology that consideration was given to reflecting proposed volume disallowances, however this was dismissed as:

   a. in ED1 all DNOs are on track to “deliver their risk point output, with several DNOs deploying a materially higher proportion of refurbishment interventions to replacement activities relative to their forecast"; and

   b. the NARM framework in ED2 will “continue to give DNOs sufficient flexibility to innovate, manage their assets appropriately and deliver their outputs”.

330. We challenge these assumptions as not all DNOs will materially out-perform ED1 targets. We have optimised our ED1 plan to allow us to trade between asset groups to deliver 100% of our targets whilst investing 100% of our allowances. This optimisation has been necessary for us to manage and fund additional cost pressures during the period ED1, such as flood defences for climate resilience and cyber resilience. We do not plan to out-perform targets or cost allowances; we will deliver 100% of targets for 100% of totex but this has required the flexibility to make trade-offs.

331. The disproportionate benefit delivered by refurbishment in ED1 has been designed out of the ED2 framework through the implementation of NARMs (which replaces NOMs) and long term/whole life risk through the publication of CNAIM v2.1. Ofgem’s proposed approach on NARMs ignores the fact this change occurred in the methodology to mitigate concerns that Ofgem previously raised.

332. The ability to “out-perform” through refurbishment is also subject to refurbishment being a technically viable solution for a given asset category and the ability to “out-perform” through asset trading (within or across asset categories) is dependent on there being assets to trade that require replacement. DNOs do have the freedom to use these two abilities across all their asset management activities whilst meeting their obligations.

333. On the review of IGP arrangements, we agree with the proposed approach to retain requirements on network companies to produce an IGP which sets out how they will gather and record the information required to implement the CNAIM.

334. Regarding the consideration of an uncertainty mechanism to manage non-NARM related expenditure, we agree with the proposed approach not to introduce an uncertainty mechanism for non-NARM related expenditure.

335. And finally on incentive arrangements, we agree with the proposed approach to set the deadband around the NARM output at +/-5% and to retain the RIIO-ED1 penalty rate at 2.5% of avoided costs associated with unjustified under-delivery against the NARM output.

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

336. We agree with the approach given the difficulty in forecasting the costs and volumes of such events. The provision of funding after the event removes the subjective element of forecasting these uncertain costs.

337. We disagree with the statement that a re-opener style approach could have an impact on the level of response that we provide during an exceptional event. Cost recovery is not an immediate factor in determining the level of service we give to our customers in an event.

338. The Ofgem consultation position is not clear on the mechanism for assessing cost efficiency after the event.

339. These types of events, by their nature, are exceptional and the costs to deal with the event will also be higher than those typically incurred during more normal severe weather events. Additionally, during the same weather event DNOs will be impacted differently – we experienced this first hand with Storm Arwen with the Northeast being more severely impacted compared to the Yorkshire region. Comparative analysis of relative cost efficiency will therefore need to cater to those discrepancies.

340. We disagree that allowable activities should be pre-defined ahead of an event occurring due to the uncertainties involved with events of this type.

   a. The cause and type of the event is unknown as is the extent of the potential damage.

   b. Therefore, the activities to restore and repair the network are equally as unknown.

   c. This makes it difficult to pre-define the activities in any meaningful way, other than a relatively high-level approach which would reduce the funding mechanism's effectiveness.

341. We believe a more appropriate approach should be that following an eligible event DNOs should submit all relevant costs and justify each activity on an individual basis. All costs incurred by the DNO should be included in any assessment for pass-through.

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

342. We agree there should be no cap. The scale of such events are outside of our control and Ofgem should assess the costs individually after the fact.

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

343. Yes, we agree with the proposed approach to the physical site security re-opener.

344. We agree with the proposal not to use the standard materiality threshold. This would be illogical as that threshold could easily rule out entire distribution programmes of site security enhancement. Where the government considers enhancements to site security important enough for national security, Ofgem should be willing to fund it. If it does not, it is failing to meet its duty to allow companies to finance the cost of requirements imposed upon them.

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

345. Yes, we agree with the proposed approach to the ESR re-opener.

346. While we have not submitted costs in this area for ED2 we welcome the proposal for a re-opener mechanism in the event that costs arise during the control period.

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

347. We agree with the proposed approach to fund DNO telecoms resilience activities through baseline allowances.

348. Within our business plan we set out our telecoms strategy to improve the resilience our operational telecoms network. We received baseline allowances in ED1 to commence this significant programme of work to enable smart grid development and we will continue to develop it further in ED2 through appropriately funded baseline allowances. We will continue to work with other DNOs and Ofcom on the future availability of radio spectrum, building the outcomes of this into our telecoms strategy for ED3 and beyond.

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

349. Yes. We agree that the cyber resilience IT and OT plans should be assessed against both Ofgem's Business Plan Guidance and the RIIO-2 re-opener guidance.

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

350. Yes. We agree with the application windows for all DNOs to be available in Year 1 (2023/24), and Year 3 (2025/26) of the price control period.

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

351. No, we do not agree with Ofgem's proposal to provide cyber resilience OT allowances under the use it or lose it (UIOLI) mechanism as it has been formulated. Not only is the additional mechanism unnecessary, considering the application of PCDs and two re-opener windows, but there are fundamental flaws in the design. The UIOLI mechanism should simplified.

352. Ofgem has included outcomes based PCDs for cyber resilience OT to ensure DNOs are held to account for non-delivery of measures they have identified in their plans. There is a Licence Condition to report progress, on a bi-annual basis, against delivery of PCDs that are set. This is

in addition to the NIS reporting and the requirement for all evaluative PCDs to be reported against the year after the delivery date. On top of this, there are two re-opener windows to allow DNOs an opportunity to update their cyber resilience OT plans to account for the less certain nature of these costs. It is completely unnecessary to layer on top another mechanism which is looking to remedy the same risks that Ofgem has already resolved.

353. There are fundamental flaws in the design of the mechanism. Normally, a UIOLI allowance will ring-fence funding for a specific output and the allowance are only provided to the extent they are spent on that output. However, the current drafting (para 6.224) reads as though Ofgem would undertake a retrospective assessment of costs spent with a risk that the allowances would be clawed-back if Ofgem considered them to be inefficient. This approach would demonstrate severe micro-management by Ofgem, cause concern due to the subjective nature of the assessment (such as engagement with Ofgem and stakeholder support for the plan) and would reduce the likelihood that DNOs will invest. This would not be in the interests of consumers.

354. From bilateral conversations with Ofgem we understand that the policy intention is that the mechanism will be implemented with an asymmetrical approach, and that there would be no ex post assessment of how an allowance has been spent (above and beyond the reporting protocols described above). In this case, for any overspend TIM applies (and the costs are shared equally between the DNO and customers) and for any underspend TIM does not apply (and the allowance will be reduced, passing on the full saving to customers). We agree with this approach.

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

355. We believe that totex benchmarking and provision of ex ante allowances provides companies with the strongest incentives on total cost efficiency.

356. We also disagree with the exclusion of rising and lateral mains costs. Ofgem has excluded rising and lateral mains costs from totex assessment. Simultaneously, it has included rising and lateral mains in the main cost benchmarking MEAV, with a high weighting at the underground service unit cost. This creates an inconsistency between cost drivers and costs.

357. At least one aspect of Ofgem's pre-modelling normalisation approach causes a potential inconsistency in the treatment of DNOs.

   a. SP Manweb has been granted a company specific adjustment as SPEN claimed that the interconnected, or meshed, configuration of their Manweb network results in additional operation, maintenance and modernisation costs, totalling £23.4m annually in RIIO-ED2. This factor leads to a higher MEAV cost driver. In ED1 a MEAV reduction was processed in relation to SP Manweb's company specific adjustment; this has not been processed in ED2 and further, Ofgem has modified its MEAV variable at ED2 to include pilot wires which creates a significant additional uplift to SP Manweb's MEAV relative to other DNOs.

Ofgem's treatment of MEAV in this instance appears to double count SP Manweb's company specific adjustment.

b. To address this inconsistency, Ofgem should implement a MEAV reduction for SP Manweb, as it did at ED1. The reduction will need to be significantly larger than at ED1, due to the inclusion of pilot wires in MEAV.

c. If Ofgem does not intend to adjust MEAV to match its company specific adjustment for SP Manweb, in order to ensure fair treatment for all DNOs, Ofgem needs to allow a further submission of evidence based on unique features of other networks as clearly set out in our final business plan (Annex 6.3 Cost Benchmarking – page 17). As we highlighted in our business plan, our networks also face additional costs due to unique historical network configurations. We did not submit a request for an adjustment on the assumption that Ofgem's use of MEAV would render it un-warranted.

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

358. We do not agree with Ofgem's approach to totex benchmarking in its current form.

359. As a matter of principle, we strongly favour totex benchmarking over disaggregated benchmarking due to its ability to measure overall value for money, capture trade-offs across cost categories, and deliver strong incentives for DNOs to pursue synergies and achieve efficiency improvements.

360. Ofgem's current totex benchmarking approach suffers from a raft of errors, including data errors and inconsistencies, flawed cost drivers (endogeneity), model specification issues, and double counting. As a result, Ofgem's totex modelling results are not fit for purpose.

361. Important changes are needed.

a. Ofgem should not rely on totex model 1 at all or totex model 2 as it stands, since both fail to control appropriately for differences in planning scenarios between companies. There are also multiple further problems with the capacity released variable that Ofgem uses in these models, which we set out below. totex 3, in contrast, suffers from none of these problems.

b. Ofgem should abandon totex model 1 as it is not fit for purpose. Ofgem should only use totex 2 if material changes are made to the definition of the capacity released variable to resolve its existing problems. If these changes are not or cannot be made, totex model 2 should also be dropped.

c. We have also identified further problems with the data used in Ofgem's totex benchmarking. It is clear that considerable further work is needed to fix errors and validate this data, to ensure all companies are benchmarked on an equal footing. A coordinated process is needed over the course of the autumn to carry this out.

Plans are not comparable, creating a material challenge for benchmarking

362. The majority of the issues in the totex modelling process are driven by inconsistency in the critical inputs to the process: the business plan data. This was a critical error in Ofgem's process ahead of and during the business planning period.

a. Ofgem did not provide companies with a common decarbonisation planning scenario on which to base ED2 business plans, despite repeated requests for this during Cost Assessment Working Groups and bilateral meetings.

b. Instead Ofgem's Business Plan Guidance stated that DNOs should use all three net zero-compliant FES scenarios, and all five CCC scenarios from the 6th carbon budget, to determine the range of demand for their networks, leaving open eight possible scenarios.

c. Ofgem then stated that it expected DNOs to develop further scenarios based on these: "Each DNO will have to translate these national pathways into scenarios that are applicable for its licence area." [5]

d. As a result, companies have based their plans on a wide range of very different decarbonisation scenarios.

e. These plans are not therefore directly comparable to one another, as they contain programmes of work designed to facilitate very different low carbon futures.

Controlling for planning scenario is therefore critical, but Ofgem's models fail to do so

363. When Ofgem benchmarks the costs set out in company business plans, it is therefore critical that it effectively controls for differences in planning scenarios. If this is not done, the benchmarking results will inevitably capture differences not only in managerial performance – which is what Ofgem is trying to capture – but also differences in DNO planning assumptions. Both will then end up being interpreted as differences in efficiency. All other things being equal, a DNO that has assumed lower LCT uptake during ED2 will appear more efficient than one that has assumed higher uptake.

364. Despite this being a critical modelling issue, Ofgem has however only appropriately controlled for differences in planning scenarios in one of its three totex models. Only totex 3 includes an explanatory variable that directly measures the different scenario assumptions made in DNO plans: a composite variable of LCT uptake. totex 1 and totex 2 on the other hand rely on other cost drivers as 'proxy variables'[6] for the impact of different plan scenarios.

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[5] Ofgem (September 2021) RIIO-ED2 Business Plan Guidance, paragraph 5.7

[6] In regression analysis, proxy variables can be used when the true variable of interest is difficult or impossible to measure. They should be closely correlated with the true variable of interest.

a. Totex 1 uses a single cost driver[7]: a CSV made up of MEAV, customer numbers, total faults, peak demand, capacity released, overhead line length, network length, span cuts and ONI faults.

   i) Of these nine variables, only capacity released, and possibly peak demand, are likely to provide some control for different plan scenarios.

   ii) However, neither will be effective in capturing differences in planning scenarios. Capacity released will also capture other factors, such as DNO investment cycles and wider network management strategies that are not necessarily correlated with plan scenarios. Peak demand will also reflect wider trends in electricity usage and will therefore be confounded by background noise.

   iii) In fact, the correlation coefficient between Ofgem's capacity released variable and Ofgem's LCT uptake variable is only 0.37, indicating hardly any meaningful correlation (see figure 5). This may increase to around 0.47 after addressing a data inconsistency error that is discussed below (see figure 6). However, this finding casts significant doubt on the extent to which capacity released provides an effective proxy for plan scenarios.

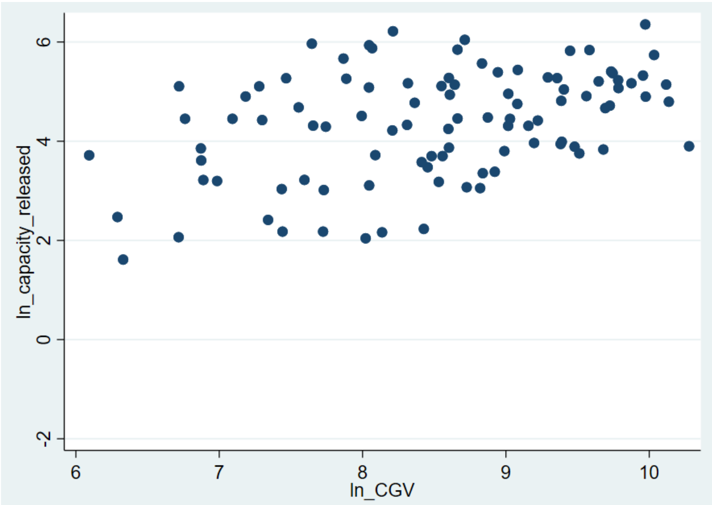

Figure 5. Scatter plot of Ofgem's capacity released variable against Ofgem's composite LCT uptake variable

[7] Other than time trends.

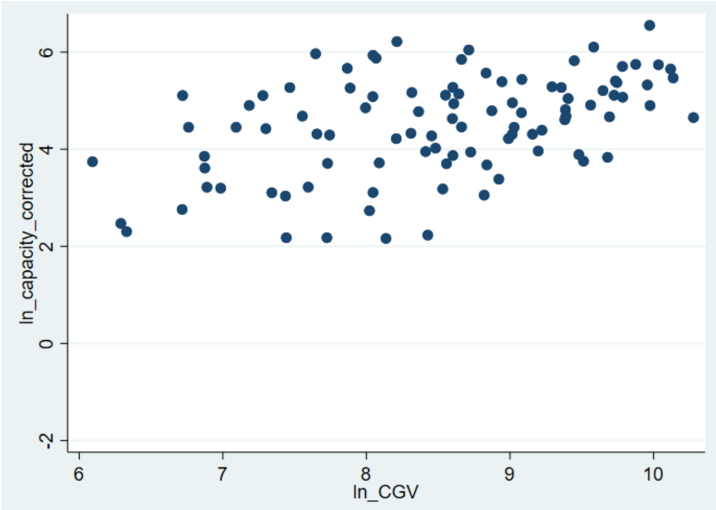

Figure 6. Scatter plot of corrected capacity released variable against Ofgem's composite LCT uptake variable

b. Furthermore, within totex 1, capacity released and peak demand are not included as additional cost drivers in the model, but only within a CSV. This will further limit their ability to control for differences in plan scenarios.

i) This is because the variables are combined with a number of other variables, using fixed weights, to create a single CSV.

ii) This means that the underlying variables cannot act independently to explain variations in cost. The impact of these variables will therefore only be second order, via the small impact their variation will have on the overall CSV value[8].

365. Totex 2 uses two cost drivers[9]: a CSV made up of MEAV, customer numbers, total faults and peak demand, and separately capacity released, averaged across each price control period. Peak demand suffers precisely the same issues as described above in (a) and (b). Capacity released suffers the same issues described in (a). However, its inclusion as a separate variable allows it to provide more control than it does within a CSV, and as a result makes totex 2 slightly less flawed than totex 1.

366. Additionally, Ofgem should reduce the components of the 'top-down' CSV down to MEAV and customer numbers. A CSV made up of four drivers is not a top-down CSV; it is a bottom-up CSV.

i) Fault volumes should be dropped as it rewards DNOs who forecast an increase in volumes. Most DNOs have forecast flat fault volumes, so this driver is meaningless and does not explain changes in totex.

[8] This topic was explored in a paper commissioned by Ofgem from an academic at RIIO-GD2 (Professor Andrew Smith (2020) Note for Ofgem on the computation of CSV weights), which explained that using a CSV forces the ratio of coefficients on the individual variables to be fixed, equal to their relative weights within the CSV. This is "overly restrictive" because the relative elasticities should be based on the relative marginal costs of the variables, not their relative weights.

[9] Other than time trends.

ii) Peak demand should be dropped as its forecasts are historically inaccurate across all DNOs, and it is subject to human error in its measurement. It cannot be trusted to set allowances.

There are critical regulatory and technical statistical problems with using capacity released

367. The problems with totex 1 and totex 2 do not end there.

368. The capacity released variable relied on in totex 1 and totex 2 is endogenous, i.e. it is a variable that is within company control (an intermediate output of the firm) and will be determined or influenced by other variables included within totex 1 and totex 2.

369. This leads to two immediate problems.

   a. As we have often argued in the past, use of cost drivers that are within DNO control is highly problematic because if there is a credible belief that a similar model may be used again, it incentivises DNOs to favour business solutions that 'create' more of the relevant output driver (in this case, more investments that release capacity), even where this is not efficient. This is because, at the margin, any company that is able to increase the value of cost drivers will make the DNO appear more efficient in the benchmarking and deliver more funding. This is highly likely to lead DNOs to favour solutions that are not cost minimising.

   b. Including an endogenous variable in a regression will likely lead to biased parameter estimates and a mis specified model, i.e. the results of totex 1 and totex 2 are not robust.

370. Ofgem acknowledges the issue of endogeneity: "We acknowledge that [capacity released] is endogenous and under DNOs' control."[10]

371. However, Ofgem argues that the use of an endogenous variable is justified because "the sole use of exogenous drivers to account for load growth and LCT uptake may not reflect the reinforcement requirements that LCT growth places on individual DNOs depending on the degree of utilisation of the existing network (alongside other factors)."[11]

372. This provides no reasonable justification for including a variable with so many practical and technical problems.

There are a large number of data errors and inconsistencies that need to be fixed and investigated

373. Notwithstanding our criticisms above regarding Ofgem's method, we have found a range of data issues that need to be addressed. Below we set out the issues we have identified so far.

   a. There is a clear inconsistency error in the capacity released data.

[10] Ofgem (June 2022) RIIO-ED2 Draft Determinations – Core Methodology Document, paragraph 7.110

[11] Ofgem (June 2022) RIIO-ED2 Draft Determinations – Core Methodology Document, paragraph 7.110

b. Capacity released captures only one aspect of the scale of work needed to make networks ready for LCT uptake, i.e. increases in transformer capacity. It entirely ignores upgrades needed to circuits.

c. The capacity released data is extremely noisy and, given other problems with using this cost driver, it is not clear that it can be used to support any kind of robust analysis.

d. There seem to be oddities and clear inconsistencies in the MEAV data that require further investigation.

374. We provide more detail on these issues in the sections below. There may well be further issues with the input data that we have not yet identified, in particular the forecast data provided by companies where we have a concern that data has not been prepared on a comparable basis. Beyond the response deadline, considerably more work is needed to validate the data that goes into Ofgem's models to ensure it is robust.

Inconsistency error in capacity released

375. If Ofgem intends to rely on capacity released to support its FD benchmarking, then it must fix the data issues within capacity released, given the critical role of this variable in totex 1 and totex 2. These issues also affect certain disaggregated models (e.g secondary reinforcement), which also use capacity released.

376. The first problem with capacity released is a basic data error, as Ofgem has failed to secure data on a consistent basis across DNOs. Some DNOs are currently being benchmarked using gross capacity released (i.e. the total capacity of a new asset replacing an old asset), while we are benchmarked using net capacity released (i.e. the incremental capacity added when an asset is replaced), and SSEN the disposal volumes of capacity released. This amounts to a significant error which limits the reliability of Ofgem's entire cost benchmarking exercise. We estimate the impact of this error (quantified using gross capacity released for all DNOs) to be highly material.

377. Our understanding of the data submitted by companies is as follows.

a. We have submitted capacity released on a net basis.

b. SSE has submitted capacity released data using disposal volumes.

c. In contrast, ENWL, WPD, UKPN and SP appear to have submitted capacity released on a gross basis.

378. Ofgem appears to have undertaken its benchmarking using data that is simply not comparable across DNOs. As it stands the results of any Ofgem model that relies on the capacity released variable are wrong and should not be relied upon to set allowances.

379. If Ofgem intends to continue to rely on capacity released in its benchmarking then it must ensure that consistent data is used across all DNOs in all relevant models. It should first clarify

whether it intends to use capacity released on a gross or net basis[12] and provide reasoning for its choice. It should then obtain comparable data on this basis. Ofgem should align the measure of capacity added across the totex and disaggregated modelling suite to ensure consistency. We recommend the use of gross capacity released as it ensures that the cost per MVA is correct.

Partial coverage of capacity released

380. In addition to the consistency issue above, Ofgem's capacity released variable is only a partial reflection of the reinforcement activities carried out by DNOs. It only includes capacity released through transformers, and ignores upgrades to circuits, which is an equally important driver of costs. It therefore fails to capture the concept it is supposed to measure, i.e. the scale of work necessary to upgrade networks in order to accommodate LCT uptake.

381. Omitting capacity released through circuits means that Ofgem's models are biased towards companies whose reinforcement activities are directed more towards transformers.

382. The value to customers from circuits being replaced or added is not derived from the km length that is installed but rather from the amount of new capacity that is created. Making an assessment on a generic basis of the capacity released from this work type provides a comparable output basis for the work done on transformers or circuits.

383. Ofgem should include capacity released through circuits reinforcement in its capacity released cost driver. Data on circuits capacity released is not currently provided through the BPDTs, so it is crucial that Ofgem engages with DNOs immediately to develop and collect the necessary data.

Noise in capacity released

384. It is also worth inspecting the capacity released data (see figure 7 below). The data is extremely noisy, limiting its ability to provide any kind of robust analysis.

[12] it is unclear from the Draft Determination documentation whether Ofgem intended to use net or gross capacity released. For example, footnote 198 of Ofgem's Core Methodology Document states *"Capacity released is a measure of the additional capacity available as a result of reinforcement activities where one asset is replaced with an asset of greater capacity, eg if a DNO replaces a 50kVA transformer with a 200kVA transformer then the capacity released is 150kVA".* This suggests the Ofgem intended to benchmark on a net basis. On the other hand, footnote 211 of the same document states that the cost driver for totex Model 2 is *"the gross capacity released through conventional and innovative reinforcement interventions"*, suggesting Ofgem intended to benchmark against capacity released on a gross basis.

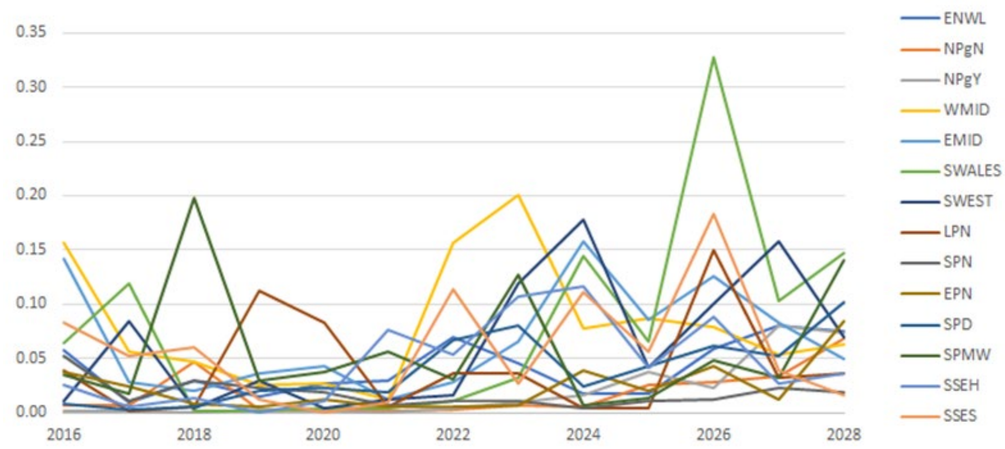

Figure 7. capacity released per thousand customers

385. For the totex 2 model, Ofgem averages this data over the ED1 and ED2 price controls (see figure 8 below) to smooth out this noise. However, given the lumpiness of the underlying data, this leads to potentially arbitrary values driven by the timing of the price controls and where spikes occur in the data. For example, a large spike in SWALES in 2026 drives an increase from 9th highest capacity released in ED1, to 1st highest in ED2. There is also no obvious consistency across the two price controls: capacity released decreases for some DNOs, increases for others, and the ordering of DNOs is significantly different between ED1 and ED2. The idea that capacity released can control effectively for differences in DNO plans is therefore not credible.

