T2 and GD2 draft determinations response

KEY POINTS

- Ofgem must significantly revise its T2 and GD2 draft determinations as the settlements it is proposing would harm the interests of consumers and damage investor confidence.
- Ofgem's approach to setting the cost of equity is wrong and the result is a return well below the marginal cost of equity investment.
  - Ofgem's CAPM estimate appears to be a "goal seek" to match Ofwat's.
  - Ofgem uses flawed and circular cross checks to compound this mistake, lowering its range even further.
  - Ofgem then makes an additional outperformance reduction, which necessarily results in a number below Ofgem's own estimate of the cost of equity.
- Ofgem has set productivity assumptions that are not supported by the evidence it presents.
  - Ofgem ignores the gross output range altogether, despite this better representing the cost base Ofgem is dealing with.
  - Instead, Ofgem cherry picks from the top of a more volatile value added range.
  - And then tops this up on its hunch that regulated utilities are particularly innovative, thanks to their management "having lots of spare time".
  - Past productivity improvements have been driven by network operators taking measured risks and adopting new working practices in response to strong incentives; with much weakened incentives Ofgem cannot assume this will continue.
- Established good practice on setting upper quartile cost benchmarks has been jettisoned. Presumably this is simply to allow Ofgem to set lower benchmarks.
- The move to downwards only pass through of many cost efficiency savings will destroy one of the cornerstones of incentive regulation and raise long term costs to consumers.
- Ofgem's desire to be able to trigger reopeners to reduce allowances at any time and with little process diminishes the certainty investors require.
- Ofgem's plans to lay additional requirements on top of the appeal regime are either unnecessary or ultra vires and proposing them damages investor confidence.
- None of this is in the interests of current and future energy consumers (taken together). It will damage investor sentiment and reduce investor appetite to make investments into Great Britain's energy networks.
- A short-term minimisation agenda will ultimately mean that consumers either need to pay more or do without infrastructure upgrades that they would benefit from.
- Ofgem should instead take a view that balances the need for investment with the need for efficiency – getting each constituent element of its decision right.

Contents

1. Overview: Ofgem must significantly revise its T2 and GD2 draft determinations

1. It is apparent from our review of the T2 and GD2 draft determinations that much change is needed before Ofgem can finalise these price controls. Ofgem needs to re-set many aspects of them.
2. We have been concerned that, as Ofgem has developed its RIIO-2 framework and methodologies, it was painting itself into a corner. Unfortunately, the T2 and GD2 draft determinations crystallise that concern.
3. They will no doubt give Ofgem the improbably low headline figures it seems to crave. But one only has to look a little past the day of the decision to see that these settlements would harm the interests of consumers and damage investor confidence.
4. At each turn the draft determinations replace the incentives that are meant to be a cornerstone of the RIIO regime with uncertainty mechanisms, ex post assessment, claw-backs and a reduction in the rewards that are available where a company finds a more efficient way of running its 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.
5. There are many indications, spread right across the draft determinations, that Ofgem has gerrymandered the evidence to reduce the charges that transmission and gas distribution companies can levy. The allowed return on equity is below its marginal cost. The productivity assumptions are fanciful, particularly in a world of much reduced and capped incentives. And the approach to cost assessment creates unachievable benchmarks. This will also harm consumers, more immediately.
6. This pattern is evident to us as stakeholders outside of the direct process, with no direct ownership interest in any of the affected businesses. But, if we are correct, we expect the businesses involved will have identified many more similar instances.
7. This is not in the interests of current and future energy consumers (taken together), because this regulatory approach will damage investor sentiment and reduce investor appetite to make investments into Great Britain's energy networks. A short-term minimisation agenda will ultimately mean that consumers either need to pay more or do without infrastructure upgrades that they would benefit from. Ofgem should instead take a balanced view across the settlement in order to meet its duties.
8. We set out below the most critical issues as we see them, and how Ofgem needs to solve them.

Ofgem's approach to setting the allowed cost of equity is wrong and the result is a return well below the marginal cost of equity investment

9. In essence, Ofgem has:

a. Ostensibly gerrymandered a range for beta estimates that is much too low;

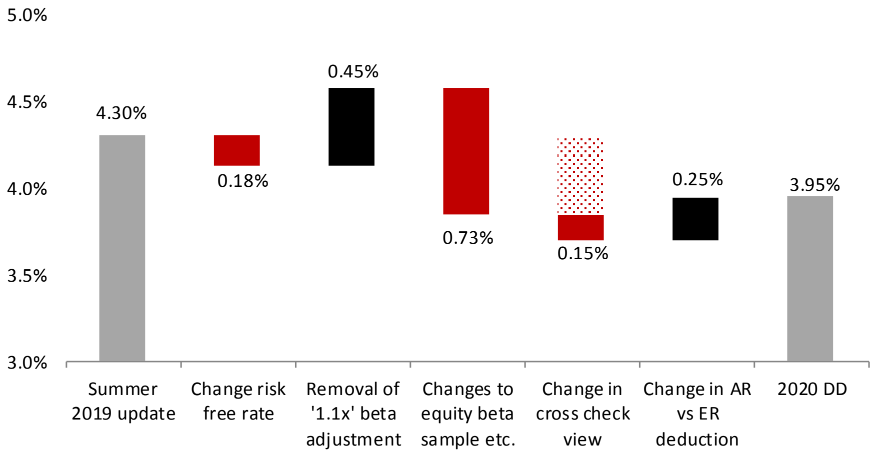
b. Used flawed or circular "cross checks" to lower this range further still; and

c. Made an unjustified 25bps reduction below Ofgem's own estimate of the cost of equity.

Even though Ofgem has removed its 1.1x beta adjustment, its proposed cost of equity has fallen, as Ofgem has simultaneously lowered its view of equity beta and cross checks

10. We welcome the fact that Ofgem has corrected at least one of the serious issues with its previous CAPM calculations – removing the" 1.1x adjustment" to its equity beta estimates. This adjustment was flawed and led to an equity beta that was not founded in finance theory.

11. Yet, rather than now estimating a higher allowed return, Ofgem has estimated one which is lower. The chart below shows how the various parameters have contributed to this.



The equity beta itself appears to be a "goal seek" to match Ofwat's CAPM value – not least because Ofgem has removed its weight on GB energy networks

12. This reduction in equity beta appears to be driven, almost entirely, by Ofgem's counterintuitive decision to remove or reduce the weight it places on asset beta estimates from its most obvious comparator: GB energy networks.

a. The company that previously informed the high point in its range, SSE, appears to have been removed altogether, with no weight being placed on past or present estimates.

b. The weight being placed on National Grid appears to be limited or none.

13. Having removed two of the more relevant data points it had, this leaves the analysis Ofgem presents in the draft determinations as depending entirely on a sample of water sector companies.

14. The result is a cost of equity goal seek to the levels recently estimated by Ofwat for its PR19 price control, because Ofgem is now also estimating a water sector cost of equity.

Ofgem uses flawed and circular cross checks to compound its mistake

15. At Ofgem's methodology decision, its cross checks supported a slightly higher cost of equity than its CAPM range, and it adjusted its cost of equity upwards accordingly.

16. To support its new range, Ofgem has had to come up with a revised set of cross checks. Changing cross checks such that they support the underlying assumptions obviously undermines their purpose.

17. Ofgem's new cross checks serve to adjust downwards a CAPM range that is already much lower than Ofgem's previous estimates. The changes in Ofgem's cross checks are tabulated below:

Cross check	May-19	Jul-20
Unadjusted OFTO IRR	5.1%	4.9%
Unadjusted Investment manager TMR	5.5%	5.0%
CAPM (0.75 beta) with investment manager TMR	4.0%	-
CAPM (0.9 beta) with investment manager TMR	-	4.3%
Infrastructure fund: disclosed asset valuation IRR	5.4%	-
Infrastructure funds: implied market IRR	-	4.2%
"Alternative" re-gearing relationship	-	3.2% - 4.1%
Market to Asset Ratios	-	4.2% (or less)

18. There are significant issues with Ofgem's new cross checks:

a. The newly added "alternative" re-gearing relationship cross check:

i) uses Ofgem's low equity beta, TMR and risk free rate as cross checks on themselves;

ii) is based on a re-gearing relationship that is flawed in finance theory terms; and

iii) departs from the standard re-gearing relationships adopted by the CMA in all its re-determinations of the cost of equity, including the recent NERL re-determination.

b. The newly added market to asset ratios cross check is flawed because it appears it:

i) is based largely on the water sector;

ii) fails to control for financial (cost of debt) outperformance;

iii) is based on a report that is much more cautiously couched than Ofgem recognises, and which also supports values up to 4.8%[1]; and

[1] On page 34, under the heading "*What implications might be drawn by Ofgem from this analysis?*", CEPA says that "*one interpretation*" is that Ofwat's estimate represents an upper limit but CEPA also admits there is still a "*legitimate discussion*" about differences in risk, concluding much more weakly that "*Ofgem's assumptions **at SSMD** are unlikely to lead to a material underestimation of the cost of equity*" (emphasis added; the SSMD value was a 4.8% real cost of equity).

iv) triple counts the supposed outperformance evidence that Ofgem also uses to support an allowed returns deduction and for setting GD2 cost benchmarks based on a tougher percentile.

c. The updated "un-adjusted investment manager TMR" is skewed downwards by Ofgem's choice of precise data point, rather than by underlying reductions in those forecasts.

19. Once we remove the flawed new cross check, correct the investment professional forecasts, and reflect CEPA's more nuanced conclusions, the result is a range that runs from about 4.2% to 5.8%.

20. Ofgem's cross checks do not support a reduction relative to Ofgem's updated CAPM range. They support an even bigger increase than was made at the sector specific methodology decisions.

Ofgem fails to recognise that energy networks are exposed to greater political and, certainly under these proposals, regulatory risk than their water sector counterparts

21. Ofgem should not focus only on *systematic* risk in its assessment of any risk differences with the water sector, since to do so omits *political and regulatory* risk. These represent a material part of the risks faced by investors in networks. Energy networks are exposed to greater regulatory and political risk than water networks since:

a. average energy bills represent a significantly higher cost to the electorate than water bills; and the energy sector is more likely to be in the public eye at any given time.

b. energy networks are more exposed to this risk any other part of the energy value chain, since they are a natural monopoly.

22. Greater political and public prominence can translate to greater regulatory risk. Based on Ofgem's apparent goal-seek to a lower cost of equity, along with Ofgem's apparent shift to ex post and discretionary regulation, this may be manifesting itself.

Ofgem's total market return remains too low

23. Ofgem has not explicitly consulted on its total market return. However, we continue to reiterate that Ofgem has re-interpreted the historical record on inflation as being consistent with CPI rather than RPI, and reduced its range downwards as a consequence.

24. Investors will not perceive this as meeting Ofgem's commitment, early in the RIIO-2 process, of ensuring the switch to CPIH inflation was value neutral.

While using an ultra-low risk free rate in CAPM methodology leads to a further under-estimate of the cost of equity

25. We have a fundamental concern with Ofgem's use of spot risk free rates based on gilts, which reflects factors other than the risk free rate for making long term investments in a corporate entity, such as convenience and liquidity premia.

26. Using a 20 year gilt, as Ofgem does, helps to reflect the long term nature of decisions to invest in energy network assets. However, it fails to reflect the unsuitability of gilt rates as a proxy for the

CAPM risk free rate. Significant changes are necessary; in particular a substantial uplift to the risk free rate on UK gilts should be applied.

The decision to not aim up will do nothing to support future investment

27. We have previously highlighted to Ofgem that the reasons for ensuring that the cost of equity is not too low have been repeatedly articulated by regulators, including the CMA:

> *Given the uncertainties in cost of capital estimates, we considered the cost of setting an allowed WACC that was too high or too low. If the WACC is set too high then the airports' shareholders will be over-rewarded and customers will pay more than they should. However, we consider it a necessary cost to airport users of ensuring that there are sufficient incentives to invest, because if the WACC is set too low, there may be underinvestment from BAA or potentially costly financial distress…Given the significance to customers of timely investment at Heathrow and Gatwick, we have given particular weight to the cost of setting the allowed WACC too low. Most importantly, we note that it is difficult for a regulator to reduce the risks of underinvestment within a regulatory period.*[2]

28. Insofar as Ofgem considers timely investment to be important, it should take the same approach.

29. Ofgem has recognised in its draft determinations that it legitimately provides incentives for companies to identify and avoid un-necessary cost in other parts of its price control mechanism; as an engine for ongoing productivity growth and to reveal cost reductions that can lead to significant savings for energy consumers once replicated over the longer term.