386. To address this issue, Ofgem should reduce its reliance on capacity released at least partially, by dropping totex 1, or fully, by dropping totex 1 and only retaining totex 2 if the capacity released variable can be markedly improved.

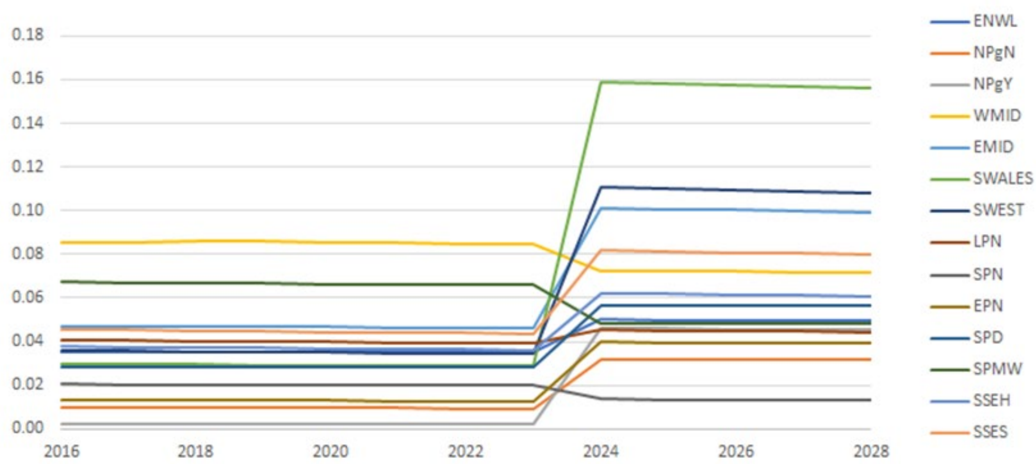

Figure 8. capacity released (price control average) per thousand customers

Issues in MEAV

387. There are also a number of issues in MEAV, another critical cost driver which receives the vast majority of weight within the CSVs of all three totex models.

388. First, there are a number of known issues in the way MEAV has been calculated (these issues also affect a number of disaggregated models which use MEAV as a cost driver):

a. SSE has made a sizeable forecast data cleansing adjustment in 2023/24 that should be scrutinised.

b. There is no reduction made to SPMW's MEAV in relation to its company specific factor adjustment which amounts to £117m (or 7% of submitted totex) over ED2. The related MEAV adjustment should be significantly larger than in ED1, as pilot wires are now included in MEAV (see response to Core Q-63).

c. The inclusion of the RLM category is inconsistent with the treatment of costs as it is removed prior to totex benchmarking (see response to Core Q-63).

389. Second, we have identified that NPg (along with ENWL) has the lowest forecast MEAV growth of the DNOs. MEAV growth rates over ED2 range from 2.9% (NPgN) to 6.6% (SSEH, excluding the impact of the data cleansing adjustment). This does not appear to be consistent with the fact that the planning scenario benchmarked for NPg was higher than most other DNOs. Ofgem should therefore examine the data and engage with DNOs to ensure that the MEAV figures have been prepared on a consistent basis.

390. More generally, we would advise Ofgem to revisit the cost driver data to ensure that none of the cost drivers used are influenced upwards by unjustified high forecasts.

The issues in the totex modelling also lead to a significant risk of double counting with the demand driven adjustment

391. Finally, because totex models 1 and 2 fail to control properly for planning scenario differences, this leads to a critical risk of double-counting with the demand driven adjustment. We discuss this in more detail in our response to Q105

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

392. No, we do not agree with the proposed assessment approach for primary reinforcement. We have a number of concerns and believe that it does not address the bespoke nature of the works associated with primary network intervention schemes targeted at solving specific network capacity constraints. These schemes involve consideration of load growth over time at sites, use of customer flexibility, consideration of synergies such as asset condition and ensuring that if work is required at a site that any new assets are capable of delivering the future capacity needs. Ofgem has not used the EJPs in their assessment for DD and we believe that this approach is flawed.

393. This response sets out the key issues of in the modelling that Ofgem needs to address.

Unit cost adjustment factor

394. The unit cost adjustment factor is based on all substation reinforcement costs (i.e. both flexible and non-flexible solutions), meaning the current approach mixes both short term (i.e. flexibility) and longer term (i.e. smart and/or conventional) solutions. Flexibility will in the majority of cases, only be suitable as a temporary deferral solution, whereas conventional solutions provide a benefit over a far longer timeframe. Combining different solutions results in an overall lower unit cost but does not reflect that flexibility solutions incur an ongoing cost (for the payment of services), whilst smart or conventional solutions are a single one off investment to install the solution.

395. Short term and long-term solutions do not deliver the same benefits, so their costs cannot be compared in this way in the same benchmarking assessment. Ofgem must either assess these solutions separately, or use a comparable measure of costs that cover the same timeframe (e.g. measuring just the annualised costs of long-term solutions).

Cost of capacity (CoC) adjustment factor

396. We disagree with the use of average historical primary network MEAV and total firm capacity as a benchmark for releasing incremental capacity to the network. Primary network interventions are based upon the specific network constraint that needs to be resolved and the underly network topology. Whereas historical MEAV represents the cost to build an entire new network. Therefore, there is limited correlation between the historical cost to build a network and the intervention cost to release incremental capacity.

397. For example, some interventions are able to target small sections of low rated overhead line circuits to achieve relatively large MVA gains. Whilst other interventions could involve complete underground cable circuit replacements to release the same amount of capacity. These choices of solution are impacted by the local network topology and the nature of the constraint, and yet both interventions release the same level of capacity for significantly different costs. Therefore, they cannot be compared like-for-like; the proposed works are driven by the nature of the constraint, the suitability of available solutions and not solely the magnitude of the load increase.

398. Historical MEAV does not necessarily represent how we would build networks now or in the future. For example, we are much less likely to be able to build new EHV overhead lines, due to the challenges in securing consents and wayleaves for overhead routes. This typically results in either a full, or part, underground cable route being required, and therefore a greater cost incurred (when compared with how the network was originally constructed).

399. The end result of this specific benchmark is heavily influenced by the historical network design choices of each DNO made over a number of decades, rather than an assessment of whether or not the incremental capacity is being delivered efficiently for the given constraint they are trying to resolve.

400. Specific EHV scheme interventions cannot be compared in the same benchmarking assessment and individual scheme assessment via EJPs is necessary.

Volume adjustment (see also Core-Q66 response)

401. We have material concerns with the volume adjustment in how it seeks to baseline companies using a ratio of forecast growth above firm capacity by the end of ED2 and network capacity added on completion of the proposed works. We believe that the short-term forecast load growth window favours short-term solutions (i.e. flexibility procurement) and does not fairly assess the benefit of long-term infrastructure investments.

402. Having reviewed Ofgem's proposal we believe that the proposed volume adjustment will penalise DNOs where the demand exceedance occurs in late ED2 or early ED3 (i.e. not immediately), and the demand growth (in the short term) is initially shallow. This could potentially arise under some of the future pathways driven by energy efficiency initiatives before growth driven by EVs and HPs starts to materialise in the mid-2020s. It does not consider the proposed intervention type or driver and the long-term network requirements in that local area.

403. Considering long-term investments against short-term forecast growth projections is not an efficient benchmarking assessment when we need to prevent a lack of network capacity being a barrier to achieving net zero.

404. Ofgem's assessment of primary reinforcement volumes should instead take account of engineering evidence provided on the planned investments.

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

405. No, we do not agree with the proposed application of a volume adjustment.

406. This prioritises short-term solutions in lieu of the long-term network need for increased electrical capacity to enable net zero. When considering long-term investment against short-term forecast growth projection, the volume adjustment is not an effective benchmarking assessment.

407. The short-term forecast load growth window favours short-term solutions (i.e. flexibility procurement) and does not fairly assess the benefit of long-term investments. Where there is certainty in future load growth projections then consideration needs to be given to the most economic solution to deliver that electrical capacity, which could be via the use of enduring flexibility contracts or it could be via the use of larger network assets.

408. Each company has assessed projected demand growth on their networks, identified the constraints resulting from this and the solutions to address these. The solutions are wide-ranging and varied, with no "standard" solution for addressing the constraint; there will be a bespoke solution for each constraint specific to that local network area considering

opportunities for customer flexibility, synergies with other investment drivers, potential smart grid solutions and, lastly, additional network infrastructure. Therefore, assuming a form of overarching industry average is not appropriate.

409. A more robust approach to assessing primary network reinforcement is to assess proposed schemes individually, based on the engineering rationale presented in the EJPs. This would test that the most economically efficient solution has been justified to support the long-term network requirements and not just the projected load demands to the end of 2028.

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

410. The proposed assessment approach contains some material errors that need to be corrected if it is to be used:

a. As set out in Q64, the transformer MVA volumes used in the modelling are inconsistent They include a mix of gross and net capacity added, and disposal volumes of capacity released, because DNOs have interpreted BPDT guidance differently when filling out the main CV2 table. The BPDT guidance does not explicitly request net or gross capacity but uses the statement "The DNO must provide the capacity released by work at the time of energisation (in MVA)". Ofgem should clarify that this data should be corrected to gross capacity released MVA, so that capacity released is on a like-for-like basis across DNOs, and as stated in the core methodology document. Ofgem should also investigate and resolve any other sources of inconsistency, such as use of volumes disposed.

b. Generation LCTs should be removed from the volumes adjustment factor calculations as they do not drive thermal reinforcement being assessed in the modelling. Only the demand side LCTs associated with electric vehicles and heat pumps should be used in the calculation.

c. The circuits volume adjustment factor should be based on circuit MVA capacity released volumes as a ratio of LCT MW installed capacity rather than on km/LCT volumes. This is because the relationship between circuit reinforcement and LCTs is not one of circuit length. The capacity released for HV circuits can be at least 10 times more than for LV circuits. Using only circuit length does not capture this important distinction. Circuit MVA capacity released values could be either requested from the DNOs or calculated using submitted circuit volumes and typical circuit ratings. It is clear from LV/HV mix in the circuit volume submissions that DNOs have differing assumptions about where LCTS will connect.

d. For Looped Services, the unweighted "average of an average" measure being used to calculate the adjustment factor is statistically unstable and disproportionately biased by outliers, a material issue given that not all DNOs have requested ex ante funding in this category. We recommend use of a weighted sector average calculated using only the reinforcement volumes and LCTs of the DNOs that have submitted volumes for this category.

411. The approach adopts an overly simplistic approach to modelling this investment category. The relationship between secondary network demand growth and reinforcement expenditure is complex and consists of many factors - not just LCT growth. DNOs' differing assumptions on customer behaviour in using LCTs, peak loading impacts and network conditions (present network utilisation, asset ratings, network topology) all are important and relevant, which have not been taken into account. Consideration needs to be given to the further use of qualitative adjustments using submitted EJP evidence.

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

412. We disagree with the level of disaggregation used to calculate the unit costs for transformer reinforcement, circuit reinforcement and proactive service reinforcement due to the lack of visibility around the underlying data.

413. We are also concerned that, while we understand that the use of more aggregated average costs have the benefit of simplicity and work well where different DNOs are doing a similar mix of work, they do not work well in cases where either the mix of work is very different (such as underground versus overhead circuits) or where a single DNO has a bespoke asset type of higher cost (such as 20kV equipment).

414. In summary the key aspects that we require to be addressed are:

a. The transformer MVA volumes used are inconsistent because DNOs have filled out the CV2 table differently as explained in our response to question 67.

b. We believe that further assessment should be performed to determine whether the mix of work is similar across DNOs for overhead line/underground cable. The industry median should not be being set by a DNO doing disproportionately more of cheaper overhead line work.

c. We believe that we should have a qualitative adjustment for the work proposed on our Northern Powergrid Northeast 20kV equipment where we are being penalised due to an industry median that is influenced predominately by 11kV equipment.

d. More transparency is required regarding the expert view which is used for proactive service replacement based on the asset replacement expert view. It is appropriate to use an asset replacement cost but for reasons of transparency we require evidence to be provided to us providing further details about the basis of the expert view. We reserve the right to challenge this view if we then disagree with it.

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

415. We do not agree with the proposed assessment approach for fault level reinforcement. The data upon which the benchmarks are being set is fundamentally flawed and is not consistently populated across the DNOs.

416. The benchmarking analysis does not consider the differences in scale of interventions at secondary and primary substations. This fails to acknowledge the scope of the work is materially different and should be benchmarked separately.

417. Similar to load driven network reinforcement, the constraining asset will dictate the fault level capability. To demonstrate this point, some constraints will be resolved by replacing a short section of low rated cable at relatively low cost and others will require the replacement of a primary switchboard at a relatively high cost. Each intervention would constitute a single unit under the current metric, despite being fundamentally different, driven by different issues and incurring different costs.

418. In addition, inconsistent application of the reporting instructions for units is creating disparity. For example, some DNOs report replacement of an 11kV switchboard (consisting of 17 circuit breakers) as one unit, while other DNOs report the same solution as consisting of 17 units. This inconsistency leads to a wide discrepancy in unit costs which then makes it impossible to carry out any like for like comparisons.

419. Our recommendation is that the proposed works are assessed based on the engineering rationale presented in the EJPs. However, if the current approach is used, then the input data issues referred to above need to be fixed:

a. Primary and secondary interventions need to be disaggregated further.

b. Guidance needs to be refined to ensure all DNOs report consistent costs and volumes (this will require resubmission of datasets).

420. The current model uses an industry median cost based on ED1 and ED2 data. ED1 data should be discounted from the benchmarking due to the fundamental change in scope and volumes that we propose for ED2 as presented in our EJP.

421. As unit costs are calculated as a whole intervention, they do not account for shifts in investment strategy between price control periods. Driven by enabling greater LCT uptake we propose both higher volumes and unit costs for HV switchboards. This increase is not driven by inefficiency, yet it is penalised by the current modelling.

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

422. We do not agree with the proposed adjustments to account for outlier volumes data for ENWL and SSES. We believe that these adjustments are being made because of three factors:

a. Firstly, a fundamental flaw within the template leads to different activities being compared with one another;

b. Secondly, there is a difference in how the tables have been populated by DNOs; and

c. Thirdly, the adjustments are not being made consistently across all DNOs.

423. On our first observation, this flaw results in both primary and secondary switchboard interventions being treated as like activities. This is far from reality with the former costing orders of magnitude more than the latter to resolve.

424. Secondly, and as explained above, the data template requires both number of discrete assets and the number of switchboards as two separate volumetric measures. We believe that some DNOs have inflated the count of switchboards by counting them as individual circuit breakers which is not in line with the instructions and guidance. There is also the potential for double counting across innovative and conventional solutions. Both can result in apparent outliers but are in fact completely inconsistent with other DNOs.

425. Having reviewed the data submitted we believe the same proposed adjustments could be applied to other DNOs. We believe that the template should be modified to address the differences between primary and secondary network interventions. Then all DNOs should be asked to resubmit their data and checks made to ensure compliance with the instructions.

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

426. We do not agree with Ofgem's proposed approach to determining baseline allowances for connections. Specifically:

a. Ofgem should not rely on the sector median when defining its unit cost. Ofgem should use the sector average; and

b. Ofgem should recognise that with network utilisation increasing and available headroom reducing, it is now far more likely that new connections will trigger wider reinforcement, and that much more of the cost of this will now borne by the DNO following the final Access SCR decision. Hence Ofgem should rely on ED2 sector metrics (rather than ED1 and ED2), which better reflect this.

427. We also have concerns over the data that currently populates Ofgem's models. We set these out below.

Reliance on median to identify unit cost

428. Connection costs have a highly skewed distribution, in particular at higher voltages.

429. While the majority of connections will tend to be relatively straightforward to implement, a small number of projects will prove complex, and may trigger a substantial volume of reinforcement work. Northern Powergrid observes this skew in all of its historical data.

430. We expect this skew to become more pronounced as a consequence of Ofgem's recent Access SCR decision. As part of this review Ofgem has now decided to remove, in many cases, the requirement for the connecting party to pay for wider reinforcement costs. The outgoing policy of charging the customer for a share of the wider reinforcement will have stopped developers from making some of these more complex, highly expensive connections. Going forward, we

anticipate there will be more connections of this kind that trigger substantial work, and the cost will now be borne primarily by DNOs.

431. It is vital that Ofgem reflects on the underlying nature of connection costs and sets benchmarks that reflect this underlying skew. The simplest way to do this is to rely on the sector average, not the sector median.

Reliance on ED1 data which is likely out of date

432. During the ED1 period, we have been able to accommodate many connections on to our network without these triggering material reinforcement work. This will change going forward, as our network fills up and as the scale of connections (both in terms of size and frequency) increases as customers install a wide variety of LCTs.

433. The average cost of any given connection is likely to increase over time as a result. In light of this, it is wrong for Ofgem to set its unit cost allowance by reference to both ED1 and ED2. Ofgem should rely solely on evidence available for ED2, since this evidence will accurately reflect the appropriate conditions. The conditions that prevailed in ED1 will not be repeated.

Unit cost variation

434. Ofgem's assessment is based on a unit cost approach (we note that MPAN volumes have been accepted as submitted by each DNO). Ofgem uses a median industry £k/MPAN, over ED1 and ED2, as the benchmark unit cost for each connection type.

435. We are concerned that the unit costs underlying Ofgem's benchmarks are extremely variable across price controls and across DNOs. Therefore it may not be meaningful to apply a single benchmark unit cost without first understanding what is driving these differences. There is a risk that DNOs have taken inconsistent reporting approaches or used different planning assumptions. Ofgem should investigate this further to ensure that data is on a consistent basis and comparable.

436. The tables below show just two examples. For two different connection types ('single service LV' and 'HV end connections involving EHV work'), they show unit costs for each DNO across RIIO-1, RIIO-2, and both periods. They also show the median, mean, upper and lower quartile, as calculated by Ofgem. The figures highlighted in yellow (median across DNO and RIIO-1+2) are the benchmarks that Ofgem uses for each connection type. These tables show that Ofgem's benchmarks mask significant underlying variation across DNOs and time periods. As explained in our response to Q107, simply applying a mean or median across such figures may not be meaningful, as there may be inconsistencies in the data or genuine reasons for the variation.

	RIIO-1	RIIO-2	RIIO-1+2
ENWL	1.0	2.1	1.6
NPGN	6.0	51.3	27.4
NPGY	3.4	53.0	25.8
WMID	-	-	-
EMID	-	-	-
SWALES	-	-	-
SWEST	-	-	-
LPN	-	-	-
SPN	7.5	2.8	6.2
EPN	1.3	-	1.3
SPD	0.4	0.1	0.3
SPMW	0.7	0.1	0.4
SSEH	0.6	355.0	87.1
SSES	0.0	1,083.7	637.5
Median	1.0	27.1	6.2
Mean	2.3	193.5	87.5
Lower Quartile	0.6	1.6	1.3
Upper Quartile	3.4	128.5	27.4

Figure 9. Unit costs – single service LV connection

	RIIO-1	RIIO-2	RIIO-1+2
ENWL	59.1	-	59.1
NPGN	-	-	-
NPGY	33.5	71.6	53.5
WMID	509.7	337.1	391.5
EMID	1,344.8	743.3	1,130.0
SWALES	-	-	-
SWEST	1,070.3	2,847.6	1,818.6
LPN	4,268.9	3,726.6	3,988.0
SPN	754.8	815.4	782.3
EPN	2,859.9	1,306.1	2,234.2
SPD	-	-	-
SPMW	-	-	-
SSEH	424.7	244.9	324.8
SSES	1,019.1	1,443.6	1,212.1
Median	887.0	815.4	956.1
Mean	1,234.5	1,281.8	1,199.4
Lower Quartile	445.9	337.1	341.5
Upper Quartile	1,276.2	1,443.6	1,667.0

Figure 10. Unit costs – HV end connections involving EHV work

Consistency of service upgrades costs and demand driver adjustment

437. Ofgem currently carries out a 'reverse exclusion' to our connections costs, adding in Service Upgrades costs that we originally reported in table M13. These are additional costs associated with our higher planning scenario.

438. Ofgem contacted us on 15 August 2022 with a data request, "seeking additional data from DNOs for the development of the LRE volume drivers, in particular for LV services to enable better comparison of submitted costs and volumes and the breakdown of services in DNOs' forecasts."

439. Currently, Ofgem includes our higher planning scenario costs for all LREs. Therefore, when Ofgem calculates the demand driven adjustment using totex 3, the resulting adjustment for NPg effects a reduction from our higher planning scenario to the System Transformation scenario.

440. If Ofgem removes the reverse exclusion for connections, this will create an inconsistency between the scenario underlying our connections costs and our other LRE costs. The reduction in connections costs will have a relatively small effect within totex , meaning that Ofgem's demand driven adjustment will still be based on moving us from our (now slightly reduced) higher planning scenario to System Transformation. However our connections costs will be starting from a far lower scenario, meaning that the demand driven adjustment will be too large when applied to Connections.

441. Therefore, if Ofgem does decide to remove the reverse exclusion for connections, it is essential that it finds a way to scale down our demand driven adjustment for connections appropriately, or removes the adjustment entirely.

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

442. Yes, we agree with the proposed assessment for NTCC expenditure and acknowledge Ofgem's post publication correction of the core methodology document that confirmed the costs as being funded via ex ante allowances.

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

443. Our response is split to address the two component parts of Ofgem's proposed approach.

444. On volume assessment:

a. We agree with the principle that where a licensee has justified their volumes for an asset class then the submitted volumes should be allowed. However, we disagree with the approach that Ofgem has taken where if it has considered volumes to be partially justified, it has applied the lowest value from a set of three potential industry average measures to determine the allowed volumes of work. Further dialogue is required with Ofgem on the required level of volumetric justification if it has fallen short of the generic EJP guidance provided as part of the business plan guidance. The allowed DNO volumes also need to align with the submitted NARMs outputs that have been accepted by Ofgem – it is wrong to disallow volumes associated with delivering NARMs outputs, and not adjust those outputs accordingly.

b. DNOs can have legitimate reasons for delivering a different mix of work across a regulatory period, in order to manage the overall asset portfolio and balancing emerging assets risks. This can lead to variations compared to original business plan submissions for a regulatory period. Ofgem has used this variance as being evidence of a DNO's inability to deliver work and it is used to suggest that there is future delivery risk arising from historical investment decisions.

c. Where Ofgem considers that a DNO has only partially justified the volumes in some cases there is inconsistency in how at a licensee level the assets covered under a single EJP have been treated in the modelling. Ofgem should provide clearer reasoning for any disallowances. We welcome further discussion between ourselves and Ofgem.

445. On unit cost assessment:

a. We do not agree with the proposed assessment of unit cost.

b. There has been no consideration of incremental cost information we have provided that was aimed at giving further detail where our unit costs may be higher relative to other DNOs or our own historical costs. This incremental cost information was justified in the supporting EJPs and mainly relates to the provision of additional asset functionality or capacity to meet net zero. This was in line with the requirements of the Ofgem business plan guidance and sector specific methodology.

c. Ofgem has continued to use what they consider to be their expert view which is over a decade old. We appreciate this has been indexed up to modern prices, but it does not take into consideration the types and sizes of equipment we need to install as we build a network to achieve a net zero future. If an expert view of unit cost is going to be used, then it needs to be demonstrated that it is a credible unit cost for the ED2 period.

d. The proposed unit cost methodology does not consider individual licensee initiatives that may impact unit cost, discussed in detail in our EJPs. The methodology needs to take account of individual licensee proposals that provide additional benefits, which may be at a higher unit cost.

e. There are a number of manual overrides on unit costs that require clarification from Ofgem.

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

446. Our response is split to address the two component parts of Ofgem's proposed approach.

447. On volume assessment:

a. We agree that where a DNO has justified their volumes for an asset class then the submitted volumes should be allowed.

b. When Ofgem considers an EJP to be partially justified then the volumetric measure should consider the outputs that we are trying to achieve alongside the NARM data that we included in our submission. These concerns are the same as those detailed in our response to question 73.

c. Given the wide scope of activity covered by refurbishment activities across DNOs using an industry run rate is inappropriate for some asset categories (e.g. fluid filled cable and transformer refurbishment). The refurbishment practice of a DNO will be a function of their asset management strategy and the characteristics of their own asset base.