30. This legitimate application of incentive regulation does not mean that Ofgem can ignore the incentives that the cost of capital creates to invest. There is in fact a spectrum of company decisions that Ofgem needs to consider:

    a. companies need to meet many legal requirements, and cannot simply stop doing so; here Ofgem is under a legal duty to ensure licensees can finance the cost of this activity;

    b. there are a range of more discretionary investment decisions where Ofgem uses cost assessment and incentives to ensure efficiency; and

    c. amongst these discretionary investment decisions, there are some in particular that Ofgem will keenly want companies to identify and bring forward.

31. It is the last of these three where the incentive to invest is especially important.

While Ofgem's proposal to set an allowed cost of equity below its own estimate means that Ofgem is necessarily failing to finance the cost of equity…

32. Ofgem has recognised in its assessment of financeability that it has a duty to finance the efficient costs of equity holders.

[2] Competition Commission, A report on the economic regulation of the London airports companies (Heathrow Airport Ltd and Gatwick Airport Ltd), September 2007, page 49. https://webarchive.nationalarchives.gov.uk/20111202214947/http://www.competition-commission.org.uk/rep_pub/reports/2007/fulltext/532.pdf.

33. Yet by proposing to set a cost of equity below its own best estimate of the cost of equity (notwithstanding the fact that estimate is too low), Ofgem is *explicitly proposing not to fund the efficient cost of equity*.

… which is not remedied by the proposed ex post adjustment, since efficient companies might still be left under-funded

34. The "backstop" ex post adjustment mechanism does not address the issue of setting the allowed return below its estimated value; for example under Ofgem's proposal the gas transmission licensee might go unfunded for its cost of equity because gas *distribution* licensees, operating very different businesses and under a different set of price control arrangements, have outperformed their price controls. Similar examples could arise even within sectors; for instance if Ofgem over-funded some companies, but not others. No form of averaging across companies can protect from this potential outcome.

35. Worse still, the backstop mechanism also has the effect of further damaging already reduced incentives within the price control period, since it introduces a feedback loop whereby worse performance on incentives could contribute to a financial reward at the end of the period.

Ofgem has set productivity assumptions that are not supported by the evidence it presents

36. Ofgem proposes ongoing productivity of 1.2% for Capex and 1.4% for Opex.

37. This is a material parameter; some evidence must be needed to support a regulator's view on it. Yet Ofgem's apparent gerrymandering of the evidence continues:

   a. Ofgem goes straight to the top of the range CEPA estimates based on value added (VA) data, relying solely on "regulatory judgement" to justify this stance.

   b. Ofgem places no weight on CEPA's gross output (GO) measures, again, citing "regulatory judgement"; even though:

      i) these are internally consistent with the totex costs that productivity is applied to; and

      ii) CEPA stated in its advice to Ofgem that "*it is typically seen as good regulatory practice to consider the information provided by both methods [GO and VA] when developing a range for ongoing efficiency estimates.*"

   c. The additional 0.2% "innovation bump" assumption lacks any supporting evidence.

      i) CEPA "*identified no robust evidence for establishing a firm quantitative relationship*"; it only identified a causal relationship from innovation to productivity.

      ii) Ofgem must be assuming energy networks have out-innovated the rest of the economy (but it hasn't said this or tested it).

      iii) Ofgem's other argument is that energy network management can focus on productivity gains because they lack competition. To put it mildly, this is a speculative and unorthodox assessment of the consequences of monopoly power and would certainly need some corroboration before anyone could sensibly rely on it.

iv) It introduces an "innovation penalty", and this creates a direct disincentive for network companies to access innovation funding in future.

d. There is a double count, as Ofgem appears to have not properly stripped productivity assumptions out of GDN business plans.

e. Lastly, the productivity gains seen by networks over the last 20 years have been driven by operators taking measured risks, driven by strong incentives to improve performance. These incentives are being both significantly weakened and capped; and Ofgem cannot expect the same levels of productivity gains in this new environment.

While established regulatory good practice on cost benchmarking has been modified to set lower benchmarks based on an apples and pears comparison

38. At GD2 Ofgem has moved to a top-down totex approach for a large part of the cost base. We support this development as continuing the regulatory trend towards totex regulation – but we do not support the cost drivers, which place much weight on "workload", and therefore are directly controllable by the GDNs.

39. Ofgem has, however, set the GD2 efficiency benchmark at the 85th percentile, not the 75th percentile. This is a departure from regulatory good practice, which Ofgem is under a duty to have regard to.

40. Ofgem's argument focusses on underspend of allowances, which is flawed because:

a. GD1 allowances included weight on company plans, not just its benchmarks; and

b. It double counts Ofgem's argument for an allowed vs. expected returns deduction.

41. Ofgem's argument that it has improved its models for GD2, and therefore can place more weight on them, also appears contradictory to Ofgem's main argument. If the models are improved, why is Ofgem worried that companies will underspend the benchmarks?

The move to downwards only pass through of many cost efficiency savings will destroy one of the cornerstones of incentive regulation and raise long term costs to consumers

42. Even within the cost allowance baselines that are being provided, Ofgem is making significant use of uncertainty mechanisms to prevent companies benefitting from underspends.

> "*approximately 50% of baseline costs across gas distribution and transmission sectors will be linked to uncertainty mechanisms and PCDs to ensure companies are only paid for what they deliver*" (emphasis added)

43. This mentality is evident in Ofgem:

a. moving large swathes of cost allowances into uncertainty mechanisms;

b. introducing discretionary, after the event, assessment for many other costs;

c. using price control deliverables as an uncertainty mechanism, where the uncertainty trigger is whether companies will amend their plan; and

d. using the NARMs mechanism to claw back almost all of any cost savings from more efficient asset management.