448. On unit cost assessment:

a. We do not agree with the proposed assessment of unit cost.

b. Given the range of activities that can be undertaken in a refurbishment scheme, using the replacement unit cost as an indicator for refurbishment unit costs is flawed. For some assets only refurbishment is appropriate in the period so there is no replacement activity on which to base the cost assessment. Therefore the modelling produces a result of a zero unit cost for refurbishment and this is clearly an unacceptable outcome.

c. The proposed unit cost methodology does not consider individual DNO initiatives that may impact unit cost, discussed in detail in our EJPs. The cost assessment methodology needs to take account of individual DNO proposals that provide additional benefits at a higher unit cost and make qualitative adjustments to reflect these.

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

449. We agree that asset replacement driven civil works should be linked to the asset replacement activities that drive them.

450. However, as with the other condition-based asset replacement and refurbishment, we believe that there should still be an element of qualitative cost assessment to take account of justifiable higher civil works costs, or where low-volume high-cost civil works skew the average unit cost. This is aligned with the principles used at ED1.

451. This is more prevalent at higher voltages, where the volume of works is less and the nature of the work may be more bespoke.

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

452. We do not agree with the proposed approach for benchmarking volumes associated with Condition Based Civil Works.

453. The allowed volumes have been adjusted to assume that all DNOs will have the same amount of interventions on their asset base for similar assets and we believe this methodology is flawed. The approach takes no account of the existing condition, location or the environments in which the substations are operating. There is variability in the type and construction of civil works used at substations, both within individual DNOs and between DNOs. While substation populations will be at different stages in their asset management lifecycle, as governed by the historical asset management policies used by DNOs.

454. We believe that a qualitative adjustment to the model outputs based upon the EJPs is necessary as this will provide the inputs for more meaningful disaggregated cost assessment that is intended to reflect the differences between DNOs. The EJPs along with associated SQs provide details of the strategies for each civil works element, along with a clear description of the condition data and the methodology that has been used to justify the volume estimations. The

EJPs provide detail that cannot be derived from a simplistic model alone. This is in line with the principles applied in ED1 cost assessment.

455. We believe the percentage intervention rates do not accurately represent the likelihood of required interventions for Northern Powergrid, particularly for HV Indoor and HV Outdoor substations. A condition driven civil works intervention is more likely at an indoor substation with multiple elements that could require replacement, compared with an outdoor substation that is likely to only need a single element replaced (e.g., a fence).

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

456. We do not agree with the proposed assessment approach for diversions because of the inconsistent treatment between volume and unit cost benchmarking that fails to assess the actual efficient cost for delivering this type of work.

   a. In the core methodology document Ofgem has concluded that volumes are not comparable due to substantial differences between DNOs, hence the decision to allow DNO forecast volumes for ED2. However actual and forecast unit costs also vary substantially across DNOs.

   b. As costs and volumes differ significantly it is highly likely that the scope of work for each activity is also not comparable across DNOs. The benchmark outcome is therefore incongruent with the allowed volumes.

   c. This results in giving some DNOs significant cost increases over the costs incurred in ED1, with zero challenge on the volumes forecasted and the total cost of the activity. How much a DNO needs to spend in this area is a function of the scale of the network, their location, and the economic activity within the area. This cost area would lend itself much more readily to a MEAV driven regression type cost assessment over a partial disaggregated assessment.

457. The size and scope for each diversion can vary hugely between DNOs, depending on geography, historical network configuration, asset management policy and deliverability. This can be seen in the variation between unit costs for each DNO at each voltage level. These variations are not solely the result of inherent inefficiency while delivering the same interventions but are a symptom of each DNO, and each network intervention, requiring a different solution.

458. We note that Ofgem has recognised the variation in unit costs between DNOs, however the solution of only using ED2 forecast volumes to calculate modelled costs does not adequately address the variances. The unit costs continue to vary significantly between DNOs rather than between price controls.

459. The volume of work that each DNO will need to undertake is not within the DNOs control but will be (at least in part) dictated by the volume of assets and the scale of the networks. The cost of the activities is in large part outside of the DNOs control as it is a function of the value of land, the financial loss a third party may incur because of the location of our assets or the scale

of the diversion. These factors will vary significantly from case to case and across the country, meaning they are unlikely to be comparable.

460. Due to the lack of comparability across volumes and unit costs we would suggest adopting a completely different, more high-level, approach.

461. We recommend a regression style approach using total historical costs from ED1 relative to a driver that captures company size, such as MEAV, establishing a median position and using that to project forward a suitable cost allowance for the ED2 period.

462. We believe that overall costs in this area will remain relatively stable from ED1 to ED2 and where a DNO believes this not the case qualitative assessments can be made based on the evidence provided rather than just being accepted and passed through.

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

463. Yes, we agree with the proposal to retain the ED1 re-opener mechanism for ED2 and to provide nil ex ante funding for rail diversions.

464. While we have not submitted costs in this area for ED2 we welcome the proposal to maintain the re-opener mechanism in the event that costs arise during the price control period.

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

465. We do not agree with Ofgem's proposed approach. It does not properly consider the inclusion of significant project expenditure that is material enough to warrant separate Engineering Justification Papers and also constitutes a large proportion of the costs in this category. There are 9 EJPs which justify expenditure in this table.

466. Our ED2 business plan included £20.5m of expenditure to fund the service elements (communications, data storage, information provision and fault location) for both equipment installed on the network in ED1 (carrying forward into ED2) and new equipment purchased in ED2, which accounts for approximately 22% of our total submission for CV11 IT & T. These costs are integral to our asset strategy to reduce overall cable investment and respond to a problematic asset base. Ofgem's disaggregated benchmarking approach has disallowed the majority of this investment. This is expenditure is directly linked to £17.7m of expenditure in table C7 STEPM (see response to Core-Q92), to fund the purchase of additional tools and instruments for low voltage cable fault monitoring and fault management.

467. A significant part of the disallowance arises from Ofgem's post-modelling qualitative adjustment in relation to its assessment of our related Engineering Justification Paper (EJP 10.2 - LV Technology). This post-modelling adjustment is not appropriate, as the underlying benchmarking technique (ratio analysis, using MEAV as the cost driver) is already disallowing costs above the benchmark level.

468. Conversely, EJPs that have been assessed as justified and have no post-modelling qualitative adjustment applied, have costs disallowed by the underlying benchmarking technique (ratio analysis, using MEAV as the cost driver) disallowing costs above the benchmark level.

469. Ofgem should, as a minimum, remove the existing post-modelling qualitative adjustment and should instead consider including a positive qualitative adjustment in order to allow the costs detailed in our EJPs related to this table.

470. We agree with the proposal to combine non-operational, operational, and business support IT&T costs given the overlap and inter-dependency between these three areas.

471. We agree with the use of MEAV as the cost driver, given its strong correlation with the cost pool, however we believe that the use of a) ratio analysis and b) a period ED1 + ED2 costs, are flawed for the following reasons.

a. Ratio analysis neglects to cater for the high proportion of fixed costs that are incurred for this cost area, and disproportionately benefits DNOs with a larger MEAV whilst it penalises DNOs with a smaller MEAV. We propose that regression analysis would instead recognise that there is a large, fixed cost component for IT&T, and would therefore result in a fairer comparison between DNOs.

b. The ED1 and ED2 time period for assessment fails to recognise the required DSO and digitalisation needs of the networks during ED2. Ofgem clearly articulate in Clause 7.390 of its Core Methodology that “costs are expected to increase substantially over RIIO-ED2 due to investments in data and digitalisation”. DNOs have responded appropriately to the need to transition to DSO and to digitalise operations, and subsequently there is a proposed step-up across all DNOs’ IT&T cost submissions when comparing ED1 to ED2. However, Ofgem has assessed the efficient cost benchmark based on the median of all DNO mean costs across both ED1 and ED2. The result of this disproportionately weights ED1 costs (i.e., 8 of 13 years = 61%) when determining the efficient ED2 costs, whilst not accounting for the step-up in costs between price control periods. We propose that only ED2 costs are used in the cost modelling, on the basis that ED1 costs are not appropriate when considering the data and digitalisation commitments for DNOs.

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

472. No, we do not agree with the proposed ratio benchmarking assessment for Legal and Safety costs. We believe qualitative analysis should be used to determine allowances instead.

473. A qualitative assessment would fairly reflect the variety of approaches needed to manage legal and safety driven risks across the different networks, while allowing important safety improvements to be completed at an efficient cost to customers.

474. There is a very weak relationship between the chosen variables used in the ratio analysis. The proposed method of using total Legal and Safety expenditure as a ratio of MEAV annually, which is then benchmarked against the industry median ratio to calculate allowances, is flawed and does not accurately or fairly determine allowances for this expenditure type. Regression analysis shows that MEAV only explains 2% of the variation in Legal and Safety costs. This is far too low; this driver should not be used to model efficient Legal and Safety expenditure.

475. Further to this, we believe that unit costs analysis would be flawed here too, as the volume and type of work involved is not universally undertaken across all networks. Where unit cost benchmarking and ratio analysis are not appropriate, we propose a qualitative assessment of the cost proposals.

476. It is clear from the submitted data by DNOs that there is a difference in approach for half of the DNOs, with one half proposing to complete very little and the other proposing to address much more in this category. There are two potential reasons for this, either:

a. Half of the DNOs have network specific factors, that mean that significantly lower volumes of work are required. In this case, penalising the remaining DNOs which have made different historical choices on their network only serves to reduce the safety of the network for operators and the public, without any assessment of the necessity of efficiency of the work being carried out; or

b. The work is being carried out by all DNOs but there is a difference in cost classification meaning that some DNOs may separate out these work volumes into Legal and Safety and others may cover the requirements via asset renewal work programmes. This approach of only addressing Legal and Safety issues via asset renewal would not adequately address the risks, as not all investment is aligned with assets and locations requiring asset renewal.

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

477. We agree with the principle of the proposed approach for assessing Overhead Line Clearance costs of using an industry median unit cost based on RIIO-ED1 and RIIO-ED2 data, complemented by an engineering review to determine volume adjustments.

478. The management of overhead line clearances is a specific legal obligation, as defined within ESQCR, therefore we believe there should be an exceptionally high bar to disallow volumes in this area. Our volumes are based on survey data of the network and therefore known issues that need to be rectified. We have high confidence in the costs and volumes we have proposed and agree with the outcome of the engineering review that has been undertaken.

Core-Q82: Do you agree with our proposed approach to assessing ESR cost?

479. We agree with the approach to assessing ESR costs; a qualitative assessment is the best option to determine allowances fairly.

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

480. We have commented on Ofgem's approach in our response to question 49.

481. We do not feel strongly how QoS is funded, whether by upfront allowances or incentivised via the IIS incentive mechanism, as long as adequate funding is made available to meet the level of performance desired by our customers at a cost they are willing to pay.

482. If ex ante QoS funding is not made available then we believe the IIS scheme is a package of components that need to work together to allow the same outcome. The package of components includes Ofgem ED2 targets, incentive rates, revenue caps and TIM.

483. The current incentive rate reduction proposed for ED2 needs to be sufficient to fund investment to close the gap between present levels of performance and the targets.

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

484. We agree with the proposed assessment approach for physical security.

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

485. We do not agree with the proposed approach for assessing Flood Mitigation costs of using an industry median unit cost based on RIIO-ED1 and RIIO-ED2 data complemented by engineering review.

486. The assessment is overly disaggregated resulting in benchmarks being set on very few volumes or costs that were incurred at the beginning of ED1. This results in benchmarks that are unlikely to be representative of the costs and/or work that is being proposed by the DNOs for ED2.

487. We suggest that a more high-level approach is adopted. Although levels of flood risk and programme maturity will also have a significant part to play, the volume of work will largely be driven by network scale.

488. All DNOs have been working to the same flood defence standard, and within that, all have agreed to the same target dates. Therefore a simple benchmark relative to company scale, for example MEAV, would be much more appropriate in assessing the total levels of spend for this activity. This could be combined with a qualitative assessment to capture company specific factors.

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

489. We agree with the proposed approach for assessing Rising and Lateral Mains costs of using DNO median unit cost based on RIIO-ED1 and RIIO-ED2 data complemented by engineering review.

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

490. Yes. We support Ofgem's approach to assessing WSCs.

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

491. We agree with Ofgem's approach for assessment of transformer volumes. However, we do not agree with the proposed use of the 'RIIO-ED2 expert asset replacement industry median unit cost' when determining the unit cost for transformers.

492. This is not appropriate given that the unit cost of transformers can differ significantly depending on:

   a. the size of the existing transformer;

b. the proposed size of the replacement transformer;

c. the choice of core technology; and

d. the aggregated cost when accounting for the transformer population to be replaced.

493. We propose that Ofgem adopts the same position as proposed for PCB pole mounted transformer unit costs (i.e., a licensee-specific unit cost to include tiered unit rates to accommodate upsizing, where appropriate and justified). The licensee-specific unit costs should cater for both 'upsizing' and choice of core technology (e.g., amorphous core technology) as both these factors are significant in the resulting losses performance that will be achieved.

494. We agree with Ofgem's approach for assessment of other costs in this category.

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

495. We agree with the proposed assessment approach for environmental reporting, with the exception of Oil Pollution Mitigation Schemes – Operational Sites.

496. The use of DNO median costs over the period of ED1 and ED2 for Oil Pollution Mitigation Schemes – Operational Sites takes no account of the different intervention types that will be deployed during ED2 when compared to ED1.

497. For Northern Powergrid specifically, we will be pivoting from relatively low unit costs interventions, e.g. spill kits or bund refurbishment, to higher cost interventions, e.g. bund replacement, with more invasive requirements for our civil structures, as detailed in our EJP.

498. Given the difference in work types for ED2, unit costs are not comparable between ED1 and ED2. We would support an approach that accepted DNO forecast costs as submitted (as per Ofgem's Core Methodology Document, paragraph 7.313).

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

499. We agree with the proposed assessment approach for PCBs. We believe it is appropriate that DNOs' own unit costs are being used as the benchmark, given that the nature of work and volumes vary substantially between DNOs.

500. We agree that an uncertainty mechanism is appropriate (for PMTs) allowing flexibility to accommodate the uncertain volumes of PMT replacements required for us to meet our obligations under the PCB regulations.

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

501. We are comfortable with Ofgem's approach to benchmark costs in this category against MEAV.

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

502. No. We do not agree with Ofgem's proposed approach. It does not properly consider the inclusion of efficient project expenditure that is material enough to warrant a separate Engineering Justification Paper and also constitutes a large proportion of the costs in this category.

503. Our ED2 business plan included £17.7m of expenditure to fund the purchase of additional tools and instruments for low voltage cable fault monitoring and management, which accounts for approximately 60% of our total submission for STEPM. These costs are integral to our asset strategy to reduce overall cable investment and respond to a problematic asset base. Ofgem's disaggregated benchmarking approach (that ignores interdependencies between cost categories) has disallowed the majority of this investment.

504. A significant part of the disallowance arises from Ofgem's post-modelling qualitative adjustment in relation to its assessment of our related Engineering Justification Paper (EJP 10.2 - LV Technology). This post-modelling adjustment is not appropriate, as the underlying benchmarking technique (ratio analysis, using MEAV as the cost driver) already disallows any costs above the benchmark level.

505. Ofgem should, as a minimum, remove the existing post-modelling qualitative adjustment and should instead consider including a positive qualitative adjustment in order to allow the costs detailed in our LV Technology EJP

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

506. We agree with Ofgem's approach.

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

507. Yes, we agree with the proposed assessment approach for HVPs.

508. We agree that in the event of not being able to accurately benchmark costs that a qualitative assessment is the best option to determine allowances fairly.

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

509. Yes. We see merit in there being some clear and unambiguous criteria for defining a HVP. We believe it should be based on the ED1 threshold and we used this as an assumption in building our plan submission.

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

510. We do not agree with the cost assessment approach for Faults and ONIs.

511. The modelled costs are based on a regression model using Faults and ONIs volumes as two independent variables at total level with total costs as the dependent variable. We believe this approach does not produce a fair outcome for all DNOs as it does not appropriately account for the mix of Fault and ONI activity carried out by each DNO. To be more specific:

   a. The approach benefits DNOs who have a higher proportion of low-cost type activity within Faults or within ONIs. For example, LV supply restoration by switching only.

   b. The approach disadvantages DNOs who have higher proportion of high-cost type activity within Faults or within ONIs. For example, LV underground cables (non-CONSAC).

512. This means the approach is heavily weighted to rewarding those DNOs with a favourable network composition, which cannot be changed efficiently in the short term, rather than the efficiency of costs by activity. This fails to recognise the inherent network factors the that individual DNOs face and a DNO will either "win or lose" based on their forecast deviation from the average fault volume mix.

513. The effect of this is seen most strongly for NPg Yorkshire, which performs poorly in the model due to having significant volumes of higher cost faults (LV underground non-Consac and street lighting) relative to the DNO average. Despite delivering that specific activity efficiently, it receives a significant penalty. For example:

a. Ofgem's fault cost regression model results in an overall DNO average unit cost for all fault types in ED2 of £2.1k.

b. The industry average unit cost for LV underground cables (non-CONSAC) in ED2 is £4.4k.

c. Therefore, a DNO that delivers higher than average volumes (of this type) are, on average, at a disadvantage of £2.3k per unit.

d. The NPg Yorkshire forecast ED2 unit cost is £3.4k per unit for LV underground cables (non-CONSAC) fault, which happens to be the 2nd most efficient DNO for the activity. The combination of our high forecast fault volumes in this category and a cost per fault that is greater than the average unit cost across all faults, Yorkshire receives a significant negative cost adjustment.

e. When modelling the above for all Fault types, our analysis shows that the total cost adjustments by DNO (normalised input vs assessed costs) are strongly linked to the mix of volumes, significantly more so than any cost efficiencies (or inefficiencies) which DNOs are showing.

514. These Yorkshire fault rates are a result of historical policy decisions on our underground asset base and cannot reasonably be adjusted in the near term.

a. Proactively replacing the worst performing underground cable types would be hugely inefficient compared to the approach of responding promptly to faults as they occur and replacing them over their natural replacement cycle.

b. The Yorkshire street lighting volumes are impacted by the historical arrangements with local authorities. One model being that the network operator provides a supply to every individual streetlamp with the second basic model being that the street lighting authority installs and owns a street lighting main and requests a single point of supply to that main. Yorkshire has a higher mix of the former and so receives considerably more faults.

515. We propose that the assessment approach should be changed given the evidence that the mix of fault types has a significant impact on how DNOs perform in the model. We would support either:

a. Modelling at a more disaggregated level taking account of LV underground and street lighting specifically with a unit cost-based model, or

b. A network specific factor adjustment for both, to take account of the historical reasons for the high volumes.

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

516. We do not agree with the assessment approach used in the models for ENATS 43-8 as it does not reflect the approach described in Ofgem's methodology document.

517. We agree with the proposed assessment approach outlined in the core methodology: the use of physical cuts and inspections as the drivers. This differs from the assessment approach utilised in the model, which uses spans affected as the driver. We would support the alignment of the models with the approach proposed in the core methodology.

    a. The relationship between spans cut and submitted costs is stronger than the relationship between spans affected and submitted costs. Regression analysis shows that spans cut explains 76% of the variation in ENATS 43-8 costs, whilst spans affected only explains 54% of the variation.

    b. The submissions made by each DNO were structured such that the activity driver (spans cut, spans inspected and LiDAR) was given careful consideration and realistic costs allocated to proposed work against each of these categories. The utilisation of spans affected within the model ignores the detailed work that has gone into the submissions.

518. We agree with the methodology of assessing ETR132 work at a total network level as opposed to at a disaggregated voltage level with the use of overhead network length or run rates to determine activity volumes. We also agree with the selection of the industry median for the benchmark unit cost.

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

519. We agree with the approach given the difficulty in forecasting the costs and volumes of such events. The provision of funding after the event removes the subjective element of forecasting these uncertain costs.

520. We have experienced first-hand with Storm Arwen in November 2021 that the scale of a 1-in-20 event in cost terms can be extreme. The event in Northern Powergrid Northeast has been our only 1-in-20 event in the DPCR5 to RIIO-ED1 period at a cost of £10.5m (in 2020/21 prices) to March 2022. In comparison, our forecast for RIIO-ED2 was £10.0m in total for Northern Powergrid.

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

521. We do not agree with the proposed approach to using MEAV ratio benchmarking, with the industry median as a benchmark, based on ED1 and ED2 data.

522. Submitted costs are driven by inspection and maintenance cycles set out in policy. We believe that using the average industry relationship between costs and MEAV is an unreasonable method as these costs depend on the profile of inspection and maintenance cycles and company policy, which are designed to ensure our assets are fit for purpose, compliant with legislation, safe, secure, and efficient.

523. No allowances are given for changes in policy between RIIO-ED1 and ED2 driven by legislation, safety issues or technological advances. The methodology assumes that inspection and maintenance policies and cycles remain the same between regulatory periods.

   a. A number of new requirements have been identified for ED2 to ensure ongoing compliance with legislation. For example, the need to establish a service termination inspection regime as a result of the move away from conventional metering to smart metering. We believe that adjustments should be made to account for these necessary changes in policy.

   b. Technological advances have led to the introduction of additional costs into the repairs and maintenance category for ED2. These include an enhanced inspection programme for poles through the use of the Thor hammer, a programme of works for the application of PFTs (Perfluorocarbon Tracers) in cables and the use of self-healing cable additives. The proposed methodology does not facilitate the introduction of these programmes. Our business strategy for ED2 has assumed that, although there are costs within this category associated with these technologies, the efficiencies achieved as a result within other categories far outweigh the costs. Without inclusion of these projects within the Inspection, Repairs and Maintenance arena, it is unlikely that the assumed efficiencies will be realised, significantly driving up costs in other areas, such as asset replacement.

524. We would support an approach which makes a qualitative adjustment to take account of these additional costs associated with policy changes.

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

525. We do not agree with the proposed assessment approach for NOCs other.

526. The use of median unit costs for RIIO-ED1 and ED2 for substation electricity takes no account of the current outlook for future energy prices. We do not agree with the proposal to utilise DNOs' median unit costs based on RIIO-ED1 and ED2 data because:

   a. DNOs will attempt to secure the best terms they can to supply electricity to their substations on an individual basis. Over the course of the last 10 years we have faced significant volatility in the wholesale electricity market which is clearly exacerbated in the current economic climate. This volatility is completely outside of the control of DNOs and therefore trying to establish a benchmark using historical data is flawed. In light of recent wholesale energy market volatility we would support the use of a funding mechanism to cater for exceptionally high energy prices and to protect consumers should the price of energy fall during the price control period.

b. The element that is within the control of DNOs is the amount of electricity consumed within the substation, not the unit price paid.

c. Ofgem should investigate approaches which measure and promote efficiency and therefore seek to benchmark volumes, not cost, in this area. For example, Ofgem could consider an industry benchmark based upon the MWh consumed per substation by voltage. This benchmark consumption could be combined with a reopener to cater for volatility on unit price.

527. The use of MEAV ratio benchmarking for dismantlement makes no allowances for specifically identified projects. We agree that the proposal to utilise a MEAV ratio benchmarking based on RIIO-ED1 and ED2 data is a reasonable way to set baseline costs, however it takes no account of specific one-off projects that have been identified within this category for ED2. Consideration should be given to allowing costs in addition to the baseline where DNO's have identified and justified specific projects for ED2.

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

528. We do not agree with the cost assessment approach for the Smart Metering Rollout. The proposal is to provide only an ex ante allowance using a median unit cost-based model. This replaces the ED1 approach of an ex ante model plus an uncertainty mechanism with a volume driver. We do not agree with this approach on three key points:

a. The uncertainty mechanism should be maintained. There remains a degree of uncertainty around how successful the roll out will be to 2025. We can forecast the number of installations but whether (or when) suppliers will meet the targets is beyond our control.

   i) There is a large backlog of completed interventions which (as per the RIGs) we have not claimed allowances for, as smart meters have not yet been installed. The proposed approach would see us lose this allowance if these are not claimed by the end of ED1 whilst the mechanism is still in place. This is also beyond our control.

b. The model makes significant adjustments to the submitted intervention volumes by applying a 3% industry median intervention rate to the forecasted installations rather than using the actual intervention volumes forecasted. This disproportionately benefits DNOs that have a low historical intervention rate and have submitted an optimistic view of the installations to the end of the roll out period. A subjective forecast view by DNO of what suppliers will do should not drive the cost assessment.

c. Applying the 3% median intervention rate to forecasted installations does not work fairly as a 'one size fits all' approach for volumes. It is not within the DNO's control to the same extent as unit cost. Applying the median penalises DNOs with a higher intervention rate, backed by historical data, often due to the historical condition of equipment on the network.