44. This move to pass through for large parts of the cost base leaves network licensees only with residual incentives to minimise unit costs for work delivery. They will minimise the risks and regulatory burden they face if they stick to their initial plan. But the biggest savings to energy consumers can come from companies deploying effective asset management techniques to revise their plans on an ongoing basis.

45. The loss of incentives for companies to find ways to avoid costs altogether will therefore be damaging to long term productivity in the sector and thus costly to energy consumers.

46. At the same time the regulated networks are being exposed to greater risk, through the downside only nature of the many of the new pass through mechanisms, and the ex post regulatory judgements they will be exposed to.

Ofgem's proposed pre- and post-appeals framework is an obvious attempt to place a thumb on the scales which will undermine investor confidence

47. Ofgem is proposing to:

a. require companies to provide it with details of any potential appeal outside the statutory process, and, in fact, before it takes the decision which is actually subject to appeal; and

b. introduce a post appeals review policy which is either unnecessary (in its narrow formulation) or undermines the appeal regime (in the wider versions Ofgem reserves the right to adopt).

48. These proposals are either unnecessary or ultra vires and proposing them damages investor confidence.

2. Core document questions

49. In this section we respond to each of Ofgem's questions in its core document of the T2 and GD2 draft determinations consultation (the Consultation).

Consumer engagement groups

Q1 What role should Groups play during the price control period and what type of output should Groups be asked to deliver? Who should be the recipients of these outputs (companies, Ofgem and/or stakeholders)?

50. If Ofgem takes ahead its proposal for the groups to continue, they could play a role in scrutinising the annual stakeholder reports, ongoing execution of innovation strategies or risk management processes.

51. In deciding whether to continue the Groups, Ofgem should have regard to their ongoing cost, and judge whether the benefits will outweigh the costs.

52. Ofgem has also highlighted the potential options of company or sector specific groups. Company specific groups may be able to work more closely with companies through the development process. Sector specific groups might reduce costs, but only to the extent their remit is more limited in scope; they would also require different administrative arrangements.

Q2 What role should Groups take with respect to scrutinising new investment proposals which are developed through the uncertainty mechanisms?

53. The groups could perform a similar role to their activity scrutinising the business plan development process.

54. Ofgem would, however, still need to review the proposals and take the decisions in the same way it does now. Clarity about what role each body is playing is essential for good and proper governance.

Q3 What value would there be in asking Groups to publish a customer-centric annual report, reviewing the performance of the company on their business plan commitments?

55. We think building on the CEGs, by making them standing bodies and giving them a role within a price control period, could be a natural evolution of this feature of the process. However the specific option that Ofgem is consulting on sounds duplicative of the company's own annual report on performance and would add bureaucracy; it would be preferable for the group to contribute to the company's report, for example with some kind of statement of adequacy, rather than add to the number of stakeholder reports that are available.

Q4 What value would there be in providing for continuity of Groups (albeit with refresh to membership as necessary) in light of Ofgem commencing preparations for RIIO-3 by 2023?

56. As stated above, we think building on the CEGs, by making them standing bodies and giving them a role within a price control period, could be a natural evolution. To the extent a standing group has

the necessary understanding of the company's business and the price control process this may create some efficiencies by removing the need for a full induction process at RIIO-3. This should be set against the ongoing costs of a standing group.

Digitalisation

Q5 Will the combination of the two proposed Licence Obligations support the delivery of a digitalised energy system and maximise the value of data to consumers?

57. The first obligation, two-yearly and six-monthly reporting and updates, will provide some transparency over the progress of companies. If it is possible to build these requirements into existing reporting and information in it may help to avoid stakeholder fatigue.

58. However it is vital that Ofgem does let this slip into micro-management. For example, the requirements for updates on the action plan should not be so prescriptive as to rule out ongoing updates or a variety of formats (e.g. website updates, user emails etc.).

59. The second obligation, requiring companies to follow Ofgem's guidance on data practice, will depend heavily on the content of that guidance. Ofgem has asked for comments on this separately through its consultation on that guidance and so we provide no comments here.

Q6 Do you agree with our proposed frequency for publication of updates to the digitalisation strategy and the digitalisation action plan, respectively?

60. The frequency appears reasonable, provided that the requirement to publish updates on the digitalisation action plan is flexible enough to allow them to be stakeholder-accessible (See paragraph 58 above). Care should also be taken to allow alignment between the requirements of the DSO and Digitalisation strategies and to avoid unnecessary duplication.

Q7 What kinds of data do you think should comply with the data best practice guidance to maximise benefits to consumers through better use of data?

61. A focussed definition is more likely to deliver benefits to consumers. Too wide a definition is likely to result in information overload and unnecessary costs. Ofgem also has a duty to finance the costs that energy licensees incur in fulfilling their obligations; Ofgem must therefore be mindful of these costs when considering whether transparency of a particular type of data is likely to deliver sufficient consumer benefit that it would be in consumer interests overall.

Q8 Do you agree that the Groups could have an enduring role to work with the companies to monitor progress and ensure they deliver the commitments in their engagement strategies?

62. The groups could have an enduring role as part of the company process to develop their annual stakeholder reporting (e.g. as required under SLC50 of the ED1 electricity distribution licence, which sets out requirements for Business Plan Commitment Reporting).

Environmental outputs

Q9 Do you agree with our proposal to accept the proposals for an ODI-R for BCF and the other proposals set out above as EAP commitments and to require progress on them to be reported as part of the AER?

63. Given the diverse nature of environmental outputs, a reputational ODI appears reasonable, although we would not rule out that certain issues could warrant a different approach.

64. Ofgem should consider including the requirements to report against business plan environmental commitments as part of the main annual report on business plan commitments, to avoid an excessive number of publications.

65. We have not reviewed the specific company proposals and therefore make no comment on them.

Real price effects (RPEs) and ongoing efficiency

Q10. Do you agree with our proposed RPEs allowances? Please specifically consider our proposed cost structures, assessment of materiality, and choice of indices in your answer.

66. We disagree with Ofgem's entire approach to real price effects (RPEs). Our objections were set out in our response to Ofgem's T2 and GD2 methodology consultation.[3] In short, real price effects must be allowed for, but indexing allowances to other sectors or the wider economy on a year-to-year basis will add to the risks facing energy networks, when compared to fixed allowances.