529. Based on the above we would support an approach which adopts one or more of the following:

a. The ex ante allowance is provided but the uncertainty mechanism is maintained.

b. The same rollout scenario (forecast installations) is applied to all DNOs based on a percentage of customer numbers. If we are assuming a successful rollout this would be close to 100%.

c. An intervention rate aligned with an individual DNO's actual submissions is used.

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

530. We support Ofgem's approach in this area to benchmark costs using MEAV as a cost driver.

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

531. We support Ofgem's approach in this area to benchmark costs using MEAV but believe that a group basis would be more appropriate for benchmarking Core Business Support costs.

532. At ED1, Ofgem assessed these costs at group level, rather than DNO level, but has moved to a DNO basis at ED2 in order to 'exploit a larger dataset' since it has moved to a regression approach. Assessing Core Business Support costs on a group basis is more reflective of how these costs are incurred, which should be prioritised over trying to create a larger sample.

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

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

534. Ofgem does not carry out a comparative benchmarking exercise for streetworks, recognising that, *"as permit and lane rental charges can vary substantially between local and highway authorities, we do not think streetworks is appropriate for comparative benchmarking between DNOs."* Instead, it calculates the growth in each DNO's underlying activity volumes, by comparing activity volumes in each year of ED2 to a 'base year' (for which it uses the average of 2019-2021). This provides, for each year of ED2, a percentage uplift (or reduction) in activity volumes relative to the base year, which Ofgem uses to uplift (or reduce) costs in the base year.

535. The activity volumes appear to be based on connections, LRE and NOCs workloads – the model outcome is highly sensitive to this dataset, and we have been unable to determine how it is established. It also fails to recognise the fact that changes in streetworks costs can be driven entirely by external factors and not all changes in cost necessarily relate to changes in volumes of physical work.

536. Assuming the inputs represent the volumes of physical work we face and plan to carry out, this approach is nevertheless highly problematic for NPg specifically, because our growth in workloads since 2019-2021 does not reflect our growth in streetworks costs over the same period, which have faced significant increases driven by external factors. The charts below show that we have faced huge growth in streetworks costs between the middle and end of ED1. For example, while Ofgem calculates that our activity volumes for NPgN increase by 22% between

the end of ED1 and the base year, our CV streetworks costs increase by 260% in this period, far higher than any other DNO (followed by NPgY at 77%).

537. This is in part driven by increased permit activity volumes which, for example, grew by 500% from 2019 to 2021. This increase is not driven by a fivefold increase in the volume of work we have undertaken but is driven by councils' adoption of full permitting schemes and the introduction of the Department for Transport's 'Street Manager' system. The most significant external factor driving the costs has been the increase in Permit Condition Costs aimed at trying to reduce disruption for road users.

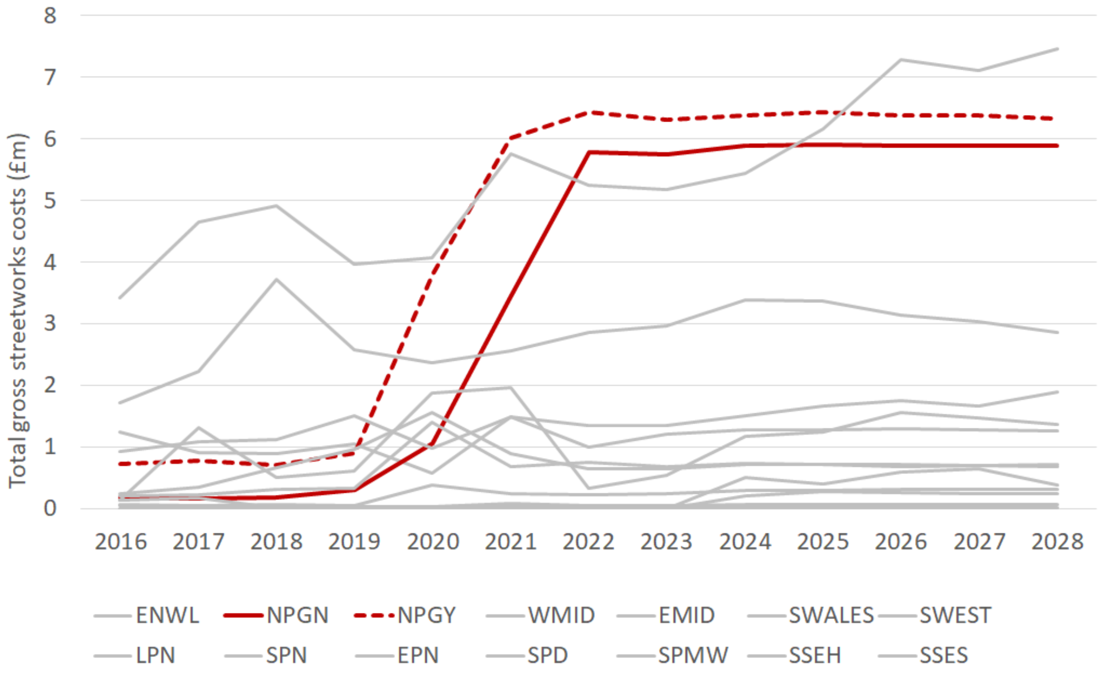

Figure 11. Streetworks costs, BPDT sheets CV

538. Ofgem recognises in its core methodology that, "streetworks is an emerging area of spend for many DNOs and is therefore likely to look different in future years compared to the earlier years of RIIO-ED1." Given this, our view is that Ofgem should apply adjustments on top of its trend analysis where there is evidence that streetworks costs have or will change significantly due to external factors. We would welcome the opportunity to work with Ofgem to establish a more appropriate way of assessing this cost area.

539. Ofgem should also remove the ratchet within its streetworks model, which currently selects the lower of each DNO's submitted costs and Ofgem's modelled costs. In general, we disagree with the use of ratchets as these create poor incentives for companies to submit ambitious plans. In addition, the use of ratchets within the disaggregated models means that DNOs receive no reward in cost categories where Ofgem views their forecasts to be efficient but are penalised in categories where they are viewed as inefficient. This means that the outcome of Ofgem's

disaggregated model suite is based on a cherry-picking approach, applying an efficiency challenge that is unbalanced and unreasonably stretching.

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

540. Since Ofgem did not provide companies with a common decarbonisation planning scenario on which to base ED2 business plans, despite repeated requests for this during Cost Assessment Working Groups and bilateral meetings, Ofgem has failed to gather business plan data on a comparable basis. We therefore recognise the need for Ofgem to ensure that its benchmarking models have the effect of setting allowances in line with Ofgem's preferred uptake scenario.

541. However, since Ofgem's demand driven adjustment is applied after benchmarking, this adjustment is likely to double count with other aspects of Ofgem's cost assessment process, i.e. Ofgem's earlier benchmarking steps will have benchmarked away some of the higher volumes of work inherent in plans that embody a high level of LCT uptake, meaning that a second full demand driven adjustment will be at least partially duplicative.

542. Ofgem should either switch off the demand driven adjustment, or if it is retained, take steps to mitigate the risk of double counting. We set out the issues below, covering totex and disaggregated modelling separately.

Application of demand driven adjustment to totex models

543. In Ofgem's totex benchmarking process, the glide path is calculated using the efficiency scores from the three totex models, before the demand driven adjustment is applied. However, as set out in our response to Q64, totex 1 and totex 2 do not control properly for planning scenario differences, and so differences in plan scenarios will be picked up in these models as differences in efficiency. As a result, the derivation of an efficiency frontier that relies on totex 1 and totex 2 will already go some way towards imposing a common plan scenario, that will be built into the glide path benchmark.

544. After Ofgem has calculated the glide path, it applies the demand driven adjustment to costs. This demand adjustment, based on totex 3, makes an adjustment to costs to fully account for differences in LCT uptake.

545. Ofgem then applies the glide path on top of this. This leads to a process in which a partial correction for differences in scenario (arising as a result of dependence on totex 1 and totex 2 in setting the efficiency benchmark) is combined with a full adjustment for differences in scenarios through the demand driven adjustment.

546. This leads to a clear conceptual double count embedded within the totex benchmarking models, albeit it is not straightforward to quantify the extent of this double count.

547. As explained in our answer to Q64, Ofgem should abandon totex model 1 as it is not fit for purpose and should only use totex 2 if material changes are made to the definition of the capacity released variable to resolve its existing problems and the risk of double count with the

demand adjustment can be mitigated. In any event, it should rely far more heavily or entirely on totex 3.

548. If totex 1 and/or totex 2 are retained, then a solution for the partial double count is needed but becomes more complex. Ofgem would need to scale down its demand driven adjustment, as applied to totex modelled costs, to account for the fact that it double counts with the glide path benchmark.

Application of demand driven adjustment to disaggregated models

549. Ofgem applies the demand driven adjustment to the LRE components of the disaggregated modelling, i.e. connections, primary reinforcement, secondary reinforcement, fault level reinforcement, and new transmission capacity charges.

550. However, in several of these areas Ofgem makes use of substantial volume disallowances as part of its disaggregated modelling. While it is not possible to infer in all cases the basis on which volumes have been disallowed, it is highly likely in our view that at least some of NPg's disallowed volumes – in some cases a high proportion – are in effect a consequence of Ofgem imposing a less ambitious uptake scenario on our business plan, which embodies a more ambitious uptake scenario. This again creates a significant risk that for these categories, Ofgem is, in effect, making two duplicative adjustments for underlying scenario.

551. In our view, the simplest remedy to this problem would be to remove the demand driven adjustment from the disaggregated analysis. The only other remedy to this is for Ofgem to engage with NPg on the detail of its disaggregated analysis to ensure that there is no scope for double count by either:

   a. restoring some volumes in specific disaggregated models and then applying one and only one demand adjustment; or

   b. being clear that certain volumes disallowed within disaggregated modelling are disallowed in order to impose a less ambitious scenario, and hence there is no need to then also apply a demand adjustment.

552. Below we set out more detailed concerns we have over specific disaggregated models.

553. We consider that there is no rationale for applying the demand driven adjustment to primary reinforcement and fault level reinforcement.

   a. Our submitted primary reinforcement schemes were selected as being required across all decarbonisation pathways to meet the Ofgem business plan guidance requirement of identifying 'certain' costs.

   b. Fault level reinforcement is driven by existing constraints on the network and is not influenced by any forecast information that may vary across decarbonisation pathways.

554. Furthermore, within primary reinforcement, Ofgem's volume assessment involves comparing DNO ratios of forecast MVA additions and forecast MVA over firm capacity. It then brings DNOs

in line with a common benchmark ratio. However, DNOs with a high ratio may be planning for higher LCT uptake beyond ED2 (i.e. years which are not included in Ofgem's analysis) to provide a net zero ready network as opposed to adopting a short-term planning approach that will create barriers for net zero. Therefore, Ofgem's volume adjustment will include some adjustment for differences in plan scenarios and will double count with the demand driver adjustment. (We note that Ofgem has not made volume adjustments in fault level reinforcement).

555. The demand adjustment should therefore be removed entirely from primary and fault level reinforcement.

556. Within secondary reinforcement, Ofgem's volume assessment compares DNO workloads per LCT, and sets the benchmark at the mean ratio (with a ratchet). Although Ofgem is controlling for LCT numbers, it does not take account of the fact that DNOs will face different types of constraints and challenges as a result of decarbonisation, and will therefore likely disallow some legitimate work volumes driven by decarbonisation.

557. We discuss this in more detail in our response to Q107, where we also discuss the importance of engaging with engineering evidence and DNO-specific challenges when carrying out disaggregated analysis.

558. The demand adjustment should therefore be removed from secondary reinforcement, or certain volume disallowances should be reinstated.

559. The likelihood of double counting is reinforced by the materiality of the disallowances made by Ofgem in the disaggregated modelling. Figures 10 and 11 below show the percentage of our submitted costs in LRE categories that have been disallowed in the relevant disaggregated models. These disallowances are very significant, as high as 87% for primary reinforcement in NPgN. Overall, around half of our reinforcement costs have been disallowed.

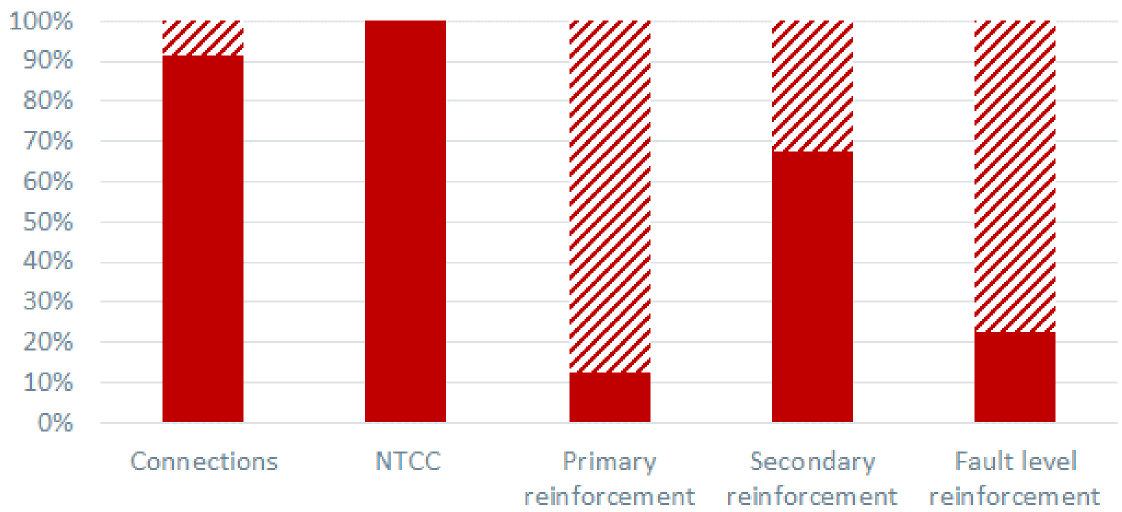

Figure 12. Percentage disallowances through disaggregated modelling (hashed sections), NPgN

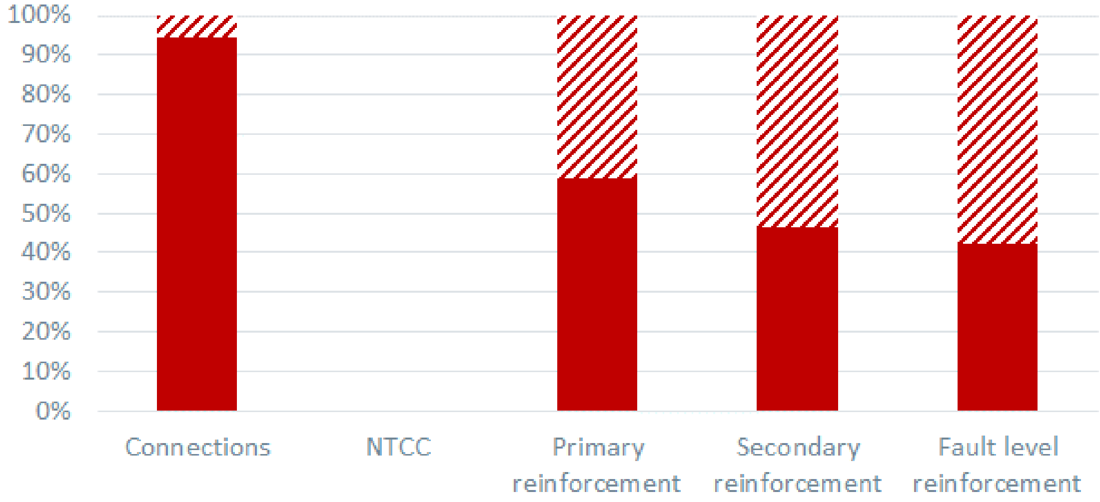

Figure 13. Percentage disallowances through disaggregated modelling (hashed sections), NPgY

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

560. We agree with Ofgem's view that a high evidence bar would be needed to make adjustments to the benchmarking analysis for quality of service.

561. We welcome Ofgem's changes to target-setting in the IIS scheme – particularly in light of Ofgem's disallowance of NPg's bespoke price control deliverable (see our response NPg-Q2) and to generally disallow QoS funding (see response to Core Q49). This adjustment avoids the distortion to the IIS targets arising from funding in prior periods provided to other networks and levels of network automation.

562. More broadly, we have engaged actively on the topic of whether to adjust benchmarking approach through the Cost Assessment Working Group (CAWG) and therefore do not have anything further to add here. Ofgem has signalled its intention to continue working on this topic through the CAWG, and we will continue to engage actively. We note in particular that if another DNO seeks to submit new evidence bilaterally with Ofgem which would change the benchmarking approach adopted at the DD on QoS, this evidence would need to be shared with the CAWG in advance of the Final Determinations.

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

563. We do not agree with Ofgem's approach to combining the totex and disaggregated benchmarking models.

564. Ofgem's current approach places 50% weight on Ofgem's view of efficient modelled costs from the totex models (16.7% on each), and 50% on the disaggregated models. Our view is that Ofgem should instead place more weight on its approach to estimating efficient totex . We do not think that it is appropriate for Ofgem to place significantly more weight on its disaggregated

modelling than on any of its totex models. This view is reinforced because of the severity of the issues within the disaggregated modelling, which we discuss further below.

565. Should Ofgem agree with us that it should abandon totex 1 and rely far more heavily, or entirely, on totex 3 (as set out in our answer to Q64), then we would propose that Ofgem places 67% weight on totex (either totex 3, or totex 2 and 3) and a maximum of 33% weight on its diaggregated modelling.

566. This approach would partially mitigate the impact of the problems within Ofgem's disaggregated models. However, Ofgem must make further changes to address these issues. We set out the overarching issues below, and have covered more specific issues within individual models under our responses to Q65-Q104.

Ofgem does not engage with the engineering evidence, a critical input to disaggregated modelling

567. We set out briefly in Q64 why we strongly favour totex modelling over disaggregated modelling. If disaggregated modelling is to be used, it should only serve as a lesser-weighted, secondary source of evidence to cross-check totex modelling results.

568. Proponents of disaggregated modelling typically argue that this kind of modelling enables a regulator to examine and assess detailed engineering evidence about each network, providing a more detailed insight into what is driving differences in overall DNO efficiency on a line-by-line basis.

569. However, Ofgem's disaggregated modelling fails to engage properly with much of the carefully constructed engineering evidence that we have provided to support our well-justified business plan. It instead applies all manner of arbitrary judgements, mechanistic benchmarks, averages (where no meaningful average exists), and ratchets to overwrite well-evidenced engineering judgement and strike out needed volumes of work. All this without coordinating appropriately with our Engineering Justification Papers (EJPs).

570. Ofgem states that it has reviewed all 676 EJPs that it received from DNOs, taking account of factors such as the overall need for the investment and the efficiency of the proposed engineering solutions. However, it appears that Ofgem has ignored EJPs in its LRE expenditure assessments and in non-load categories, primarily used the EJPs to justify the use of the lowest industry average metrics for volume disallowances, rather than allowing volumes where fully justified.

571. Furthermore, the disaggregated data is very noisy, and in many areas simple inspection of the data shows that it is subject to clear inconsistencies across DNOs i.e. there are models where it is obvious that Ofgem is not benchmarking like with like. Much of this is likely to be driven by DNOs' different planning approaches, but reporting inconsistencies are also an issue in some areas. Rather than identifying these data issues and engaging with DNOs to resolve them, Ofgem has applied broad-brush sector averages to this data, leading to benchmarks that are not meaningful because they average across different planning approaches and assumptions.

572. Ofgem needs to engage fully with the engineering detail we have provided – we will provide further evidence as required – and work to resolve obvious data consistency issues. A substantial programme of work is needed over the autumn to ensure the disaggregated modelling is made fit for purpose.

573. An example of these inconsistencies can be seen clearly in the secondary reinforcement data. In order to calculate volume adjustments within the secondary reinforcement disaggregated model, Ofgem calculates ratios between DNO forecasts of different intermediate outputs (MVA of capacity released, km of circuit reinforcement, number of service cable interventions), and their forecast LCT volumes. These ratios are shown in the three charts below. It is evident that the range in the ratios is very wide across DNOs, including across companies that operate within the same ownership group.

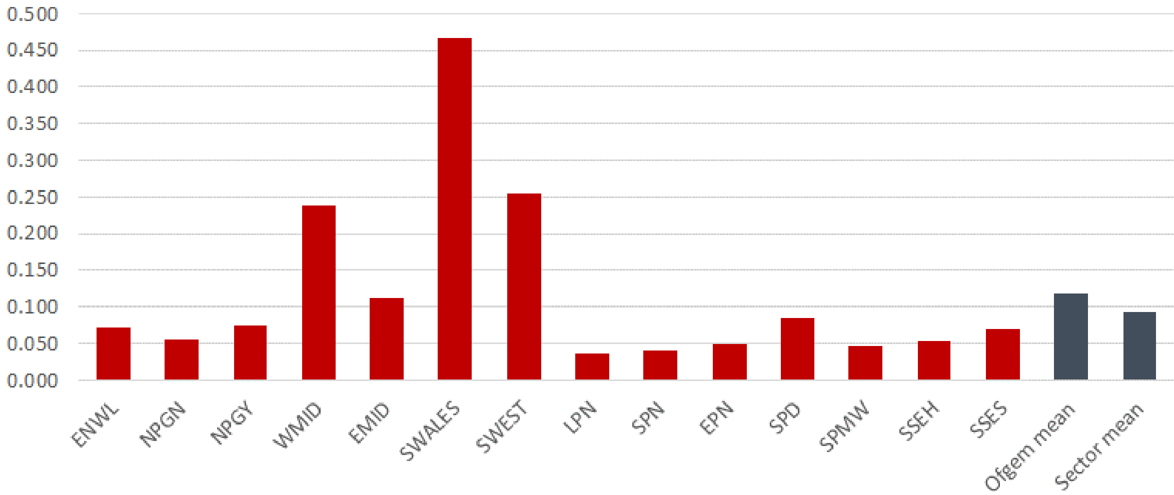

Figure 14. Forecast capacity released (MVA): LCT connections (MW)

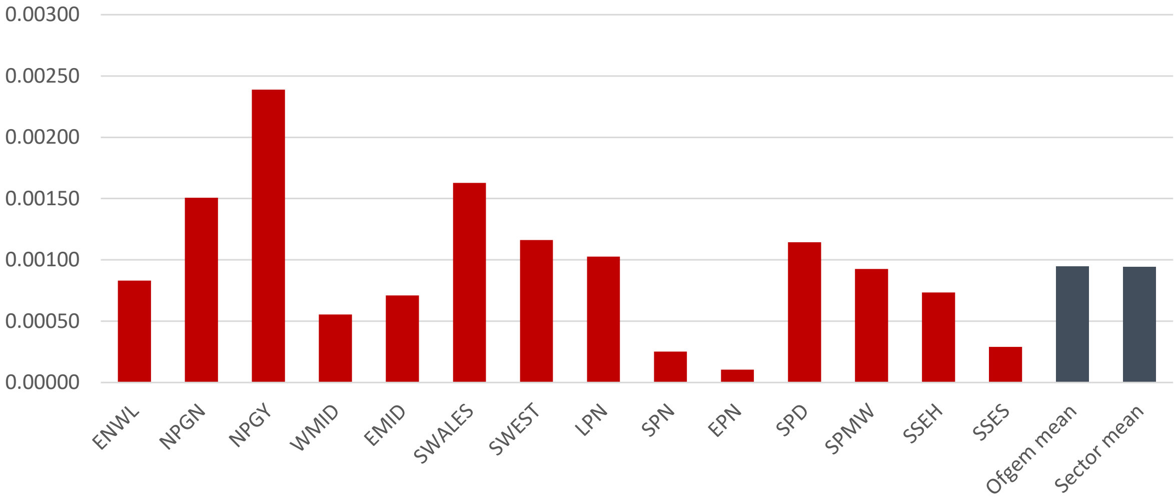

Figure 15. Forecast circuit reinforcement (km): # LCT connections

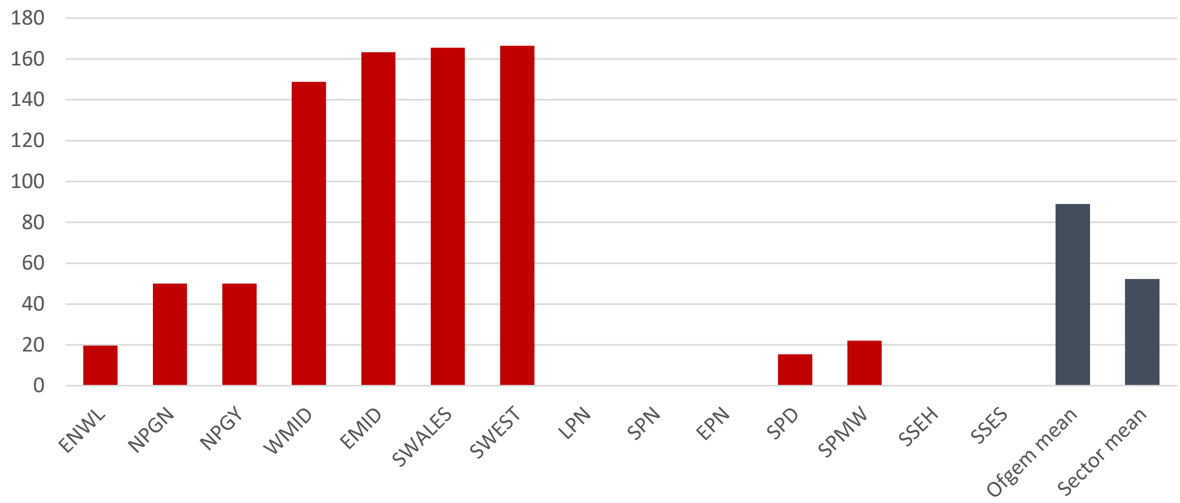

Figure 16. # of EVs & HPs: # service cable interventions

574. These charts reflect significant differences in how DNOs expect they will need to invest in their networks to manage increases in LCT numbers – e.g. some DNOs expect to release far more capacity per LCT connection than others, some plan to carry out more circuit reinforcement per LCT connection, and some expect to need to carry out more service cable interventions. These are not minor differences; for example, our NPgY forecasts represent 23 times more kilometres of circuit reinforcement per LCT connection than EPN.