67. In terms of our views on Ofgem's specific proposals surrounding indices and weights:

    a. It is sensible to use notional company cost structures where it is reasonable to think that the activities of the companies are comparable, e.g. within the sector.

    b. It would undermine the totex approach to regulation if Ofgem awarded different RPE allowances to specific companies because they had adopted a different business model (or had evaluated their cost structure using a different methodology). In light of this,

        i) Ofgem should assess whether it is indeed appropriate to set company specific assumptions in transmission;

        ii) this would only be the case if the activities are simply not comparable.

    c. The specific indices being proposed are typically similar to those that have been used in the past to estimate fixed RPE allowances. They therefore may represent the best available indices that Ofgem is willing to contemplate.[4] But we do not think Ofgem can

[3] Northern Powergrid, March 2019, response to RIIO-T2 and GD2 sector methodology response, cross sector questions document, pages 22-23, paragraphs 131-137

[4] Direct measures of benchmarked pay settlements within the relevant sectors are an alternative that would better reflect the pay environment in each relevant sector at any one point in time. But Ofgem has been unwilling to date to gather and use such information from the relevant companies in order to set RPEs, even for sectors where it would be able to take a benchmark across the companies (such as electricity distribution).

construct an index that will accurately reflect the year to year cost pressures faced by energy networks from these indices. These inaccuracies could work in different directions at any one point in time, but it means that over the price control period energy networks are being exposed to additional risk. For example:

i) ONS average weekly earnings estimates will reflect changes in the mix of employees across the economy, not just wages, for example including any shift towards gig economy work, or specific sectors shedding employment at one particular point in time, all of which can affect average earnings.

ii) The BEAMA electrical engineering index reflects the changing wages of engineering labour involved in electrical manufacture, which we presume Ofgem has previously viewed as a reasonable long term benchmark for energy networks, but is unlikely to reflect the cost pressures faced by energy networks at any given point in time.

iii) We assume the PAFI civil engineering labour index is the same index as was used at RIIO-1, which reflects pay settlements agreed in negotiation between the buildings trades unions and the Construction Industry Joint Council, and so reflects changes in labour rates in the wider construction industry, not just civil engineering labour. Again, this may reflect market conditions well beyond the markets for civil engineering labour that energy networks would require at any given point in time.

d. Ofgem is proposing to allow zero RPEs on any categories of costs it regards as "immaterial", while still applying a productivity assumption. If the evidence supports an RPE or on or close to zero, this would seem reasonable. But if Ofgem assumes zero RPEs simply because the category of costs is small, or there is an absence of evidence on the level of RPEs for that cost, this is not reasonable. This is because:

i) The price of inputs, on average across the economy, will rise faster than measures of inflation.[5]

ii) Ofgem cannot just ignore this positive relationship, which supports a positive starting assumption for RPEs (for any "immaterial" categories of cost).

e. Ofgem is ignoring the effect of COVID-19 on its chosen measures of pay RPEs.

i) Energy networks continued to operate during the pandemic and cannot be expected to match measures of RPEs that included reduced pay due to the furlough scheme[6];

ii) the longer term effects of COVID-19 on the various pay measures are more difficult to forecast but unlikely to be reflective of cost pressures facing energy networks.

[5] Measures of inflation will be lower than the increase in input prices due to offsetting improvements in productivity.

[6] Nominal regular pay growth for April to June 2020 is negative for the first time since records began in 2001; yet network companies are unlikely to have furloughed many (if any) of their staff and therefore cannot have benefitted from this.

Q11. Do you agree with our proposed ongoing efficiency challenge and its scope?

68. We do not agree with Ofgem's proposed approach.

69. In common with other parts of the settlement, such as Ofgem's assessment of the cost of capital, the proposed approach has every appearance of a regulatory goal seek to choose the least advantageous parameter for the regulated companies even in the face of strong opposing evidence.

70. This is a material parameter; some evidence must be needed to support a regulator's view on it. Yet Ofgem's apparent gerrymandering of the evidence continues:

   a. Ofgem goes straight to the top of the range CEPA estimates based on value added (VA) data, relying solely on "regulatory judgement" to justify this stance.

   b. Ofgem places no weight on CEPA's gross output (GO) measures, again, citing "regulatory judgement"; even though:

      i) these are internally consistent with the totex costs that productivity is applied to; and

      ii) CEPA stated in its advice to Ofgem that "*it is typically seen as good regulatory practice to consider the information provided by both methods [GO and VA] when developing a range for ongoing efficiency estimates."*

   c. The additional 0.2% "innovation bump" assumption lacks any supporting evidence.

      i) CEPA "*identified no robust evidence for establishing a firm quantitative relationship*"; it only identified a causal relationship from innovation to productivity.

      ii) Ofgem must be assuming energy networks have out-innovated the rest of the economy (but it hasn't said this or tested it).

      iii) Ofgem's other argument is that energy network management can focus on productivity gains because they lack competition. To put it mildly, this is a speculative and unorthodox assessment of the consequences of monopoly power and would certainly need some corroboration before anyone could sensibly rely on it.

      iv) It introduces an "innovation penalty", and this creates a direct disincentive for network companies to access innovation funding in future.

   d. There is a double count, as Ofgem appears to have not properly stripped productivity assumptions out of GDN business plans.

   e. Lastly, the productivity gains seen by networks over the last 20 years have been driven by operators taking measured risks, driven by strong incentives to improve performance. These incentives are being both significantly weakened and capped; and Ofgem cannot expect the same levels of productivity gains in this new environment.

71. In other words, it is deeply flawed, in terms of the logic and empirics that Ofgem uses to support its position, includes “double counts”, goes against what Ofgem’s own advisers, CEPA, describe as regulatory good practice (to which Ofgem has a duty to have regard), and will dis-incentivise network companies from using innovation funding in future. On every count, it is a regulatory catastrophe.

72. Ofgem should remove the 0.2 percentage point innovation adjustment, place weight on the GO measures (as well as VA), select the mid-point of the range to take a balanced view, and move on.

Reopeners

Q12 Do you agree with our proposed common approach for re-openers?