575. This should raise a red flag to Ofgem. DNOs face very different challenges as a result of decarbonisation, particularly when looking at granular cost areas. There is simply no reason to suppose that there is some underlying 'average' level of work per LCT uptake that all companies should be capable of matching in these areas. DNOs are evidently adopting different strategies to address the specific challenges that they expect to face in their region (and may also be making different assumptions about how those challenges will affect them). Rather than engaging with DNOs to understand the drivers of these differences, Ofgem simply averages across these incomparable figures to set a benchmark and applies a ratchet on top of this (setting each DNO's ratio at the lower of the mean or the DNO ratio).

576. The result is that Ofgem disallows any workloads above the mean 'output per LCT', without understanding whether there are legitimate engineering reasons for networks to need to respond in different ways to LCT uptake. Ofgem's approach is clearly wrong.

Resulting allowances have been 'cherry-picked' across incomparable plans in each category

577. Ofgem's modelling approach leads to a cherry-picked outcome across the disaggregated model suite, that no real-world company can hope to achieve. This is because:

   a. Ofgem uses EJP evidence only to disallow work volumes and ignores this evidence where it provides a reason not to disallow volumes through the mechanistic benchmarking model.

b. It takes broad-brush averages across a noisy and inconsistent dataset where no meaningful concept of an average exists, leading to meaningless benchmarks that are often driven by outliers in each individual cost category.

c. It uses ratchets in some cost categories, taking the lower of benchmarked costs and submitted costs. This ignores the fact that companies need to make trade-offs across cost categories, and also disincentivises companies from submitting ambitious plans in future. At ED1 Ofgem recognised the drawbacks of using ratchets and significantly reduced its use of them between DD and Final Determinations.

d. In some models, Ofgem picks and chooses between assessment methods to select the method that provides lowest allowances at a very granular level. In particular Ofgem's asset replacement model uses a range of different volume assessment methods, selecting a different method for each asset category and each DNO based on what gives the lowest value (see our response to Q73).

e. In some models, Ofgem benchmarks data that is simply incomparable.

   i) In some cases this is due to Ofgem's methodology. For example, in primary reinforcement it assesses investment solutions and flexibility solutions together, without accounting for the fact that the two sets of solutions deliver benefits over very different time periods. The low unit costs of flexibility solutions (reflecting their temporary nature) biases the resulting benchmark downwards. This is discussed further in our response to Q65.

   ii) In other cases this is due to data issues. For example, in fault level reinforcement we believe that DNOs have reported data inconsistently, with some DNOs recording work at a more granular level than requested in the guidance (e.g. at circuit breaker level, rather than switchboard level). This means that volumes and unit costs are incomparable, and biases the benchmark unit cost downwards. This is discussed further in our response to Q69.

The overall disaggregated benchmark has been set beyond the frontier DNO

578. The overall result of these deficiencies in Ofgem's approach to disaggregated modelling, including multiple aspects of cherry-picking, is that every single DNO receives a cut in the disaggregated modelling, relative to submitted costs. This means that Ofgem's efficiency benchmark is being set beyond the frontier DNO.

579. This is shown in figure 15, which shows the ED2 efficiency scores based on the disaggregated modelling. These scores are calculated by dividing each DNO's submitted costs by its disaggregated modelled costs. The fact that every DNO has a score above 1 indicates that every DNO's modelled costs are lower than its submitted costs. Even the 'frontier' DNO, SPMW, receives a cut.

	ED2 Efficiency Score
ENWL	1.13
NPGN	1.11
NPGY	1.05
WMID	1.11
EMID	1.15
SWALES	1.07
SWEST	1.15
LPN	1.20
SPN	1.14
EPN	1.12
SPD	1.06
SPMW	1.02
SSEH	1.24
SSES	1.16

Figure 17. Efficiency Scores

580. The stylised chart below (Figure 16) illustrates (not using actual data) the position of the resulting efficiency challenge, relative to a reasonable catch-up efficiency challenge (for example the upper quartile). For simplicity, this is illustrated in the context of regression modelling, but the principle applies generally across different methods of cost benchmarking.

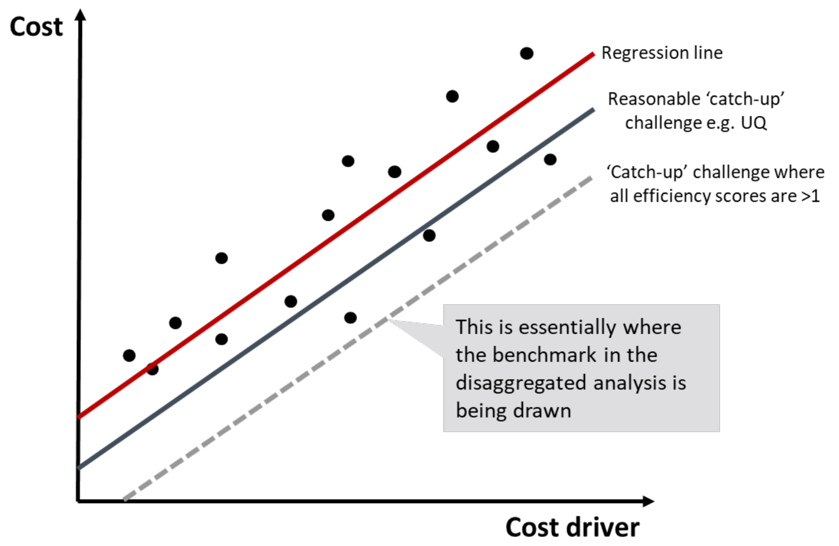

Figure 18. The efficiency challenge

581. As explained in our response to Core-Q108, regulators must set the efficiency benchmark at a more conservative level than the efficient frontier to reflect that any benchmarking approach will be imperfect and will capture all manner of uncontrolled factors and 'noise' not just

differences in efficiency. Ofgem's overall application of disaggregated modelling fails in this regard, constituting a clear error.

582. In the ED2 context, the inconsistency of company plans and data issues already discussed limit confidence in the ability of the models to perfectly identify the efficient frontier. Setting the benchmark not just at the frontier level of efficiency, but beyond this level, is highly inappropriate and goes against regulatory theory and practice.

583. Ofgem must take steps to remedy this outcome.

584. First, Ofgem must address the issues around cherry-picking set out earlier in this response. It must also address the model-specific errors and issues raised in our responses to Core Q65-Q104.

585. It should then revisit the level of efficiency challenge being set in its disaggregated modelling, by determining whether the most efficient few DNOs are receiving at least their submitted costs through the disaggregated modelling (as this would be indicative of an efficiency benchmark within the efficiency frontier). If this is not the case, and the efficiency challenge has not moved to a reasonable level, Ofgem should shift the efficiency benchmark to the upper quartile or glide path level, in the same ways as it does for the totex models.

586. In the case of the disaggregated models, this would involve a shift up from the current beyond-frontier benchmark level, rather than a shift down from the mean level (as for the totex models). This can be seen from the table below, which is the glide path based on the disaggregated efficiency scores shown above, as calculated by Ofgem. As can be seen, the glide path is always above 1 for the disaggregated models, meaning that it would result in an uplift to modelled costs.

	2024	2025	2026	2027	2028
Glide Path	1.08	1.07	1.06	1.06	1.06

Figure 19. glide path based the on disaggregated efficiency scores

587. Applying the glide path (or upper quartile) to the disaggregated modelling results can be easily done by including the results from the disareggated models in Ofgem's calculation of the glide path catch-up efficiency challenge, and by applying the resulting glide path to the disaggregated modelled costs as well as the totex modelled costs. [This is consistent with Ofgem's approach at ED1.]

The demand adjustment must also be reduced or removed

588. Finally, as explained in our response to Q105, there is no rationale for applying the demand adjustment to primary reinforcement and fault level reinforcement, and this should be removed. Furthermore, it is likely that the demand adjustment double counts with the cherry-picking approach to disallowing costs, and our view is that this should be partly or entirely removed from the remaining disaggregated models to which it is applied, to avoid double counting.

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

589. We do not agree with Ofgem's proposal to move to a significantly more stretching catch-up challenge compared to its approach at RIIO-ED1.

590. A key consideration when setting the level of catch-up efficiency should be the robustness of the benchmarking model(s) used. All benchmarking models are subject to measurement error, data comparability issues, noise, missing variables, and other sources of bias. This means that no benchmarking exercise can perfectly establish the 'true' efficiency frontier. To account for the imperfection of benchmarking models, it is standard regulatory practice to set the benchmark level at a more conservative level than the measured efficiency frontier to account for this. Failure to do so creates a material risk that cost allowances will be set at an unreasonably low level that almost no network will be able to achieve.

591. Standing UK regulatory practice has been to rely on the performance of the upper quartile entity to set a target that imposes an appropriate degree of stretch, while balancing the risk that targets end up being unduly influenced by inherent and unavoidable model weaknesses.

592. Ofgem should therefore only move to a tighter efficiency benchmark than the established upper quartile approach if it has strong evidence that the robustness of its models has improved relative to ED1.

593. However, to the contrary, we consider that Ofgem's models are less robust than at ED1 for a number of reasons as set out in our other cost benchmarking-related question responses, but most importantly as a result of just how different the planning scenarios embodied in different DNOs' business plans are. This is a consequence of Ofgem failing to provide DNOs with a consistent planning scenario. This makes the input data that Ofgem uses in its models far less comparable than was the case at ED1. For this reason alone, the challenge faced by Ofgem in its benchmarking (in terms of controlling for reasonable differences between DNOs' costs) is far harder than at ED1.

594. The differences in underlying planning scenarios leads Ofgem to rely on its novel 'demand driver adjustment' to remedy the issue. However, the demand driver adjustment has serious flaws, as explained in our response to Q105, and cannot be expected to fully address the inconsistencies. The demand driver adjustment also relies on totex model 3 accurately informing the size of the necessary adjustment, which adds more burden on the models to precisely capture the drivers of cost differences.

595. Ofgem provides four main reasons for moving from the upper quartile to the glide path efficiency benchmark. We provide our views on each of these below.

Consistency with gas distribution

596. First, Ofgem says that its proposed approach is consistent with its approach in the gas distribution sector. Consistency of approach is not a sufficient justification in itself, particularly

given that the two sectors have different contexts. For example, the gas distribution sector does not face the same degree of challenge around LCT uptake planning assumptions.

597. Furthermore, Ofgem's decision to use a glide path at GD2 was appealed by SGN, and the CMA's decision not to overturn the glide path acknowledged that "[SGN] has shown that GEMA had only limited evidence for setting a target which was more onerous than [the upper quartile]", but ultimately counterbalanced this with the limited materiality of the move from upper quartile to glide path, stating for example:

   a. "[I]t is important to note that it was not disputed that the effect of the choice of efficiency benchmark was small for the GDNs in RIIO-2. Focusing specifically on the impact on SGN, … around £2.8 million or 0.11% of its baseline totex ."

   b. "…GEMA's preferred approach, of using a glide path to the 85th percentile, is in practice in this case only marginally tougher than the upper quartile"

   c. "…weighing these matters up… GEMA's decision to use the data it had to support a marginally tougher target in the circumstances of this case was justifiable… it cannot be said that GEMA stepped outside its margin of appreciation."

598. The materiality of Ofgem's decision is significantly larger in this case, at £20m for NPg, and £158m for the sector. This represents about 0.7% of industry allowances, which is over six times larger than the impact on SGN referenced by the CMA. It is also possible that the impact could become significantly larger after corrections are made to the model suite.

599. We therefore do not agree that the choice of efficiency benchmark at GD2 is a precedent with which Ofgem should seek consistency at ED2. We also note that SGN's appeal raised concerns that Ofgem's move could set a precedent for future price controls. The CMA stated, "We do not agree with this view. Our decision should not be seen as indicating any preferred starting point for efficiency benchmarks. Regulators must always consider the case-specific circumstances and set the benchmark at a level appropriate for the case." This again reinforces that it is not appropriate for Ofgem to simply seek consistency with GD2.

600. Finally, it is relevant to note that the CMA found that Ofwat's decision to move beyond the upper quartile at PR19 was not justified because there was not enough evidence of improved model robustness. Therefore, there is also relevant precedent against such a move where the evidence to support it is limited.

Totex price control

601. Second, Ofgem says that the DNOs have been operating under a totex -based price control for two price review cycles, increasing Ofgem's confidence "that DNOs have had the opportunity to adapt their businesses to this alternative framework and that differences in cost performance revealed through our benchmarking can increasingly be attributed to genuine differences in efficiency."

602. It is not clear why adaptation to a totex price control would make benchmarking more accurate, or why differences in cost would now be more attributable to differences in efficiency.

Materiality

603. Third, Ofgem argues that the difference between the 75th and 85th percentile is relatively small, particularly when applied as a glide path to the 85th percentile. This is not correct. As stated above, the difference between the 75th percentile and the glide path amounts to £20m for NPg, and £158m for the sector. This figure may also increase once errors in the model suite have been corrected, as described above.

604. The change is also significant in terms of what it means for which DNOs are setting the glide path. The upper quartile is set by the 4th and 5th ranked DNOs in the sector, while the 85th percentile is set by the 2nd and 3rd ranked DNOs, which represents a significant shift. It is worth noting that this is not the case for the gas distribution sector, which has 8 licensees, meaning that both the upper quartile and 85th percentile are set by the 2nd and 3rd ranked licensees (but the 85th percentile is set closer to the 2nd ranked licensee).

Modelling approach

605. Fourth, Ofgem states that it has used a range of models, "including models that include capacity released as a cost driver. This means that our models take account of the reinforcement requirements individual DNOs have indicated are needed in their Business Plans and which may reflect factors that can be challenging to control, eg degree of network utilisation or characteristics of individual distribution areas, in a relatively small data set."

606. Our view is that the use of capacity released as a cost driver in totex 2, and as a component of the CSV used for totex 1, does not make Ofgem's model suite more robust than at ED1. Firstly, the capacity released data is subject to significant inconsistencies and deficiencies as explained in our response to Q64. Second, the use of capacity released is attempting to control for differences in planning scenarios used by DNOs, an issue that did not previously exist. Even if capacity released were to capture such planning differences perfectly, this would simply leave Ofgem's modelling suite capturing reasonable differences between companies as well as it did at ED1.

607. Given the issues with Ofgem's modelling suite and the inconsistencies in the DNOs' planning assumptions, our view is that Ofgem should retain the upper quartile efficiency benchmark. We do not consider that there is any evidence that the modelling approach is more robust than at ED1 and can support a tighter benchmark, and to impose a harsher frontier would be an error.

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

608. We do not agree with Ofgem's approach to RPEs. First, we do not agree with Ofgem's decision to index RPEs. Indexation to other sectors or the wider economy adds to the risks facing energy networks. While the provision of ex ante allowances means we still need to manage the risk of

RPEs being higher than allowed for, indexation using imperfect indices creates yet another dimension of risk around the variation in those indices. We set out this view first in our response to Ofgem's T2 and GD2 methodology consultation, and then in our response to the SSMC.

609. Second, if Ofgem does use RPE indexation, our view is that the recommendations put forth by CEPA, and adopted by Ofgem, lead to a risk of undercompensating DNOs for RPEs. This is due to four specific flaws in CEPA's analysis:

a. CEPA unjustifiably applies an RPE allowance of zero to cost categories that it deems to be low materiality and to the Other cost category.

b. CEPA's process for selecting benchmark indices fails to discriminate effectively between benchmark indices and therefore is excessively reliant on regulatory precedent.

c. CEPA does not update the notional cost structure to reflect the DD allowances, instead relying on a cost structure derived from DNO business plans.

d. CEPA combines the specialist and general labour cost categories into a single category that represents 63 per cent of totex for the notional efficient DNO.

610. In addition, NERA could not reproduce CEPA's RPE forecasts using its method as described, which means that the initial allowance Ofgem provides for RPEs may be inaccurate.

611. We set out a brief overview of these flaws below, and the recommended solutions, but more detail can be found in NERA's report, 'Response to RIIO-ED2 DD on Real Price Effects', commissioned by the ENA. We agree with the findings set out in that report.

CEPA unjustifiably applies an RPE allowance of zero to cost categories that it deems to be low materiality

612. CEPA deems that Plant & Equipment and Transport cost categories have low materiality, because each constitutes less than 5% of the totex of a notional efficient DNO. The 'Other' cost category is also excluded because CEPA says it cannot determine the materiality of the variation between the RPE index and CPIH (since no index was used to set an RPE allowance for that cost category at ED1).

613. In total, the affected cost categories make up 12% of totex for a notional efficient DNO, which is material. In the extreme, if the cost base was broken into small enough pieces, no cost category would pass the materiality hurdle, even though RPEs in the aggregate could be very material.

614. Our view is that, in line with NERA's recommendations, Ofgem combine Plant & Equipment and Transport into a single cost category (which would exceed CEPA's materiality threshold), and set an RPE for this category using the index "BCIS PAFI plant and road vehicles (90/2)". We also consider that Ofgem should set an RPE for the Other cost category using an appropriate index. Several options are set out in NERA's report.

CEPA's process is excessively reliant on regulatory precedent

615. Rather than following a sequential framework for index selection as it claims, CEPA's process is heavily reliant on regulatory precedent. As a result, the final set of indices selected by CEPA is identical to the set used at ED1 (other than for Plant & Equipment, where CEPA does not set an RPE).

616. Ofgem should expand its chosen indices for labour and materials to the larger basket of indices proposed by NERA. There are a number of other indices that perform similarly well against CEPA's stated criteria and should be included to reduce the risk of exposing DNOs to an index and cost mismatch.

CEPA does not update the notional cost structure

617. For both its materiality assessments and its calculation of the totex RPE allowance, CEPA uses a notional cost structure derived from DNO business plans. This does not take account of disallowances made by Ofgem. To ensure that the totex RPE allowance reflects an efficient DNO cost structure, DNOs should be given the opportunity to submit revised cost structures to be used to calculate the notional cost structure.

CEPA combines all labour costs into a single category

618. CEPA combines the general and specialist labour cost categories into a single category, meaning that 63% of DNOs' costs are being treated as a homogenous category facing common price pressures. However, it is not obvious that these costs grow at the same rate. This approach is also inconsistent with CEPA's approach to index selection and with regulatory precedent.

619. These cost categories should be accounted for separately, recognising the different price pressures they face.

CEPA's RPE forecasts could not be reproduced

620. NERA has not been able to reproduce CEPA's RPE forecasts based on its described methodology. It may be possible therefore that the initial allowance provided for RPEs is incorrect. Ofgem should provide CEPA's underlying workings in a form that is replicable.

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

621. We do not agree with Ofgem's proposed approach to setting the ongoing efficiency assumption or the level of challenge applied i.e. 1.2% per annum. Ofgem, and its advisor CEPA, have made a number of errors in their approach.

622. Ofgem is proposing to layer an unprecedented ongoing efficiency challenge on top of baseline allowances that have already been materially reduced relative to business plans, during a very challenging period which will be critical to the delivery of net zero. Ofgem's approach appears to be based on placing substantial weight on just one data point out of 48 estimates provided

by CEPA, combined with unevidenced speculation about how the context for ED2 might impact achievable productivity rates for DNOs.

623. We support the conclusions reached by both NERA and Frontier Economics, who have been commissioned by the ENA to review Ofgem and CEPA's approach. In short, NERA identify the following errors inter alia:

a. It is wrong to rely solely on Value Added (VA) measures of Total Factor Productivity (TFP) if the resulting productivity estimate is applied to the whole of totex.

b. CEPA has made a series of methodological choices that biases the EU KLEMS results upwards relative to its previous analysis. This includes the new inclusion of the ICT sector; and the changes to time-horizon relative to CEPA's recent approaches. No new evidence is provided that would justify these changes in CEPA's approach.

c. For Ofgem to cherry pick the highest estimate in the entire sample of 48 estimates provided by CEPA demonstrates evident bias in the approach. There is no justifiable reason to place sole weight on the single data point and essentially no weight on the rest. Ofgem and CEPA say that all of CEPA's EU KLEMS estimates are relevant and are given at least some weight – but this cannot be true while Ofgem simultaneously reaches a final point estimate of 1.2%.

d. In relation to the assessment of qualitative factors, CEPA and Ofgem both disregard or downplay a number of issues that would point to a lower point estimate, with no evidence beyond "a cursory rule-of-reason assessment" as NERA describes it. Some of these aspects are dismissed on the basis of being too uncertain. CEPA and Ofgem then point to two other highly uncertain qualitative factors which would (in their view) lead to higher productivity figures. Despite being at least as uncertain as other factors which were dismissed, Ofgem nevertheless gives these two factors significant weight and prominence in its reasoning. This approach is manifestly biased, unreasonable and wrong.

624. The 1.2% figure chosen by Ofgem therefore looks to have been produced by an exercise of data mining and selective reasoning, rather than a serious and balanced consideration of the evidence.

625. Further, the Frontier Economics paper identifies clear parallels between the approach and reasoning Ofgem has used for ED2, and that used for the 'innovation uplift' in GD2/T2 and the Smart Grid Benefits adjustment for ED1 – both of which were overturned on appeal to the CMA. Many of the same errors in approach from both of those appealed decisions have been repeated again in the ED2 DD.

626. For example, Ofgem and CEPA both make repeated reference to innovation funding to justify their decision, but essentially ignore all the errors of doing so that were pointed out by appellants and the CMA in the GD2/T2 appeal. In contrast to what CEPA appears to suggest, the fact that Ofgem now only relies on this qualitatively does not serve to mitigate those errors even remotely. Placing qualitative weight on an erroneous assumption is still an error. Nor is it

mitigated simply because we now cannot observe precisely what numerical value Ofgem would remove from its 1.2% target if Ofgem were to drop its qualitative reliance on innovation funding.

627. One of the errors of Ofgem's reliance on innovation funding is the likelihood that it creates the same double counting of cost disallowances that was found to have occurred in both the SGBs appeal and the innovation uplift appeal. CEPA has again advised Ofgem it needs to be cautious of this double counting risk. Ofgem appears to accept that double counting will have happened but has ignored CEPA's advice, stating that it was not possible to quantify the extent of double counting because of inconsistency in data reported by the DNOs. However, Ofgem never required the DNOs to report on cost savings using a consistent method. Whether or not these savings have been reported consistently, they can be expected to be in the business plan cost forecasts, and therefore to have been imposed widely across the sector baselines via Ofgem's benchmarking.

628. Since the DD was published, Ofgem has confirmed bilaterally with us that its statement that we had not reported required information on innovation benefits was incorrect (see Ofgem's DD NPg annex page 33). We also had no record of the 'recent request' Ofgem referred to (see response to Q8) which Ofgem has since clarified and to which we have now responded. Our business plan clearly identified £24m of NIA cost savings so far in the period 2015-23 period (page 21) plus wider benefits captured in the £263m of net savings from innovation in ED2 (page 152), as well as providing a detailed breakdown of the sources of these benefits (innovation strategy appendix 2, pages 29 and 34), and detail on innovation benefits within network investment (Costs in Detail annex, pages 53 – 55).

629. We note that this was just one of the errors confirmed by the CMA for both the GD2/T2 appeals and NPg's ED1 appeal, but other errors found by the CMA in those appeals equally to Ofgem's ED2 DD. We also note that Ofgem's reference to information asymmetry (para 7.476) is highly reminiscent of Ofgem's approach in attempting to introduce an outperformance wedge in the cost of equity for RIIO-GD2/T2, which was also roundly dismissed by the CMA. Ofgem should have engaged with the evidence the DNOs and their advisors put forward in supporting their business plan submissions on productivity, which in NPg's case was entirely transparent. If Ofgem was unsure about the evidence/reasoning used by the DNOs, it was within Ofgem's gift to make enquiries given the materiality of the parameter. Ofgem's appeal to information asymmetry as a reason to disbelieve the evidence put forward by the companies amounts to nothing more than a cursory ad hominem response.

630. The combination of all these factors further serves to support Frontier's conclusion that investors will likely perceive that Ofgem has made repeated attempts to arbitrarily 'goal seek' an outcome of 1.2%. This is highly damaging for investor confidence and for consumers. As Frontier's paper sets out, the CMA has unambiguously affirmed the need for regulatory decision-making – particularly on key and highly material parameters – to be robust and evidence based. The speculation, conjecture and assertion which Ofgem has now almost entirely reverted to in the ED2 DD simply does not constitute proper evidence that would meet the CMA's test.

631. It is also clear that Ofgem has not even followed CEPA's advice when selecting an extreme point estimate. Aside from the likely double counting which CEPA has warned about (discussed above), CEPA also recommended that Ofgem should only consider a target of 1.2% if Ofgem had evidence that (i) the average historical figures calculated from EU KLEMS significantly underestimate achievable ongoing efficiency, (ii) that network companies will be able to achieve efficiencies closer to more dynamic competitive sectors, and (iii) that technological transformation will be further supported by the provision of innovation funding from Ofgem to DNOs over the past decade through various innovation mechanisms. None of these three criteria set out by CEPA appear to have been actually evidenced by Ofgem – instead Ofgem resorts to speculative, unevidenced assertions.

632. We refer the reader to the NERA and Frontier Economics paper for a full discussion of these issues, which we do not repeat further here.

633. For the FD, Ofgem should adhere to the economic evidence at hand supports an Ongoing Efficiency target of between 0.3 and 0.8 per cent.

Additional compounding error

634. In its DD, Ofgem has compounded the ongoing efficiency challenge starting from the year 2021/22. However, the BPDT input template was set up for the index to begin from 2023/24. Therefore, when we submitted BPDTs that excluded our productivity assumption, this was only based on excluding a value compounded from 2023/24 onwards. Consistent with Ofgem's BPDT template, we did not strip out the productivity that was baked into our baselines in the years prior to 2023/24.

635. Ofgem therefore either needs to start compounding from 2023/24, or find a way to strip productivity relating to 2021/22 and 2022/23 out of costs for all years from 2021/22 to 2027/28 prior to benchmarking. Anything else will create inevitable and erroneous double counting between the benchmarking analysis and the productivity implementation.

636. This may be an area of potential inconsistency between DNOs' business planning processes which Ofgem will need to investigate if it does want to continue compounding productivity from prior to the year 2023/24.

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

637. We strongly disagree with Ofgem's disaggregation methodology. The proposed methodology is flawed, irrational and at odds with the available evidence.

638. Ofgem's DD method uses DNOs' submitted planning scenarios to allocate totex allowances across cost categories. The result is a misallocation of our efficient costs that shifts around £140m of our allowances out of cost categories where Northern Powergrid is demonstrably efficient into the 'variant' secondary reinforcement baseline. This means that around £140m of our efficient allowances will not be funded under any scenario, as we explain below.

639. Ofgem must correct this misallocation by disaggregating allowances based on proportions from the disaggregated modelling.

640. Ofgem disaggregates final allowances across cost categories in order to set certain volume driver, PCD and UIOLI allowances. As Ofgem recognises, the disaggregation "does impact the proportion of totex that is funded ex ante versus in variant (at-risk) totex "[13], which is the reason why it is critical that the disaggregation accurately captures the amount of efficient allowances needed in ex ante categories versus 'variant' categories. However, despite recognising the importance of a reasonable allocation of cost, Ofgem has failed to develop a method that achieves this.

641. Ofgem's current approach to disaggregation uses a proportional split of costs based on DNOs' normalised submitted costs. Ofgem's rationale is that this approach is "most reflective of plans for RIIO-ED2 and how [DNOs] expect to spend their allowances."[14] This reasoning fails for two reasons. First, it fails to recognise that the split of allowed costs is structurally different from the split of submitted costs, owing to the effect of Ofgem's benchmarking which will disallow more costs from cost heads where a given DNO is found to be less efficient. Second, it fails to recognise that LRE funding will be driven by outturn levels of LCT uptake and workloads delivered, not DNO plans or expectations.

642. It is important to be clear on certain key steps in Ofgem's cost assessment process, to demonstrate why there is a structural difference in the split of costs based on submitted costs and allowances:

a. Ofgem benchmarks our submitted costs, and includes in this the LRE costs associated with our relatively high uptake planning scenario.

b. Ofgem's benchmarking process then disallows costs across various categories, but makes disproportionately large disallowances to our LRE costs, mainly through volume adjustments. For example, Ofgem's disaggregated modelling disallows £167m worth of secondary reinforcement volumes for NPg.

c. Ofgem also makes significant demand driver adjustments to attempt to bring DNO allowances in line with a consistent planning scenario.

d. Ofgem then disaggregates final allowances based on the submitted costs described in (a) above.

643. The result of this process is that Ofgem allocates excessive allowances to LRE, reflecting our high planning scenario, despite having disallowed the costs associated with this high scenario, as a result of steps (b) and (c) above.

[13] Core Methodology Document, paragraph 7.480

[14] Core Methodology Document, paragraph 7.485

644. To correctly account for Ofgem's view of the costs necessary to meet a consistent planning scenario, Ofgem should use cost proportions based on disaggregated modelled costs (post workload adjustments and demand adjustments) to disaggregate allowances.

645. Figure 18 below shows a comparison of the allowances that Ofgem allocates to secondary reinforcement based on submitted cost proportions (grey bars), versus a corrected allocation based on disaggregated modelled costs, which far more accurately captures Ofgem's view of the efficient level of cost in each cost head (red bars). Most DNOs have excess allowances allocated to secondary reinforcement under Ofgem's method [15], but this is particularly pronounced for NPgY, due to the very large disallowances Ofgem has made within secondary reinforcement. The total impact for NPg is around £140m of excess allowances in secondary reinforcement, with these allowances being drawn out of other cost categories.

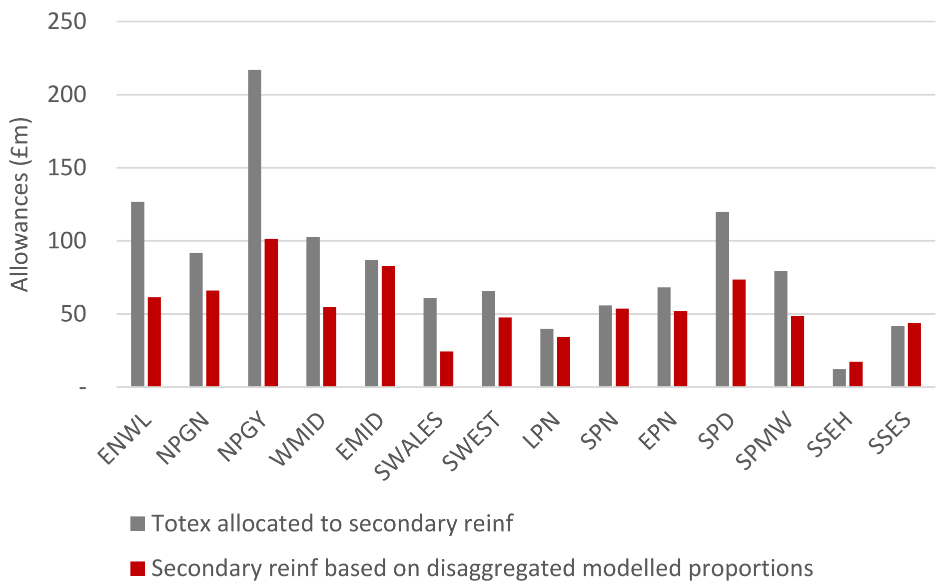

Figure 20. comparison of the allowances allocated to secondary reinforcement based on submitted cost proportions vs corrected allocation based on disaggregated modelled costs

646. This over-allocation of allowances to secondary reinforcement is highly problematic because of Ofgem's proposal to fund baseline allowances for secondary reinforcement as 'variant allowances', meaning they can flex down as well as up depending on outturn workloads, and because of the interaction with the secondary reinforcement volume driver. These factors mean that the misallocated allowances are in fact 'lost' under any outturn scenario because:

[15] The impact goes in the other direction for SSE, but this is still driven by a discrepancy between SSE's planning scenario and Ofgem's allocation of disallowances across cost categories.

a. they are associated with a high uptake scenario and, since secondary reinforcement allowances are 'variant', they will not be funded if a low or even central uptake scenario materialises; and

b. if a high uptake scenario does materialise, the secondary reinforcement volume driver should have provided the additional funding for this, meaning the misallocated allowances displace around £140m of volume driver funding.

647. These allowances have been drawn out of other cost categories which have already been subjected to efficiency cuts through the benchmarking, meaning that if Ofgem persists with its flawed method we will be severely underfunded in these areas (for example closely associated indirects). It is crucial therefore that Ofgem allocates allowances in a way that is consistent with the planning scenario it has imposed as a result of its benchmarking methodology, by using disaggregated cost proportions.

648. Applying a method of disaggregation that uses submitted costs in any way will lead to erroneous mis-allocation of allowances. Ofgem should not attempt to remedy this by using a blend of disaggregated modelling cost shares and DNO submitted cost shares. This would still interfere with the volume driver and would not solve the underlying problem, i.e. Ofgem has imposed a markedly different planning scenario in its baselines, and the split of costs found in company submissions, that embody a different planning scenario, are therefore entirely different with those that should be found in baselines. Allocation of allowances based on the disaggregated model cost proportions alone is the only appropriate method for Ofgem to apply.

649. Ofgem's flawed method of disaggregating totex allowances also has a knock-on impact for its calculation of capitalisation rates for totex allowances, leading Ofgem to apply incorrect rates.

650. We understand Ofgem calculates DNO capitalisation rates by taking the natural capitalisation rates (opex/capex split) submitted by each DNO across cost categories, and weighting these together using submitted cost proportions. Again, these proportions do not reflect the effect Ofgem's benchmarking has on the structure of allowances. The result is that NPgN's capitalisation is around two percentage points lower than it should be, and NPgY's is around five percentage points lower.

651. Most DNOs are affected by this issue to some degree (some by as much as six percentage points). The only DNOs not affected are ENWL, SSEH and SSES, who have submitted the same natural capitalisation rates across all cost categories. This is likely to be an error as the capex/opex split cannot be exactly the same across cost categories and should be corrected.

652. To remedy this issue, Ofgem should again use the disaggregated modelling outcomes to calculate capitalisation rates.

Finance Annex

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

653. We broadly agree with the approach of using a trailing average of the iBoxx GBP Utilities index as a method for estimating the cost of debt, given that this average captures the relevant market rate for both new and what was then the appropriate market rate for embedded debt, and should therefore reflect this aspect of the efficient debt cost for the sector over time. Given the way the iBoxx series are constructed however, it will not provide any allowance for issuance costs (for either new debt or those incurred historically when embedded debts were issued). It is right therefore that Ofgem allows a further 25 bps uplift to account for additional costs of borrowing.

654. However, it is still not clear to us that Ofgem's 25 bps allowance for issuance costs captures two points raised in our business plan submission regarding issuance costs.

    a. The reality that Northern Powergrid's bonds have been issued at a small discount to face value as a result of the coupon being "snapped" to the nearest 1/8 of a percentage point.

    b. The fact that a number of historical bonds were issued at a low coupon because they benefited from a credit wrap that secured a AAA credit rating. In essence then these bonds will (all other things equal) lower the core cost of debt allowance as a result of taking on higher issuance costs elsewhere (the credit wrap) which are not explicitly allowed for.

655. Ofgem must work with the sector to explore this issue, gathering the necessary data from the sector promptly and ensuring an appropriate adjustment is made to its estimate of issuance costs.

656. Also, while we welcome Ofgem's recognition (through its infrequent issuer premium) that not all licensees will be able to issue debt at the same rate owing to their size, we believe that the 6bps uplift for the infrequent issuer premium should be greater.

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

657. We do not agree with the method that Ofgem proposes to use to determine RFR.

658. Ofgem proposes to set RFR by reference to ILGs alone. This is out of line with established regulatory finance best practice, best practice that was reflected in the CMA's recent PR19 determination.

659. The CMA explored thoroughly the academic and market evidence available on how best to estimate RFR. It set out clearly the reasons why the traded price of ILGs (and hence their yields)

contains a convenience premium. The immediate consequence of this is that reliance solely on ILG yields to determine RFR will provide an underestimate of RFR.

660. As the CMA explained in its PR19 determination, setting RFR based on both ILGs and the yields on high quality, AAA corporate debt would provide a clearly superior way of estimating RFR.

661. We recognise that the CMA was willing to afford Ofgem a sufficient margin of appreciation during the RIIO-2 appeals to determine that Ofgem's approach of relying solely on ILGs was not wrong. However, the supposed weaknesses of relying on both ILGs and AAA corporate bonds offered by Ofgem has already been explored by the CMA at PR19 and found to be minor and/or not insurmountable. Whereas the CMA was clear that sole reliance on ILGs would lead to an underestimate, a far more material problem in a regulatory context when setting a key parameter of CAPM.

662. Ofgem now has the opportunity to reappraise afresh the entirety of evidence on this question. Ofgem should reconsider its position and set RFR in line with the CMA's clearly evidenced and, in our view, manifestly superior alternative.

663. Ofgem's model, through which it intends to implement indexation, should be updated to also rely on AAA corporate bond yields, in line with the CMA's recommendation. Notwithstanding this observation, the CMA's model appears to otherwise function as intended.

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

664. In principle we are not against updating the methodology in response to relevant and up-to-date market evidence. However, in the case of the 2030 RPI reform decision referred to by Ofgem, we note that there is still a significant level of uncertainty:

a. The trustees of the BT Pension Scheme, Ford Pension Schemes and Marks and Spencer Pension Scheme have sought to judicially review the proposals to change the basis on which RPI is set beyond 2030.

b. Current market data on break-even inflation does not indicate a drop in expectations on RPI inflation as of 2030. The chart below is the forward break-even RPI inflation rate taken from Bank of England as of 19-08-2022.

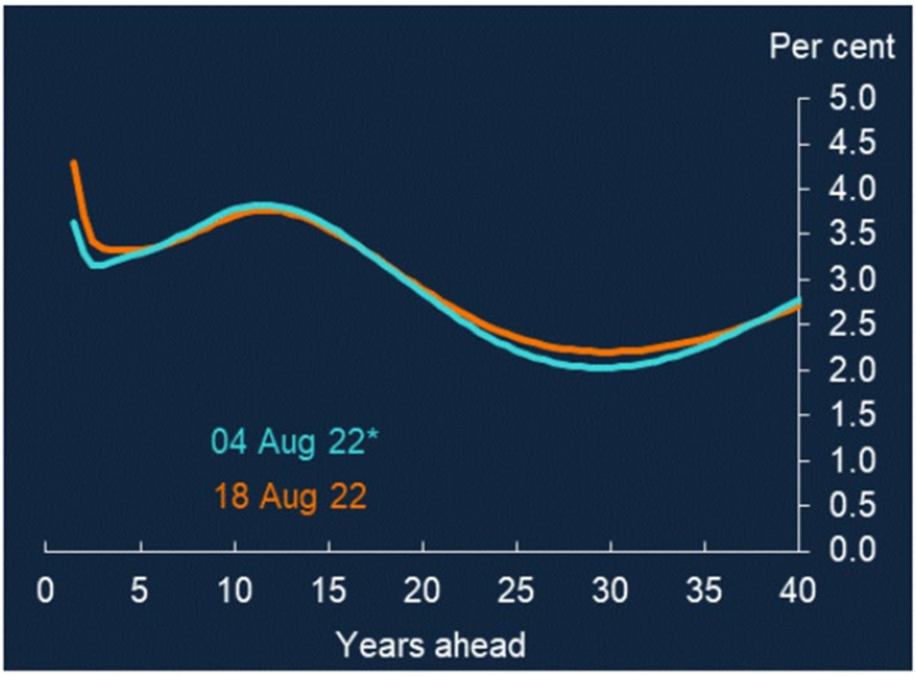

Figure 21. Bank of England, UK instantaneous implied inflation forward curve (gilts), graph extracted on 19-08-2022

665. These curves clearly show that between year 5 and year 10 ahead (straddling the period when in principle RPI should decrease to match CPI), the forward inflation is increasing. This fails to provide evidence that the market has priced in a substantial drop of the RPI in 2030 (in 8 years' time) due to the reform referred to by Ofgem.

666. Since it is not the yet clear whether RPI will indeed be equal to CPI starting from 2030, it is presently not possible to determine whether it is more correct for the RPI-CPIH inflation wedge in the WACC allowance model to be based on a single year or 20-year geometric average. This is because it is not clear which approach would more accurately reflect the inflation assumption priced into the nominal bonds.

667. Notwithstanding this, we consider that using the OBR long-term forecast (year 5) might remain the preferred option, as it seems less likely to embody a clearly wrong assumption, since one does not need to assume 0% wedge for a substantial number of years, as is the case for the 20-year geometric average option.

668. We note that if the 2030 reform is indeed to go ahead, then we would expect OBR to reflect this in its year 5 forecast at the right time. For instance, we would expect OBR to set its year 5 forecast of RPI-CPI wedge to be to exactly 0 starting from 2025/26 onwards. Therefore, if taken as an average over the entire period of ED2, Ofgem's current option (a) may not produce a number much higher than the alternative 20-year geometric average option. The only difference is that the OBR would have a better view of the outcome of the 2030 reform closer to time and can be expected to provide its year 5 forecast on an appropriate basis, whereas the 20-year geometric approach would already assume a 0% wedge for all the years beyond 2030 even in its first year of application of ED2 (i.e. 2023/24).

669. For the above reasons, we prefer Ofgem's option (a) as this approach is less prone to embody the wrong assumptions in calculations, given that the future of RPI is currently not settled. No matter what option Ofgem ultimately chooses, it must have regard to the evolution of the relevant legal proceedings and market evidence, rather than relying on an assumption-driven approach which could cause errors in the estimation.

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

670. We agree with the main approach of considering the historical long-run average of market returns as an indicator of future return expectations, and would not suggest that there is any new evidence in terms of appropriate overall methodology. However, there is new evidence with regards to the specific calculation of historical returns in so far as how these returns should be adjusted for inflation.

671. In order to use historical returns data from the DMS Yearbook in order to inform a real WACC estimate, as Ofgem has, these returns must be converted into real terms. We note that there was significant debate around the appropriate interpretation of real historical returns during the RIIO-2 transmission and gas distribution consultation process, and the ONS has now published a new historical series for the CPI. We address the implications of this in more detail below.

672. Either the RPI or CPI measure can be used in combination with the consumption expenditure deflator to cover the DMS period which covers from 1900 to the current year. Using the CPI measure however, which was only introduced in 1997, required the use of a back-cast model to ensure coverage between 1947 and 1997 (the years when RPI was previously the national statistic). In May 2022, the ONS published a new historical series of data for both CPI and CPIH. Using this new historical data, rather than the previous back-cast model, changes the level of inflation over the period 1900-2021. Analysis by Oxera shows that the new series reduces CPIH inflation over the period by 0.24%, and the CPIH-real TMR range should therefore be adjusted upwards by around 0.25%, giving a new range of 6.5% to 7.0%, with a mid-point of 6.75%.

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

673. Relying on outturn averages is both more objective and also contributes to regulatory stability which is a key principle in the cost of capital estimation. Ensuring a degree of consistency across price controls through using a consistent and objective measure such as outturn returns for TMR, limits the exposure of investors to regulatory risk and keeps the cost of financing relatively lower. This brings benefits to both investors and consumers.

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

674. As outlined in response to question 4 of this section, whilst we agree with the general overall approach to setting the TMR, given the recent developments with regards to the ONS's

publication of the new historical inflation series, even under Ofgem's own method the range used for RIIO-G2&T2 should now sit at 6.5% to 7.0% with a mid-point of 6.75%. For the reasons set out in Oxera's report for the ENA, errors in Ofgem's method of determining TMR mean that TMR should be higher still.

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

675. DNOs have a higher level of systematic risk than the GD&T companies during their respective RIIO-2 periods.

676. Whilst we acknowledge that it could be argued that decarbonisation introduces greater stranding risks for the gas networks during the RIIO-2 period, the flip side of falling gas demand is that decarbonisation is and will create significant challenges for electricity networks, as they rise to the challenge of meeting increasing demand and integrating low carbon technologies into their network.

677. As a result, electricity networks are facing a period of very significant investment and material innovation, that brings with it heightened execution, delivery and operational risks. The critical role that DNOs will play in the energy transition will also bring with it heightened political scrutiny and risks that should be accounted for somewhere.

678. NPg's business plan, for example, set out the need to invest £1.1bn in asset health related to decarbonisation and an additional £516m in network capacity creation, supporting programmes that will transform its network capability. NPg's view is that for now the risks created by decarbonisation are already current and material for DNOs, whereas for gas networks future stranding is less pressing and indeed may be dealt with comprehensively through already existing regulatory measures (or adaptations of these arrangements) and/or the opportunity to repurpose gas networks to carry zero carbon gases.

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

679. We think a qualitative risk comparison between the DNO and other regulated energy networks is a useful exercise. As there are no pure electricity distribution companies in GB which are publicly listed, there is no perfect comparison that can be used to estimate the systematic risk for a company such as NPg, so looking at this qualitatively is also useful. With regards to the specific risks identified in Table 10, we are broadly in agreement with these in terms of the comparison between DNOs and GDNs/transmission sector in general. However, we would suggest that the stranding risk should be relatively low across all sectors given the ability for companies to request changes to depreciation policies at each price control.

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

680. While empirical estimates of beta change all the time, we do not consider it likely that the underlying systematic risk of energy networks has changed materially since the GD&T2 FD was struck. However, for the reasons set out in our response to FQ7, we consider it likely that the

GD&T2 beta estimation method will understate the systematic risk of the electricity distribution sector.

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

681. No, we do not agree with Ofgem's conclusion that the appropriate cost of equity for electricity distributors is "in the lower half of the CAPM range". Ofgem draws this conclusion based on a flawed set of cross-checks that is incomplete. When errors in Ofgem's cross-checks are corrected, when the limited robustness of many is properly accounted for, and when Ofgem's narrow, censored set of cross-checks is appropriately supplemented, then there may be valid evidence to obtain from these. Otherwise, we consider the cross-checks provide no evidence to suggest a lower allowed equity return is appropriate. Indeed, if anything a higher estimate may be more appropriate.

682. Our response to FQ11 sets out some of the limitations associated with the MAR and OFTO evidence which explain why it is wrong to conclude that equity returns are "in all likelihood lower than 4.75%" based on MAR, or that equity returns could be feasibly around 3.1% based on the OFTO evidence.

683. With regards to the investment managers' forecasts, we note that in response to the GD&T DD, we highlighted that Ofgem had disregarded the Schroders 30-year horizon forecast, even though it had recognised that "a 10-year horizon may be shorter than might otherwise be ideal for RIIO-2 purposes". We continue to advocate for longer forecast horizons to be included in the cross-check evidence and would therefore question the conclusion Ofgem makes regarding investment managers' forecasts pointing towards a cost of equity that is lower than Ofgem's CAPM calculations.

684. Our response to FQ13 outlines some additional cross-checks that Ofgem should add to its evidence base, and indeed give prominence to, if it wishes to rely on cross-checks in its Final Determination.

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

685. Whilst we recognise that Ofgem has updated its MAR estimates, we are still of the view that inferences made from MAR estimates provide an unreliable cross-check on CAPM evidence as there is inevitably a wide range for the inferred cost of equity that results from any analysis of MARs, owing to the high degree of uncertainty around what may drive any premium to value. This makes MARs, at best, a relatively loose cross-check.

686. Moreover, there are conceptual challenges in their use. The main shortfall with relying on MAR estimates is that these capture short-term market fluctuations. Given ED2 is taking place during a period of significant macroeconomic uncertainty, with unprecedented rises in inflation and consistent interest rate hikes, it is likely that market valuations now may be distorted and ephemeral in nature. If Ofgem uses today's valuations to inform the cost of equity and set lower returns, it risks having to apply an uplift on the allowed return in future price control periods when there is a downturn and current market values are not sustained. In essence Ofgem will

find itself "chasing the market", when it should be focused on setting a long run, stable level of allowed returns, that better reflects the long run cost of capital.