73. We disagree with two aspects of Ogem’s proposals and have a suggestion on a further aspect:

   a. we oppose Ofgem allowing itself to trigger reopeners at any time during a price control period;

   b. Ofgem should not give itself the ability to reject re-opener application simply because it did not contain all the information that Ofgem subsequently decides that it needs to take an informed decision; and

   c. we suggest that Ofgem introduces an “updated submission” window to its process.

74. If Ofgem gives itself the right to trigger reopeners at any time, it will make itself more exposed to any political pressure that can from time to time arise. This reduced insulation against political pressure will in turn expose investors to additional risks, raising the cost of capital to the detriment of energy users. Furthermore, the process Ofgem proposes at paragraph 7.26 of the consultation, which appears limited to publishing a direction and consulting for 28 days, appears far too limited to provide network companies and their investors any real protection from this regulatory risk. A longer process, with multiple stages (including informal consultation on Ofgem’s analysis) should be introduced.

75. Ofgem should not give itself the discretionary ability to reject reopener requests out of hand because it considers the application to have not contained 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.

76. We do not oppose Ofgem bringing forward the reopener window by four months, from May until the last week of January, but there are pros and cons to this and we have one suggestion. The change to timetable means that:

a. Ofgem will afford itself additional time for assessment, and also more time to obtain any additional information this it thinks it may require to take a decisions, which is positive and has our support; but

b. submissions will need to use additional forecast information (since the then current regulatory year will not yet be completed), which will reduce the amount of information available to the process.

77. In light of these pros and cons, 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.

78. Continuing to use the RIIO-1 materiality thresholds, and the proposed new thresholds that would allow for the aggregated effect of multiple re-openers, seems reasonable.

Q13 Do you agree with our [Co-ordinated Adjustment mechanism] proposals on a materiality threshold, a financial incentive, a 'foreseeable' criterion, and who should trigger and make the application?

79. We have no objections to the proposals regarding materiality thresholds and the potential for commercial financial incentives to be incorporated by companies in their proposals (to the extent these are reasonable). We also agree with Ofgem that the potential criterion that the transfer could not have been "foreseeable" is not necessary. Consumers are in any case protected by the design of the mechanism, since the majority of any benefits from any transfer appear likely to flow to them.

Q14 Do you consider that two application windows, or annual application windows, are more appropriate, and should these be in January or May?

80. We do not have strong views on this point.

81. On the one hand, an annual process would appear to deliver greater fluidity than bi-annual. On the other hand, the excluded services framework and commercial contracting between licensees already allows for a fluid, any time of year, process for achieving similar outcomes.

Q15 Do you consider that the RIIO-1 electricity distribution licences should be amended to include the CAM, or wait until in 2023 at the start of their next price control?

82. We are neutral on this issue.

83. On the one hand, provided that licensee agreement to any adjustments is necessary for the co-ordinated adjustment mechanism to operate (as we understand it will be), applying it earlier to ED1 does not seem to be detrimental to the integrity of the ED1 price control or the rights of licensees.

84. On the other hand, we can see little or no requirement for the CAM, since electricity distributors can already provide any services (or assets) that other network operators might require as an excluded service; and would also expect to be able to procure any services they require from other network operators.

Q16 Do you agree with our proposed re-opener windows for cyber resilience OT and IT, and our proposal to require all licensees to provide an updated Cyber Resilience OT and IT Plan at the beginning of RIIO-2?

85. If a reopener is necessary, two windows in a five year price control period seems excessive. A single window, around the mid-point, would be more proportionate.

86. To the extent that some licensees have already submitted adequate cyber plans, it seems disproportionate for all licensees to be required to submit updated plans.

87. In general we think Ofgem's proposals for cyber resilience carry risks for energy consumers, particularly as they will create significant cost boundaries within the price control, and will damage incentives for licensees to ensure their cyber costs are efficient. These risks for energy consumers will be made worse if Ofgem allows its approach to extend into micro-management. We set out this view in more detail in our response to Ofgem's T2 and GD2 methodology.[7]

Q17 Do you agree with our proposal for the Non-operational IT and Telecoms capex re-opener?

88. A reopener should not be necessary for those IT and Telecoms costs that are not driven by new external obligations, as it should be possible to make allowance for these costs in baseline totex.

89. Having any reopener in this area will create problematic boundaries within the price control cost base. Introducing a reopener for "business as usual" costs, simply because there is some uncertainty over the level of expenditure, will further damage the incentives for licensees to minimise costs within the RIIO-2 period, causing detriment to consumers in the form of higher costs and a failure to develop and reveal efficiencies.

90. To the extent that a clear external driver, such as a change in legislation or a change by Ofgem of licence requirements, triggers additional expenditure, it may be reasonable to allow a reopener.

Q18 Do you agree with our approach to using a re-opener mechanism for changes to government physical security policy?

91. We agree with the re-opener but disagree with Ofgem's proposal to impose a materiality threshold.

92. The key to maintaining strong incentives will be ensuring that only changes in the sites at which government requires enhanced security will trigger the reopener, and not licensee decisions. Once the government requirements are known, fixed allowances should ideally be set, and any cost variances included within the main totex incentive mechanism, to help driver lower costs for energy consumers. With this in place, the distorting effects of a reopener will be minimised.

93. The proposal to impose a materiality threshold is however flawed because it:

[7] Northern Powergrid, 2019, T2 and GD2 sector methodology consultation response, sector specific question responses paragraphs 124-130

a. is inconsistent with Ofgem's position on other reopeners that will have no materiality threshold e.g. the IT and telecoms reopener;

b. is un-necessary, since the reopener can only be triggered by a clear external driver, which minimises the risk of any un-necessary administrative burden;

c. could cause multi-million pound requirements imposed on individual licensees by government to go unfunded, as Ofgem's materiality threshold itself is quite material; and

d. ignores Ofgem's duty to ensure the network licensees can finance the cost of their activities.

94. Ofgem's argument that a materiality threshold is necessary to avoid administrative burden carries no water when Ofgem proposes no threshold for other reopeners, and because the government considers it worthwhile incurring a significant administrative burden to progress such investments.

Q19 Do you agree with our approach regarding legislation, policy and standards?

95. We agree with Ofgem's approach in this area.

96. Reopeners are best suited to specific, known, and externally driven reasons that could well impose additional costs on the licensees, and are highly unlikely (or simply couldn't) cause lower costs.