687. Finally, we note that there would only be reason to adjust returns in light of MAR estimates if Ofgem believes that the valuation placed on energy networks is high in relation to the rest of the market. Frontier Economics has undertaken analysis to establish whether the networks' valuation ratios move in line with the rest of the market, and whether the magnitude of the ratios are in line with the rest of the market. If the networks are indeed in line with the market in these respects, then this demonstrates the limitations of relying on MAR as a cross-check and that Ofgem should not adjust overall returns in light of these.

688. Frontier Economics analysed two different valuation ratios: the price to earnings ratio (P/E) and the enterprise value to earnings before interest, tax, depreciation and amortisation ratio (EV/EBITDA). Frontier's analysis showed that, with minor and immaterial exceptions, GB regulated networks do typically move in line with the rest of the market. In addition, they have a lower valuation than the wider FTSE 100 index, indicating that there is no evidence to suggest that the networks are overvalued. As such there is no evidence to suggest that a reduction in overall returns based on MAR would be appropriate. Hence, we would not suggest that Ofgem's updated approach provides any better inferences for the ED2 period.

689. With regards to using offshore transmission ownership (OFTO) investor bids as cross-checks, whilst we agree with Ofgem that these have some relevance in that OFTO bids also relate to electricity network assets, OFTOs are inherently less risky. In our response to the GD&T DD consultation, we highlighted the significant differences between OFTOs and onshore electricity network assets in terms of revenue, operational and business risk areas. These can be summarised as follows:

a. In terms of revenue risk, OFTOs have a view of revenues over 25 years, in comparison to 5 years for the RIIO networks. Additionally, the RIIO networks are at the forefront of the political agenda and have costs and revenues indexed against other sectors. This is not the case for OFTOs which are not visible to the public and are only subject to a single inflation index.

b. The RIIO networks have a significantly different operational undertaking compared with the OFTOs. The RIIO networks have assets which vary in condition and age and require more ongoing maintenance and construction. These networks are also in close proximity to the public which introduces additional safety concerns and complexities when maintaining the network, which is not a consideration for OFTOs.

c. Finally, the business risks are also different, with the RIIO networks experiencing much greater uncertainty around asset growth, as well having an ongoing refinancing programmes. OFTOs face neither of these risks.

690. These differences between the RIIO networks and OFTOs suggest that OFTOs provide limited value in terms of cross-check evidence. Additionally, Ofgem notes that although OFTOs may

have a lower operational risk, given the much higher financial gearing levels of these networks (around 80-90%), they may have greater financial risk. On the contrary, such a high level of financial gearing reiterates the difference in perceived risk level between the RIIO networks and the OFTOs. As noted in our response to the GD&T DD consultation, the use of OFTOs as a cross-check would only be relevant if the additional risk from the high financial leveraging completely offsets the low level of operational risk such that the RIIO networks and OFTOs could be considered to be comparable. Based on the reasons set out above, we do not view the 3.1% cost of equity obtained from this cross-check as relevant to ED2, even using the 60% notional gearing level as Ofgem has.

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

691. As outlined in response to FQ10 and FQ11, we consider that there are serious limitations with Ofgem's chosen cross-checks, specifically MAR, OFTOs and investment managers' forecasts. We also consider that there are further cross-checks that Ofgem should include in its set, should it choose to rely on cross-checks in its Final Determination.

692. A further cross-check that Ofgem should consider is the dividend growth model (DGM). This is widely used to estimate the cost of equity and importantly is a forward-looking, market implied estimate, which therefore captures investor expectations. The DGM estimates the cost of equity using the networks' stock prices which are based on the present value of the sum of discounted future dividend payments. This is preferable to the MAR cross-check in that the DGM considers future cash flows and requires fewer assumptions. Analysis undertaken by Frontier Economics reveals that Ofgem's CAPM estimate is too low even when compared to DGM estimates of COE with highly conservative assumptions.

693. An additional cross-check that Ofgem should also consider is long-term profitability. This is on the basis that through setting the cost of equity, Ofgem is effectively setting a profitability allowance for the networks. It is therefore appropriate for Ofgem to consider how actual profitability has evolved, at least for comparable networks. Depending on how outturn profitability has moved can inform whether additional adjustments are needed to the cost of equity estimate obtained through the CAPM methodology. This cross-check could be undertaken by looking at return on common equity for the UK utility sector and wider UK market, as well as looking at this specifically for UK and European utility companies which are most comparable to the ED networks. Such an analysis has been undertaken by Frontier Economics on behalf of the ENA. This analysis finds no evidence to suggest that the energy networks, or the wider utility sector, is overvalued, undermining the argument that it may be appropriate to lower allowed returns to reflect ephemeral market valuation data.

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

694. We agree with Ofgem's conclusion not to apply a specific adjustment to the cost of equity following the range of cost of equity estimates obtained from the cross-check evidence. As Ofgem notes, "no cross-check is perfect", and as outlined in response to FQ10-13, we question

the relevance and robustness of some of the cross-checks. We also consider Ofgem's set of cross-checks incomplete, as it excludes a set of other potential sources of evidence that do not suggest that Ofgem's proposed level of allowed equity returns is too high, but in some cases suggest it may not be high enough. Given this we would not agree that the evidence provided by Ofgem points towards the lower end of the CAPM range.

695. Moreover, if Ofgem chose to essentially overwrite evidence from its CAPM analysis with cross-check evidence this would represent a material departure from long standing regulatory precedent, and would be a highly worrying development for investors, not least given the clear deficiencies in Ofgem's cross-check set. For all of these reasons, Ofgem should not place more weight on its cross-checks.

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

696. We agree with Ofgem's DD to not adjust for expected outperformance when setting baseline allowed returns on equity. We take the view that the outperformance wedge originally proposed in the SSMD was misguided due to a number of reasons.

   a. Firstly, it was unclear during the GD&T determination how the outperformance wedge had been calculated.

   b. Secondly, the wedge reduces incentives for companies to outperform in financial areas, which is to the detriment of consumers. As well as reducing incentives for companies to improve performance, the incentive to invest is also reduced given that the overall rate of return is lowered following the 0.25% reduction in the cost of equity allowance.

697. Furthermore, the views we set out above are strongly supported by the CMA's findings during the RIIO-GD&T2 appeals, where the CMA thoroughly appraised the outperformance wedge and concluded that "GEMA was wrong to introduce the outperformance wedge". The CMA noted a number of intrinsic issues with the outperformance wedge such as:

   a. the need for operational outperformance risk to be addressed in a more targeted way,

   b. the way in which the outperformance wedge differed across licensees,

   c. the effects on performance improvement incentives, and

   d. the potential adverse effect for regulatory certainty.

698. There is simply no way for these fundamental deficiencies with the outperformance wedge to be fixed, and as a result it would be wrong for Ofgem to introduce an outperformance wedge at ED2.

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

699. There is no new evidence to support any downward adjustment to the allowed cost of equity. We note in particular that Ofgem's novel outperformance wedge was subjected to substantial

expert scrutiny as part of the recent RIIO-GD2/T2 appeals. After careful appraisal, the CMA quashed Ofgem's proposed 25 bps deduction, and set out a wide range of reasons why an adjustment of this kind was wrong. We agree entirely with the CMA, and consider that Ofgem would be wrong to introduce a similar deduction to ED2 the same reasons.

700. However, an upwards adjustment to the allowed rate of return is needed, and Ofgem was wrong not to include such an adjustment in its DD. This should be fixed in the FD.

701. Firstly, it is widely acknowledged that the costs associated with under- and over-estimating the cost of capital are asymmetric. Typically, the costs to society of setting the WACC too low are much higher than those related to setting the WACC too high. Selecting a point estimate that is too high generally results in marginally higher bills for consumers, where as a WACC that is too low can result in significant under-investment in the sector, and ultimately possible service disruption. As a result, some degree of aiming up above a central estimate of allowed returns can be shown to be the societally optimal policy.

702. Secondly, this issue has been widely considered in academic literature. Key papers, such as those by Wright, Mason and Miles (2003)[16] and Dobbs (2011)[17] demonstrate that it is optimal to aim up in cases where demand is inelastic, the societal loss of non-operation is high, and where the cost of capital applies to new and sunk investments. These conditions particularly apply to energy networks where non-operation is highly disruptive, demand is relatively unresponsive to changes in price and there is a large asset base varying in age.

703. The CMA supported this in its PR19 findings, noting a number of reasons for aiming up on the cost of equity related to investment, asymmetry and uncertainty. It also argued that setting the WACC too low would create uncertainty around future returns which could result in investors withdrawing capital from the sector and discourage networks from identifying capex projects.

704. With regards to asymmetry and uncertainty, firstly the CMA highlighted concerns that where a regime has some asymmetric incentives, choosing a mid-point of the cost of equity/WACC range rather than aiming up, could result in returns below the actual cost of capital. Secondly, the CMA noted that there was considerable uncertainty in estimating the cost of equity and hence this creates greater risk that a point estimate is selected which is either too high or too low.

705. In addition to this, there is a wealth of regulatory precedent which supports aiming up either on the cost of equity point estimate specifically, or on the overall WACC point estimate. In terms of Ofgem price control for example, the RIIO-1 determinations all included some element of aiming up on the cost of equity range, whilst the TPCR4 price control prior to this also included aiming up on the overall WACC. This practice is also not unique to Ofgem; aiming up has been widely used across GB regulators, with the CMA including this for the Bristol Water (2015), NIE

[16] Wright, Mason and Miles, 2003, A study into certain aspects of the cost of capital for regulated utilities in the UK.

[17] Dobbs, 2011, Modelling welfare loss asymmetries arising from uncertainty in the regulatory cost of finance.

(2014), Stansted (2008), Gatwick (2007) and Heathrow (2007)[18] determinations, whilst Ofwat has aimed up on the cost of equity in all of its determinations since PR09.

706. In respect of the CMA's finding that asymmetry in the overall price control calibration is a relevant consideration when considering whether to aim up, Ofgem should consider carefully Oxera's work on skew in the ED2 DD, as set out in an expert report prepared for the ENA. The report identifies a wide range of areas where the calibration of the price control in the DD leads to DNOs facing asymmetric downside risk, i.e. more probability of negative outcomes than positive. Oxera notes that the best way to address such risk is at source, by getting the calibration right. An alternative method if skew is not addressed at source would be to aim up.

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

707. Ofgem should not adjust its approach to allowed returns, nor should it change its approach to indexing RAV, as a consequence of outturn inflation.

708. The existing regulatory structure of indexing RAV to a headline measure of inflation was put in place when the UK regulatory framework for energy networks was created and has now been in place for more than 30 years. This construct has the effect of ensuring that the value of the capital invested in energy network (i.e. the RAV) will always be worth the same in real terms as it was, regardless of outturn inflation. The network neither gains nor loses regardless of what happens to inflation, it is simply made whole. A reasonable real return is then paid on RAV, meaning that investors overall are compensated once and only once for inflation.

709. Around this regulatory structure, network owners then choose to put in place the financial structure that is optimal given their preferences, including determining their overall exposure to inflation risk. By issuing more index-linked debt, the owner can closely match their financing costs with the inflation hedge offered by RAV indexation. By issuing more fixed coupon debt, the owner can create an inverse exposure to inflation. The owner's position relative to inflation can also be modified using derivatives (e.g. inflation swaps). Viewed in this way, the financing structure of the company is simply a way of allocating the headline reasonable real return between equity and debt investors, consistent with the overall inflation exposure of each investor in the company.

710. If a network owner were to issue only index-linked debt, then the overall split of allowed returns between equity and debt would be essentially invariant to inflation. If a network owner issues index-linked and fixed coupon debt in line with the sector average (and hence with the notional company), then the split of the overall reasonable return between debt and equity will likely match closely that found in Ofgem's notional company. If a network owner chooses to issue

[18] Note that Heathrow and Gatwick's 2013 determinations by the CAA also included aiming up on the cost of equity point estimate.

more fixed coupon debt, then the split of the overall reasonable return between debt and equity investors will vary more with inflation. But again, this is simply an allocation question, decided by capital market entities entering into financing contracts.

711. Hitherto, Ofgem could not have been clearer that, subject to adhering to licence conditions, the decision on how to finance a network was a matter for the investor and its management team. Again, this is a long-standing regulatory position.

712. If Ofgem were to make changes now, this would contradict the companies' legitimately-held expectations about the risks they were bearing at the time they made long-lasting decisions about their debt structure. All investors would then wish to modify their financial structure to return to their chosen overall exposure on inflation and this would impose significant costs, without anything like sufficient notice.

713. Investors would also regard steps to change now how the regime treats inflation, at a point when inflation is high, as highly opportunistic. Inflation during the majority of RIIO-1 has been lower than expected, and would have led to any equity holders invested in companies with an inverse inflation exposure achieving lower outturn returns as a consequence. At no point did Ofgem seek to redress this. Throughout RIIO-1 the position that each network chose to take in respect of inflation has been treated as a matter for the company.

714. Lastly, there seems to us no way to make any change that will not be similar in effect to changing how RAV is indexed. Such a change would be material and profound, modifying arrangements that have been in place for more than three decades. And any such change would arrive without any prior signalling, at the very end of a regulatory process that has been running for several years, with almost no proper consultation and, moreover, no proper evidence that the phenomenon Ofgem has identified is a problem at all. The inflation arrangements offered to investors are for us – and we imagine most investors – a clear red line.

715. For all these reasons, if Ofgem were to act along the lines signalled it would be highly disturbing for investor confidence and would, as a consequence, be harmful for consumers and the sector. It would be wrong for Ofgem to make a change in this direction.

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

716. As outlined in response to FQ16, we believe that no adjustment should be made to Ofgem's approach to allowed returns.

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

717. Ofgem is wrong to think that it currently faces a problem with allowed returns that needs fixing. This is not the case.

718. As we explained in our answer to FQ16, the overall effect of Ofgem's regulatory arrangements (indexing RAV and allowing a real return) is to ensure at all times that investors as a whole are

compensated for the overall risk profile of the business in real terms and for inflation (once and only once).

719. The allocation of this overall reasonable return as between equity and debt investors will then be determined by the type of debt products issued. But this is a question only of allocation, not of overall quantum. And Ofgem has argued countless times in the past, that the choice of how to finance each network is a matter for investors.

720. Given this, Ofgem is wrong to believe that steps need to be taken to somehow control ex post returns. The reasonableness of overall returns is assured by the regulatory construct, and the allocation of those returns amongst investors is a matter for the networks.

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

721. We agree with the general principles of Ofgem's financeability testing; i.e assessing the notional company against a range of credit metrics that reflect the general approach undertaken by the credit rating agencies. However, there are some flaws in the approach Ofgem has taken for ED2 related to the assumptions applied in the assessment.

722. There are three key issues that Ofgem needs to address: the impact on capitalisation rates of Ofgem's mis-allocation of totex allowances to cost categories (as set out in our answer to Q111), the artificially low levels of headline totex used in the analysis and the limited period over which the analysis is conducted.

a. Firstly, Ofgem has used DNOs' submitted planning scenarios as he basis for allocating totex allowances across cost categories. The result is a mis-allocation of our efficient costs that shifts c.£150m of our allowances out of cost categories where NPg is demonstrably efficient into the 'variant' secondary reinforcement baseline. Ofgem uses then calculates DNO capitalisation rates by taking the natural capitalisation rates (opex/capex split) submitted by each DNO across cost categories, and weighting these together using submitted cost proportions. The result is that NPgN's capitalisation rate is c.2 percentage points lower than it should be, and NPgY's is c.5 percentage points lower compared to correctly allocated totex based on the disaggregated model cost proportions. Ofgem must correct DNOs' capitalisation rates in line with the adjustment required to the allocation of allowances and re-run the credit metrics tests.

b. In setting the DD, Ofgem has set baseline totex allowances to align to a low decarbonisation pathway, System Transformation. For NPg this equates to totex that is c.11% higher than ED1 levels overall (including variant and non-variant allowances), but c.30% lower than the increase that would be needed to find the CCC's wide Spread Engagement pathway. Setting totex at such low levels flatters the reported credit metrics shown and fails to capture the impact of higher, plausible decarbonisation scenarios or the impact of Access SCR that could materially increase the level of investment required in the period. Adopting a higher and more realistic view of totex , whether funded through ex ante allowances or uncertainty mechanisms, results in credit metrics that stress the notional company. Ofgem should show the full effect of investment requirements in the period on credit metrics.

c. Finally, the analysis performed by Ofgem is limited to the 2023-28 period and therefore does not recognise the strain to credit metrics that will occur in the following price control periods due to the impact of moving to a 45-year asset life on RAV growth and the longer-term impact of the net zero investment requirements. This is short-sighted and Ofgem should broaden its view as well as revisiting its longer term position on the 45-year regulatory depreciation period (see answer to question FQ29).

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

723. Ofgem has failed to properly stress test company financeability in the DD. The tests applied are very limited, only modelling the impact of increasing totex to c.20% vs. ED1 levels for NPg (vs. c.11% in baseline allowances) and RORE being 200 bps lower.

724. Applying a broader range of stress tests including higher totex growth (i.e. up to the uncertainty mechanism cap or beyond) stresses key metrics, namely AICR and FFO/net debt to sub-Baa levels.

725. Ofgem should model and present the broader stress test scenarios, including:

a. The impact of plausible accelerated decarbonisations scenarios and potential impact of Access SCR on credit metrics.

   i) Ofgem's totex stress test in the DD does not even consider totex levels rising as high as its own uncertainty mechanism cap (i.e. c.30% above ED1 levels).

   ii) NPg's plan submission showed totex levels could rise as high as 50% above ED1 levels considering the impact of Access SCR.

b. The impact of spikes in interest rates during the RIIO-ED2 period, in particular further increases in interest rates than those currently experienced in 2022.

   i) Given the recent economic conditions, and ongoing increases in risk free rates, it is clear that there will be ongoing volatility during the next five-year period. Interest rate volatility will be occurring at the same time that the sector will be seeking debt funding to fund RAV increases due to the increasing levels of totex combined with the impact of the transition to a 45-year asset life.

c. Volatile movements in inflation (CPIH) during the RIIO-ED2 period.

   i) Ofgem should stress test the impact of volatile movements in CPIH from generationally high levels and a potential for a significant correction to low or negative rates.

d. Different levels of index-linked debt that reflect the funding across the sector and the availability of index-linked debt during RIIO-ED2.

i) Ofgem's assumption that companies will have 25% of index-linked debt overstates the amount of index-linked debt in the debt profile across the sector. There is likely to be downward pressure on the quantum of index-linked debt issuances in a high-inflation environment.

726. Ofgem has limited its testing to the ED2 period however the decisions made at this price control will have longer-term consequences and are likely to stress credit metrics in the 2030s. As set out in the answer to FQ20 Ofgem should broaden its period of assessment to regulatory periods beyond ED2 to capture the financeability impact of the transition to a 45-year asset life and showing the significant consequences from increasing RAV (and customer bills).

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

727. We have no material concerns with the requirement.

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

728. We agree that these should be variable to take account of what has actually happened.

FQ23: Do you agree with the proposed additional protections? In particular:

729. We do not support the "additional protections", which:

a. are a "regulatory solution without a problem to solve" based on Ofgem's analysis of taxes paid versus allowances for the T2 and GD2 DD (which stated that 'on the whole, allowances were broadly in line with payments made to HMRC, over the course of RIIO-1');

b. will remove or reduce the incentive for licensees to identify efficient and legal approaches to managing their tax bills;

c. will add to administrative burdens for licensees and Ofgem, including the costs of the "independent examiner", and therefore the costs borne by energy consumers; and

d. could be triggered by relatively minor tax timing differences.

730. If Ofgem does implement the additional protections, it should:

a. apply these once per period, in a close out review;

b. use a cumulative materiality threshold, based on the full period's worth of annual values under the current tax trigger; and

c. apply the sharing factor to any clawback, so that licensees still have an incentive to manage their tax bills to the benefit of energy consumers.

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

731. We agree that a materiality threshold is required, but do not support a reconciliation that is assessed annually against an annual RIIO-1 deadband:

a. This could result in a significant additional regulatory burden, both for Ofgem and the companies.

b. With a low annual threshold, companies could easily trigger the review due to factors that might offset each other from year to year.

c. Those licensees with tax years that do not align to the regulatory year are likely to be exposed to additional risk that a review could be triggered due to relatively minor tax mismatches.

d. A close out assessment tax review would be appropriate, after tax returns from the RIIO-2 price control period have been finalised, to minimise the regulatory burden. A materiality threshold based on five years-worth of the current deadband would ensure proportionality in the assessment. The single year threshold would be too low to use as part of a five-yearly tax review, since relatively minor tax timing differences would be too likely to trigger the review.

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

732. As described in our response to FQ24, we do not think that the deadband used in RIIO-ED1 is an appropriate threshold to use annually, but we would support the use of the cumulative value of the deadband over the price control period.

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

733. We support the retention of the tax trigger for changes in corporation tax rates, including its application without a threshold.

734. We support the proposed glidepath for the tax clawback mechanism, in relation to the reduction in notional gearing.

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

735. Yes, we do, with one caveat.

736. We have a concern with the proposal for the adjustment rate that would apply once company performance moves outside +/-400bps. Ofgem’s proposal to set this adjustment rate at 90% will lead to financial incentives on all aspects of operational performance being reduced to just one tenth of their standard strength. This comes perilously close to imposing a ‘hard cap and floor regime’, something that Ofgem had previously ruled out owing to the distortions it would create.

737. We do note that this 90% adjustment factor is unlikely to be applied to a DNO in practice during ED2, given where the threshold for its application has been set.

738. It will, however, be important for Ofgem to keep the need for strong incentives at the forefront of its thinking in future. It would be very harmful to the interests of consumers if such an extreme adjustment factor were to be applied to a tighter threshold in future.

739. Having taken the trouble to implement a RAM, as we argued in our response to the SSMC, Ofgem should then be willing to set strong incentives across the rest of the settlement, given how well these have served energy consumers through the lower costs and better performance they have encouraged.

740. The ED2 price control has to create an environment where DNOs are incentivised to make the investments that are required to facilitate the net zero transition as efficiently as possible. This will lower costs to consumers in this price control and provide critical learnings to support the development of ED3 and beyond. Yet Ofgem is largely proposing to replicate many aspects of its T2 and GD2 methodology. That methodology is not appropriate for electricity distribution.

741. Compared to ED1, Ofgem is proposing substantial changes to the regulatory framework, including far more extensive use of uncertainty mechanisms, ex post assessment, claw-backs and a general reduction in the rewards that are available where a company outperforms. The effect of each of these changes is to reduce the incentive for companies to seek more efficient ways of running their business. The harm this will do to consumers will be incremental. It will build slowly and over a long period of time. But it will be costly.

742. In any scenario, we would argue that customers are better served by a price control that makes more use of ex ante allowances and well calibrated incentives. But this is particularly important at ED2. Ofgem (and Government) expects the DNOs to begin to provide the platform for societal decarbonisation, to transition into the role of DSO and to seek out innovative solutions other than reinforcement to solve constraints on the network. In this scenario, the cost to customers of diluting incentives by increasing the scope for subjective, ex post adjustments and regulatory micromanagement - at the same time as setting too low an allowed return on investment - are very significant.

743. There is still time for Ofgem to change course in key areas, and Ofgem should feel fully able to do so by the presence of a RAM calibrated as Ofgem proposes.

744. Ofgem should set an *ex ante* allowance for secondary Load Related Expenditure. There are compelling reasons to do so as we set out in our answer to Core Q-67. While the risk of windfall gains can be mitigated through appropriate calibration of ex ante allowances, RAMs should provide a further reason for Ofgem to change course.

745. Ofgem should revisit its calibration of key ODIs and set higher rates to provide stronger incentives, in particular for IIS. Again, the benefits of doing so are clear, while any risk is moderated by Ofgem's RAM.

746. Each of these changes would move ED2 closer to core RIIO principles and would drive further efficiency and improved performance than Ofgem's current proposals.

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

747. The PCFM appears to correctly implement the switch from RPI to CPIH as described by Ofgem in paragraph 9.6 of the finance annex. That is, the inflation index is calculated based on monthly RPI inflation up until March 2023, an average of RPI and CPIH inflation in April 2023, and CPIH inflation thereafter.

748. Our view is that this is a sensible approach to implementing the switch from RPI to CPIH, and, as Ofgem states, is consistent with the approach used for GD2 and T2.

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

749. In our response to the SSMC we set out our view that in order to create much needed financial headroom to help fund any major increase in investment for the low carbon transition, Ofgem should:

   a. Set the asset life for business as usual levels of investment at the current average (ca. 25 years); and

   b. Retain flexibility to use the longer 45-year asset life, for any significant additional investment.