97. In such instances they cause the least damage to incentives for licensees to manage their costs, especially if the reopener can be triggered as soon as the external change is known, so totex allowances can be revised on a forward looking basis (allowing efficiency incentives to act thereafter).

98. There are many general business risks carried by licensees. These could at times cause higher costs, or lower costs, and it is a longstanding part of GB network regulation that licensees are expected to manage these risks and minimise their costs in light of them. Reopeners should not be introduced for such risks.

Q20 Do you agree with our overall approach to meeting Net Zero at lowest cost to consumers? Specifically, do you agree with our approach to fund known and justified Net Zero investment needs in the baseline, and to use uncertainty mechanisms to provide funding in-period for Net Zero investment when the need becomes clearer?

99. We agree with Ofgem's proposals, broadly speaking, to include justified costs in the baselines; but to keep options open on any particularly uncertain aspects of Net Zero. This will help avoid incurring sunk costs too soon, and wasting money.

100. However, we do not agree that Ofgem's overall approach to RIIO-2 regulation will help achieve net zero at the lowest cost to consumers.

101. Even within the cost allowance baselines that are being provided, Ofgem is making significant use of uncertainty mechanisms to prevent companies benefitting from underspends.

"*approximately 50% of baseline costs across gas distribution and transmission sectors will be linked to uncertainty mechanisms and PCDs <u>to ensure companies are only paid for what they deliver</u>*" (emphasis added)

102. This mentality is evident in Ofgem:

a. moving large swathes of cost allowances into uncertainty mechanisms;

b. introducing discretionary, after the event, assessment for many other costs;

c. using price control deliverables as an uncertainty mechanism, where the uncertainty trigger is whether companies will amend their plan; and

d. using the NARMs mechanism to claw back almost all of any cost savings from more efficient asset management.

103. This move to pass through for large parts of the cost base leaves network licensees only with residual incentives to minimise unit costs for work delivery. They will minimise the risks and regulatory burden they face if they stick to their initial plan. But the biggest savings to energy consumers can come from companies deploying effective asset management techniques to revise their plans on an ongoing basis.

104. The loss of incentives for companies to find ways to avoid costs altogether will therefore be damaging to long term productivity in the sector and thus costly to energy consumers.

105. At the same time the regulated networks are being exposed to greater risk, through the downside only nature of the many of the new pass through mechanisms, and the ex post regulatory judgements they will be exposed to.

106. In other words, Ofgem has omitted from its RIIO-2 design the strong incentives that were originally intended to be a cornerstone of RIIO, and how RIIO would keep costs low through the transition to net zero.

107. Ofgem should be using external triggers for reopeners or allowing costs wherever possible. Instead its decisions appear to be driven more by whether companies are spending money; in other words, cost pass through. In one case, the ESO, it is literally applying pass through. While this will deliver lower scope for outperformance by licensees against incentive schemes, the loss of incentives will also lead to higher costs over time. This increase in inefficiency will over the course of decades cost consumers significant amounts.

Q21 Do you think the package of cross sector and sector-specific UMs provides the appropriate balance to ensure there is sufficient flexibility and coverage to facilitate the potential need for additional Net Zero funding during RIIO-2?

108. The package of cross sector uncertainty mechanisms is weighted too far in favour of flexibility.

109. Some mechanisms may even be duplicative, such as the net zero reopener and the heat policy reopener. But this is not in and of itself a problem, as the heat policy reopener can be better tailored to that specific issue than the net zero reopener could be.

110. However, we do not support Ofgem's over-use of sector specific uncertainty mechanisms in general.

111. In particular we oppose the widespread use of price control deliverables (PCDs) as uncertainty mechanisms. Where Ofgem uses PCDs in this way, with uncertainty mechanism clawback provisions, the uncertainty mechanism is triggered entirely by licensee decisions. These decisions include whether the licensee takes ahead the exact work set out in its plan or instead finds an alternative, for instance efficient deferral, findings efficient alternatives, or using different inputs. Because the licensee's allowances will depend directly on its decisions to spend, not spend, or find an alternative, Ofgem has in effect implemented pass through regulation, with all the damage to incentives that this brings about.

Q22 Do you have any views on our proposed approach to a Net Zero re-opener?

112. We do not support Ofgem's proposed approach.

113. However it does not surprise us. At many turns, where Ofgem has the choice in RIIO-2 of either maintaining an ex ante settlement with strong incentives, or moving towards a set of arrangements based on pass through at the regulators discretion, Ofgem has chosen the latter.

114. Although Ofgem has said that it wants to minimise the risk it will "*miss opportunities in RIIO-2 to facilitate the achievement of the Net Zero target*" that seems unlikely in a five year price control settlement that has been well designed; and if the opportunity were so important, and Ofgem and the relevant licensees all agreed, Ofgem could in any case amend the price control settlement through licence modification.

115. What Ofgem has failed to recognise is the cost to energy consumers, through weaker ongoing incentives to find cost savings, of this type of broad based discretionary mechanism that can allow companies and Ofgem to make amendments to the price control settlement for a whole host of reasons.

116. To sum up, our views on the net zero re-opener remain the same as those set out on the front page of our response to Ofgem's net zero reopener consultation; and a narrow definition should be used.

Innovation funding

Q23 Do you agree with our proposals for the RIIO-2 Strategic Innovation Fund?

117. We can see why Ofgem has made the proposals it has, although we still consider that limiting the funding to energy transition issues risks ruling out funding for forms of innovation that would be of benefit to energy consumers, but which would not be commercially viable under the cost or output incentive schemes (e.g. where the benefits are spread over multiple price control periods).

118. In the detail, it should be remembered that the best innovation projects produce a multitude of customer benefits. In this context, Ofgem needs to be careful not to define the qualification criteria for projects too tightly. A project may be predominantly about driving forward Net Zero but it may

also (for example) deliver system resilience benefits as well. Ofgem needs to ensure that such a project could still be considered and the 'added value' from the innovation providing extra justification for a project as opposed to disqualifying it from consideration.

Q24 Do you have any comments on the additional issues that we seek to consider over the coming year ahead of introducing the Strategic Innovation Fund?