750. We took this position based on a careful analysis of the available evidence in three key areas:

   a. in respect of inter-generational fairness, we noted that current customers have not been overpaying under a 20-year regulatory depreciation period, owing to the combination of past depreciation policy and the receipt of a 'privatisation dividend';

   b. we noted that RAV, and network charges, would increase significantly if the 45-year regulatory depreciation period was maintained, in particular given the likely increase in investment in electricity networks, and that these factors would cause future consumers to face unduly large future bills; and

   c. the 45-year asset life policy could strain financeability as electricity distribution heads into the net zero transition, which may increase financing costs and/or limit the capacity of networks to respond to future investment needs.

751. Our proposal for a shorter depreciation lifetime, with the option to use 45 years on a case-by-case basis, would therefore bring clear benefits if adopted.

752. While we remain of the view that a shorter lifetime should be preferred as it would bring benefits to consumers, it seems clear that Ofgem has decided to stick with the policy it set out in its SSMD.

753. Nevertheless, assuming that Ofgem will not take the opportunity to address this issue now, we urge Ofgem to keep this policy under review during RIIO-ED2, and to revisit the evidence again as part of the RIIO-ED3.

754. RAV growth, and hence pressure on bills, is likely to be more rapid than Ofgem's modelling may suggest, owing to the scope for a material, incremental quantum of expenditure to be funded through Uncertainty Mechanisms. The scale of investment in electricity networks is likely to grow in future price controls, not fall.

755. We anticipate that the case for a shorter depreciation lifetime will become ever clearer as time passes. RIIO-ED3 provides another opportunity to solve this issue – it may be the last such opportunity before it becomes impossible to solve and Ofgem becomes locked into long lifetimes, large RAVs and higher bills.

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

756. No, we do not support different capitalisation rates for ex ante allowances and re-openers and volume drivers.

    a. The basis of the current capitalisation rates does not take account of any incremental indirect costs DNOs are likely to incur.

757. We also do not support licensee-specific capitalisation rates. Instead, we support a benchmarked sector average whereby all companies have the same capitalisation rates.

758. We have two reasons for this.

    a. Any differences may reflect nothing more than accounting assumptions: the relatively small differences across licensees in the ED1 settlement are just as likely to have reflected differences in calculations of the capitalisation rate rather than differences in the underlying proportions of long-lived versus short lived expenditure.

    b. A benchmarked approach would further reduce any bias towards network investment solutions: the RIIO approach to regulation imposes a fixed capitalisation rate so that licensees have less reason to favour capital over operating or innovative solutions such as flexibility services, at least in terms of RAV growth. Applying a benchmarked average capitalisation rate would apply this principle to the business planning process, such that a licensee that forecast it would use more of such solutions in its business plan would not receive a lower capitalisation rate.

FQ31: Do you have any evidence that would enable us to improve our estimates of regulatory capitalisation rates?

759. In setting allowances Ofgem has mis-allocated the allowances arising from cost benchmarking process based on the DNOs' submitted costs. We believe this is an error and that the allocation of allowances should be based on the outputs of the disaggregated models. This revised allocation of allowances would give lower capitalisation rates for most DNOs (except ENWL and SSEH and SSES, who submitted the same rate for all expenditure categories). Ofgem should correct the allocation of allowances and consequently the capitalisation rates.

760. It is not clear from the DD why Ofgem is comfortable with such varying levels of capitalisation between DNOs leading to significant differences in companies' revenues. The lowest capitalisation rate is 68% for SSES and SSEH and the highest is 80% for WPD SWEST.

761. Ofgem should also review inconsistent inputs between DNOs. Several DNOs have submitted the same rate for all expenditure categories and rates are otherwise likely to differ between DNOs because of different assumptions used in calculating them.

762. We believe Ofgem should use a fixed capitalisation rate which is simple and well understood as opposed to using information provided from DNOs which is inconsistent.

763. Ofgem has also previously stated that it thinks there are benefits from using fixed capitalisation rates and that using actual capitalisations rates results in "distorting decision making" and unequalised incentives. Given a fixed capitalisation rate was one of Ofgem's major RIIO innovations, we are not sure why Ofgem is now considering reverting to the use of actual capitalisation rates; it would therefore help if Ofgem could set out why it is now considering a change back, in light of its previous reasoning on this topic (which we reproduce below).

764. In DPCR5, we modified our approach to capitalisation, with all companies having a fixed percentage of their total network costs capitalised into the RAV and the rest being expensed in year. This was intended to equalise the incentives on capex and opex and avoid distorting decision making.

765. Going forward we believe that to help equalise incentives we should set a fixed percentage of total expenditure to be capitalised during the price control period. We will set the percentage at the price control review, seeking to strike a fair balance between existing and future consumers in light of the nature of the expenditure expected over the price control period (e.g. drawing on the amount of capex like costs submitted in a company's business plans)[19].

FQ32: Have any views on the use of forecast RAV opening balances for the start of RIIO-ED2, which will be trued-up following RIIO-ED1 closeout?

766. We have no material concerns with this approach.

FQ33: Do you agree that additional corporate governance reporting described (including on executive director remuneration and dividend policies), will help to improve the legitimacy and transparency of a company's performance under the price control? If not, please outline your views in relation to the rationale provided for these additional requirements, including consumer protection.

767. No, we do not support these additional reporting requirements in respect of executive pay or dividend policies.

768. Ofgem should not require licensees to publish details of executive remuneration.

[19] Ofgem, 2010, RIIO handbook, page 109, paragraphs 12.20-21

a. An individual's remuneration is considered to be personal data under the General Data Protection Regulation. In addition, a company is contractually bound to keep personal data confidential.

b. Parliament, the Financial Conduct Authority, the Financial Reporting Council (soon to be the Audit, Reporting and Governance Authority) and any exchange a company's securities are listed on set the rules in respect of good corporate governance and the disclosure of directors' remuneration. These rules invariably recognise that the requirement to disclose information should vary depending on the nature of a company's ownership structure.

c. Enhancements to the corporate governance regime are already being led by the Government. In May 2022, the Department for Business, Energy and Industrial Strategy published 'Restoring trust in audit and corporate governance, the Government response to the consultation on strengthening the UK's audit, corporate reporting and corporate governance systems'. Changes (which will include additional scrutiny for Public Interest Entities) will be effected through primary and secondary legislation and amendments to regulatory codes. Supplementary and potentially divergent requirements imposed by Ofgem are therefore unnecessary and unhelpful.

769. Ofgem's argument that publication is required because the licensees are natural monopolies and regulated companies doesn't stand scrutiny:

a. To the extent that the licensees need to be treated differently to any other company, Parliament has already set out additional reporting requirements (e.g., section 42C of the Electricity Act 1989).

b. The licence itself also prescribes additional reporting requirements including in the form of the regulatory accounts (SLC 44).

c. Ofgem has put in place a price control that ensures licensees are incentivised to keep all costs as low as they can; this includes indirect costs.

d. Directors' remuneration is a tiny fraction of a licensee's cost base. Ofgem should not be micro-managing certain cost sub-categories; within the envelope of its allowed costs, it is for the licensee to determine how to meet its obligations as efficiently as possible.

770. Ofgem should also consider the risk that this will place upwards pressure on the pay of executives at companies that have managed their executive pay most efficiently, by revealing pay rates across the market. Executive remuneration will likely be unnecessarily ratcheted upwards, which is the antithesis of the objective of good governance.

771. As suggested previously, Ofgem could consider whether or not gathering director remuneration information at an aggregate level for each licensee would be more appropriate. This may just involve a cross-reference to the company accounts, which could be accompanied by a high-level explanation as to how remuneration is set.

772. The requirement for additional reporting on dividend policies is also unnecessary. Company law and the ringfence provisions in the licence already provide adequate protection to stakeholders that licensees cannot pay dividends when they shouldn't.

773. By creating additional layers of reporting obligations Ofgem will simply increase the administrative and associated financial burden that each company faces. This cannot provide any benefit to consumers.

FQ34: What are your views on the proposed consolidation of the revenue RRP and PCFM, or applying a fully dynamic concept of allowed revenue?

774. We are comfortable with the proposed approach which will bring the benefits of greater transparency and simplicity when calculating Allowed Revenue and publishing Network Charges to recover it.

775. Consideration should be given to further simplification and size of the consolidated model to ensure that users can easily understand, operate and audit the model.

FQ35: What are your views on allowing licensees to self-publish the PCFM with their charging statements, rather than relying on an Ofgem publication or direction to determine allowed revenue?

776. We are comfortable with the proposed approach, whilst recognising that Ofgem will still need to finalise and publish the model to be used.

777. The licence should be the primary source of the calculations (i.e. the algebra) and defined terms used in the model, rather than the Price Control Financial Handbook (the 'PCFH'). Ofgem should also make the current version of the licence easily accessible to users, for example on its website, because the licence ultimately sets out the DNOs' obligations.

778. We note from engagement with Ofgem via the RIIO-ED2 licence drafting working group that it is Ofgem's intention that a provision in the PCFH will require a DNO to provide the Authority with the model it intends on publishing with its charging statement – along with a commentary describing any changes since the model was published previously– not less than 14 days prior to publishing its Network Charges.

779. In practical terms this is problematic for three reasons:

a. DNOs are obligated to publish Network Charges before 1 January each year but generally aim to do so before Christmas and, therefore, the actual publication date can vary;

b. for various reasons, some of which are often outside of a DNO's control, for example where the DNO is reliant on external sources of information, the DNO may have to vary its calculation of Allowed Revenue within 14 days prior to publication of Network Charges to ensure compliance with its forecasting obligation regarding Allowed Revenue; and

c. it will introduce additional time constraints into the process, given that a DNO does not currently have to explain the movement in Allowed Revenue between publications of Network Charges, and it is not clear as to how any intervention Ofgem may choose to make during the 14 day period up to a DNO publishing the Network Charges would impact on the timescales.

780. It is our understanding from the licence drafting working group that, if a DNO were to publish the model not less than 14 days prior to publishing its Network Charges and then have to vary its calculation of Allowed Revenue, that scenario would not trigger the requirement to publish the revised model not less than 14 days prior to publishing its Network Charges. That position should be reflected in the drafting of the PCFH. If that is not done and the drafting of the PCFH remains as it is currently, that timing issue may mean that changes to the amount Network Charges are set to recover cannot be made and, therefore, may conflict with the DNO's forecasting obligation regarding Allowed Revenue.

781. This requirement should also be considered in the context of a DNO being required to republish Network Charges other than by 1 January for reasons outside of its control.[20]

FQ36: What are your views on having a best endeavours obligation for charge setting: "The licensee must, when setting Network Charges, use its best endeavours to ensure that Recovered Revenue equals Allowed Revenue"?

782. We disagree with Ofgem's proposal to require DNOs to deploy best endeavours when setting Network Charges. Following a discussion at the licence drafting working group on 6 December 2021, the Energy Networks Association (ENA) wrote to Ofgem on 16 December 2021 raising concerns on behalf of all of the DNOs that Ofgem had inappropriately increased the level of obligation on DNOs from "reasonable endeavours" (the standard applied in RIIO-ED1) to "best endeavours". The DNOs then provided a joint follow-up note on 30 March 2022 providing some examples of activities that the change to best endeavours for setting network charges might oblige DNOs to undertake that seem disproportionate or that may cut across other policy objectives. Ofgem has not addressed the issues raised in a subsequent licence drafting working group and we remain of the view that those issues are valid and that an obligation to use "reasonable endeavours" continues to be most appropriate, as opposed to an unqualified best endeavours requirement.

783. Ofgem made a conscious decision to require DNOs to use reasonable endeavours when setting network charges for RIIO-ED1 and has not adequately justified its proposal to impose a more onerous obligation. The arguments Ofgem has put forward are not sufficient, individually or collectively, to justify the proposed change. Furthermore, Ofgem has failed to recognise that it would be inconsistent to increase this obligation at the same time as making other changes to the price control package such as removing the two-year lag that applies to many aspects of the price control flowing through to Allowed Revenues.

[20] For example, in January 2022 DNOs republished Network Charges for the 2022/23 regulatory year to recover their share of c.£1.8bn costs associated with Ofgem's Supplier of Last Resort ('SoLR') mechanism, and where the amount to be recovered in that regulatory year was not finalised until 28 January 2022 but included a requirement (set by Ofgem) to publish revised Network Charges by 31 January 2022.

784. Ofgem's argument that a change is required to reflect "the most fundamental obligation in the price control" fails to recognise:

a. the increasing costs to be funded by customers without additional benefit; and

b. the safeguards that are already incorporated into the price control to protect customers from any deviation between Allowed Revenue and Recovered Revenue.

785. Any efforts to further improve the accuracy of forecasting of network charges will only ever make marginal improvements. The costs incurred to do so may be considerable and, in any case, any marginal improvements in accuracy will be dwarfed by the general uncertainty associated with forecasting many material aspects of both Allowed and Recovered Revenue. There are also other existing safeguards in place to protect customers from the adverse effect of network charges being set in a way that does not lead to Recovered Revenue matching Allowed Revenue. These safeguards include under- and over-recovery mechanisms that ensure that customers ultimately pay the appropriate amount and penalty interest calculations that apply to any material deviations between Allowed Revenue and Recovered Revenue. These are far more effective safeguards than Ofgem's proposal to change the level of obligation.

786. The DNOs have provided Ofgem with specific examples of activities that could be required under a best endeavours obligation and demonstrate the additional costs that would be incurred in chasing very marginal improvements in accuracy of Network Charges but Ofgem has not answered those examples and has failed to provide examples of its own that justify increasing the obligation.

787. Ofgem partly justifies its approach by reference to a desire for alignment between sectors. The DD states that there "should be a reason for inconsistency between sectors" and the DNOs believe that there are strong reasons to justify a different approach for electricity distribution. The process for setting network charges in electricity distribution is quite different to that in other sectors, such as gas distribution where the requirement is to provide at most three months' notice. Ofgem considered these differences in reaching its decision in respect of RIIO-ED1 and concluded that it was appropriate to set the level of obligation at a lower standard for DNOs than for gas distributors or transmission operators. The arguments for there to be a different approach to other sectors have strengthened during RIIO-ED1, in particular with the introduction of the requirement to give 15 months' notice of changes to Network Charges and the additional forecasting complexities and difficulties associated with that requirement. We are particularly concerned about the interaction with the obligation to provide 15 months' notice of a change in network charges and do not consider that either the interaction with the 'dynamic' concept of Allowed Revenue or DNO self-publication of the model justifies increasing the level of the obligation to best endeavours in this context. In addition, Ofgem proposes to set DNOs the more accurate target of "equal to" rather than the target of "does not exceed" that is applied to gas distributors or transmission operators. While we agree that this different target more accurately reflects the intent of the price control, it is a different standard and requires greater accuracy to achieve. Continuation of a different performance standard is,

therefore, justified and a simple alignment between sectors cannot be used to justify the change.

788. We believe that increasing the level of the obligation to best endeavours will increase the likelihood that the DNOs will have to request a derogation from the notice period. For example, DNOs will need to forecast Allowed Revenue for RIIO-ED3 – effective from 1 April 2028 – using best endeavours at a point in the RIIO-ED3 price control process when there will be no visibility of the potential outcome.

789. If Ofgem does decide to increase the level of the obligation to best endeavours:

a. we agree that it is better to seek to ensure that Recovered Revenue 'equals' rather than 'does not exceed' Allowed Revenue;

b. we would question the need to provide Ofgem with the model 14 days prior to publishing Network Charges together with an explanation as to what has changed for the reasons noted above; and

c. Ofgem must set out guidance specifying the actions that DNOs should undertake to meet the standard, which should either be in the licence itself or have the appropriate power to qualify the obligation in the licence.

FQ37: What are your views on applying a single time value of money to all prior year adjustments, based on nominal WACC?

790. We agree with the use of the nominal WACC via a single time value of money adjustment. This simplifies licence drafting and, therefore, the calculation of Allowed Revenue.

FQ38: What are your views on our proposed approach to using forecasts within RIIO-ED2?

791. In general, we are comfortable with the proposed approach to using forecasts. However:

a. we agree with Ofgem that the approach risks making Network Charges less predictable and, as this risk will be taken by DNOs and ultimately by consumers, it increases the likelihood that the 15 months' notice period of changes to Network Charges may need to be disapplied, especially in the context of an increased level of obligation to best endeavours; and

b. we require further information on the scope of the 'case-by-case guidance' that Ofgem will provide in relation to 'other revenue components' such as pass-through costs etc.

FQ39: What are your views on the proposed charging penalty mechanism?

792. We are comfortable with the proposed 6% penalty threshold and the ability for the Authority to direct a lower penalty rate where a variance is outside of the reasonable control of the DNO.

FQ40: What are your views on the proposed revenue forecasting penalty mechanism?

793. We agree with Ofgem's proposal to limit the Allowed Revenue forecasting penalty to a subset of allowances, principally base revenue. We are also comfortable with the proposed 6% penalty

threshold and the ability for the Authority to direct a lower penalty rate where a variance is outside of the reasonable control of the DNO.

FQ41: What are your views on removing lags from incentives? Consultation question on baselines for ODI incentive rates, caps, and collars

794. Due to the need to provide 15 months' notice of a change in Network Charges, a DNO currently forecasts incentive reward/penalty despite the existing two-year lag.[21] Removing the lag will increase volatility which will be reflected in future Network Charges.

795. Ofgem also proposes to reduce the correction of over/under-recovery from two years to one year in RIIO-ED2. Taking incentive allowances in the 2023/24 regulatory year (based on performance in 2022/23) as an example:

a. In December 2021: the DNO forecasts performance and therefore reward/penalty to be recovered in 2023/24;[22]

b. In December 2022: the DNO forecasts a revised view of performance and reward/penalty associated with the 2023/24 regulatory year which will impact the correction of over/under-recovery for that year in the 2024/25 regulatory year (i.e. for the period in which Network Charges are being published); and

c. In December 2023: the DNO includes the actual performance and reward/penalty associated with the 2023/24 regulatory allowances, which impacts the correction of over/under-recovery for both the 2024/25 and 2025/26 regulatory years (i.e. the knock-on impact of a one-year lag on correction), the latter being the period for which Network Charges are being published.

d. Consequently, the 15 months' notice period will likely result in a two-year lag, unless the forecasts are accurate. Ofgem recognises the impact that the removal of the lag will have on the predictability of Allowed Revenue and we request confirmation as to what Ofgem means by the mitigation "Ofgem makes a considered, deliberate choice about the appropriate notice period for charging", for example whether consideration is being given for reducing the notice period for charges

796. We agree that removal of the lag will promote consistency within the Price Control Financial Model ('PCFM'). However, as noted above, understanding when Network Charges are impacted, and to what extent, is arguably no less clear than in RIIO-ED1.

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[21] For example, when publishing Network Charges for the 2022/23 regulatory year in December 2020, it was only part way through the 2020/21 regulatory year from which performance drives the allowance to be recovered.

[22] As DNOs did not have visibility of the RIIO-ED2 Draft Determination, and due to wider uncertainty, no forecast reward/penalty was included to mitigate against the risk of over-recovery.

FQ42: What is your view on using RoRE as a general baseline for describing ODI caps, rather than base revenue?

797. We have no material concerns with this approach and agree it is likely easier for stakeholders to understand given the varying sizes of each DNO.

FQ43: What is your view on fixing the potential £m 20/21 value of incentives using one number for all years, based on a forecast of RIIO-ED2 at Final Determinations (an approach similar to RIIO-ED1)?

798. We have no material concerns with this approach.

FQ44: What is your view on the method of calibrating incentive caps in RoRE terms, or the overall proposed incentive caps?

799. We have no material concerns with this approach.

FQ45: What are your views on our proposal to remove the Bad Debt terms from the pass-through licence condition?

800. We agree with Ofgem's proposal to remove the Bad Debt pass-through terms and instead adjust the calculation of Recovered Revenue to reflect amounts recovered rather than billed; a DNO will set-off Bad Debt and recover it through the correction of over/under-recovery instead.

801. Such adjustments may materially impact the charging penalty mechanism, but we expect that Ofgem would agree that Bad Debt is outside of the DNO's reasonable control.

802. We anticipate that the legacy pass-through adjustments (a component of the LAR term) will adjust RIIO-ED2 Allowed Revenue for Bad Debt incurred in RIIO-ED1 but Ofgem should clarify what it is referring by a need to estimate such amounts in FD and a subsequent true-up.

803. In line with drafting shared at the July licence drafting working group and as previously communicated to Ofgem, we agree that a pass-through item needs to be retained to allow a DNO to recover bad debt claimed by an IDNO, which the DNO in turn recovers and pays to the IDNO in accordance with standard condition 38C 'Treatment of Valid Bad Debt Claims' ('SLC38C').

804. However, we are concerned that the definition of the BDA term excludes any Valid Bad Debt Claims under SLC38C. Once an IDNO has submitted a Valid Bad Debt Claim, the DNO pays that IDNO the respective amount, thus transferring the debt to the DNO. This means that if a supplier ceases to trade, any amounts attributable to the Valid Bad Debt Claim in Network Charges manifest as Bad Debt for the DNO. It is, therefore, unclear how the DNO would be able to recover the unrecovered element of a Valid Bad Debt Claim, if a supplier ceases to trade.

805. We propose that Ofgem makes the definition of Recovered Revenue (the RR term) algebraic, consistent with other terms, to add further clarity that it is a billed amount less Bad Debt.

806. We included the above suggestions, along with others, in issues logs provided to Ofgem as part of the licence drafting working group. We are keen to understand Ofgem's position on the points raised by the DNOs, including other areas of the licence drafting where transparency is generally inadequate.

FQ46: Should Ofgem allow proposals to re-allocate or re-profile revenue throughout the RIIO-ED2 period and what profiles could be considered in the customers' interest?

807. The DD shows the bill reducing over the period. In order to assist customers at a time when energy bills are high, we could consider profiling revenues so they are flat over the period.

NPg Annex

NPg-Q1: What are your views on the company specific parameters we have proposed for the common outputs that we have set out above?

808. We have provided comprehensive responses to the questions on each output area set out in the Core methodology document.

809. In headline terms:

a. IIS: We believe this represents a reasonable package and we are supportive of the more holistic target setting methodology. It should however be noted that Ofgem's decision can be expected to perpetuate a performance gap that our stakeholders were supportive of closing. Ofgem should acknowledge the impact of climate change on the frequency of exceptional events when setting the collar. See our responses to Core-Q45-49.

b. NARMS: We have fundamental concerns with the proposed approach. We believe that holding targets static with no consideration to the impact of the cost disallowance is flawed. See our response to Core-Q54.

c. Consumer Vulnerability: We agree with the defined performance metrics to be included in the incentive. We do not, however, agree with the targets and associated performance caps and penalty collars for all areas. We believe there are some fundamental areas that need adapting for the incentive to be successful.

d. We agree with the use of NPV for measurement of both fuel poverty and Low Carbon Technology (LCT) services and the values set out. However, as all DNOs have put in assumptive measures around benefits for these largely untested LCT services, we would welcome the opportunity to review and refresh these targets as different service models are delivered and tested giving us stronger verifiable proxies. Our preference would be an annual review and refresh or something in line with the assurance at years 2 and 5 across the DNOs. See our response to Core-Q34.

e. Major Connections: The overall framework of the incentive seems reasonable, however we believe it would be more appropriate to base the financial exposure on the value of each relevant market segment, rather than RORE, as this could lead to penalties that are greater than the total value of the market. See our response to Core-Q40.

NPg-Q2: What are your views on our proposal to reject NPg's bespoke price control deliverable?

810. Please see our response to Core-Q49 and Core-Q106. Ofgem's decision will perpetuate a performance gap that our stakeholders were supportive of closing. If Ofgem changes its approach to IIS target-setting, we would need to reassess whether new targets could feasibly be delivered without specific additional funding and a PCD.

NPg-Q3: What are your views on our proposals for NPg's CVPs?

811. We do not agree with the overall approach.

812. Other than the one-stop app for vulnerable customers, which was included as an independent cost line item, we are being asked to fund accepted CVPs through baseline allowances. Ofgem has applied significant cost disallowances across the plan, while at the same time accepting most of our output commitments, creating insufficient cost allowances to fund outputs.

813. We will need to review and prioritise the costs and delivery for the two unfunded CVPs (voltage optimisation and open insights) alongside other outputs within the baseline cost envelope.

NPg-Q4: What are your views on our proposals for the outcome of Stages 3 and 4 of the BPI for NPg?

814. We have no material comments.

NPg-Q5. What are your views on the level of proposed NIA funding for NPg?

815. Ofgem has only allowed half of the innovation funding we proposed in our plan. This is a mistake, particularly at a time when innovation for decarbonisation and customer vulnerability is essential.

816. Ofgem has chosen to only fund three years of innovation. This will deter DNOs from embarking on more complicated, multi-year projects, even where those may yield greater benefits for customers.

817. Ofgem's funding for innovation should be ambitious and it should cover the full five years of ED2. In addition, Ofgem's new SIF mechanism should be amended to maintain the lighter and faster governance of the current NIA mechanism.