119. The Strategic Innovation Fund is significantly different to the Network Innovation Competition that it replaces. As such, the additional steps are essential in order to design and put in place the new structure. Of most significance is the requirement to set out the role of the other institutions that will need to operate with Ofgem in implementing this new strategic innovation framework. This is not visible as an explicit action in the next steps.

Q25 Do you agree with our approach to benchmarking RIIO-2 NIA requests against RIIO-1 NIA funding?

120. Yes. It is reasonable that companies are required to explain and justify how RIIO-2 NIA requests compare to the level received in RIIO-1.

Q26 Do you agree with our proposal that all companies' NIA funding should be conditional on the introduction of an improved reporting framework?

121. Yes. Companies are making improvements already as is noted by Ofgem. But we recognise that this may be taken further.

Q27 What are your thoughts on our proposals to strengthen the RIIO-2 NIA framework?

122. The proposals to strengthen the NIA framework, targeting impact and value from the expenditure, are reasonable.

123. We agree with the action to assist third parties to understand better the requirements for intellectual property rights when accessing NIA funding. It is a recurring feature of our engagement with third parties that this is misunderstood. Better understanding should enable more efficient and effective engagement with third parties. It remains to be seen whether it would enable more third parties to be involved since we find that the 'open IP' nature can cause parties to withdraw; preferring instead a funding source that protects their IP.

Q28 Do you have any additional suggestions for quality assurance measures that could be introduced to ensure the robustness of RIIO-2 NIA projects?

124. No, we have nothing further to add.

Q29 Do you agree with our proposals to allow network companies and the ESO to carry over any unspent NIA funds from the final year of RIIO-1 into the first year of RIIO-2?

125. Yes, it is positive for customers that innovation is not shut down and then restarted during the transition from one price control period to the next.

Q30 Do you agree with our proposal that all work relating to data as part of innovation projects funded via the NIA and SIF will be expected to follow Data Best Practice?

126. The principle is appropriate but, recognising that Data Best Practice is still being defined, Ofgem should not at this time mandate this for all projects. Instead, akin to the treatment of IPR in the Network Innovation Competition, it should simply ensure additional scrutiny for any project that does not agree to the default Data Best Practice guidelines.

127. This would enable a project to not comply for good reason – for instance if the costs of following the Data Best Practice did not outweigh the value. For example, for a project with a very small amount of data, is there a less onerous approach that may be implemented? The overhead of running all the best practice data processes may not be proportionate for such a project.

Competition

Q31 Do you agree with our proposed position on late competition?

128. We agree with Ofgem's proposed approach to late competition, as set out in the box on page 110 of the Consultation.

129. Our reasoning is as follows.

a. It is appropriate to include projects that must go ahead in the near-term in baseline funding, since the various competition frameworks might entail delays.

b. We agree with Ofgem's continued application of its principles for competition (e.g. recognition of instances where projects may not be adequately "separable").

c. Where Ofgem is including major projects in an uncertainty mechanism it seems reasonable to decide later whether the project will be subject to competition.

d. We agree with Ofgem that the competition framework is less likely to deliver financing benefits, once the periodic "resetting" of the price control cost of debt is recognised.

130. We cannot say whether Ofgem's decisions about specific projects are appropriate as we are not familiar with the projects.

Q32 Do you agree with our proposed approach on early competition?

131. We agree with Ofgem's proposed approach to early competition in transmission and gas distribution, as set out in the box on page 117 of the Consultation.

132. In particular, it is appropriate that projects included in baseline funding will not be subject to early competition. This removes uncertainty and avoids the risk of sunk project development costs.

Business plan incentive and customer value propositions

Q33 - Q36 [requests for views on company pass / failure assessments under stage 1 of the BPI, and on treatment of customer value proposition proposals]

133. We have not reviewed the relevant business plans or customer value propositions through the lens that would be necessary to respond to these questions.

Q37 Do you agree with our proposed clawback mechanism to treat received CVP rewards?

134. Ofgem stated in its T2 and GD2 methodology decision that "*The reward will be reflective of this additional value. The reward may be linked to delivery where relevant.*"

135. Therefore Ofgem has options depending on the specific nature of the customer value proposition (CVP):

    a. in cases where the relevant value of the CVP is the delivery it is reasonable to create a clawback mechanism (if the reward is being provided in full in the initial settlement)

    b. in any cases where the value of the CVP is the "plan" itself, e.g. by creating a blueprint that other licensees could roll out, there should be no clawback (as the licensees delivery is not relevant to the main benefit of its proposal).

136. In terms of the design of a clawback mechanism:

    a. It should be based on a set of clear delivery milestones that are set at the outset.

    b. Ofgem should assess whether these milestones are being met on a timely basis, so that companies can take informed decision on whether to continue investing in their CVP (or abandon it and forego the reward for any milestones not yet met).

    c. It should not become a discretionary, after the event, assessment of company delivery against vague milestones.

137. These steps are necessary to avoid the CVP mechanism carrying a significant regulatory risk to licensees which would itself deter CVPs from being proposed and taken ahead.

138. On the topic of the ongoing CVP framework, although not regarding clawback, we agree with Ofgem's suggestion that annual reporting on the progress of any customer value propositions might be included as part of the company's main annual report on progress against its business plan. This will help avoid excessive numbers of publications and provide stakeholders with a "single source".

Price control appeals

139. Ofgem is proposing to:

    a. require companies to provide it with details of any potential appeal outside the statutory process, and, in fact, before it takes the decision which is actually subject to appeal; and

b. introduce a post appeals review policy which is either unnecessary (in its narrow formulation) or undermines the appeal regime (in the wider versions Ofgem reserves the right to adopt).

These proposals are either unnecessary or ultra vires and proposing them damages investor confidence.

Q38 Do you have any views on the interlinkages explained throughout this chapter?

140. The question as to how consider interlinkages within price control decisions was considered by the Competition and Markets Authority (the "CMA") in some detail in the Northern Powergrid appeal and the British Gas appeal in 2015.

141. The CMA provided that:

> *We consider that the question as to whether there are sufficient links between the parts of the Decision which are challenged and parts which are not challenged must be decided on a case-by-case basis taking into account the circumstances of each case. Where there are such links, we would, in the first instance, have expected GEMA to have highlighted these and addressed them in its response. GEMA merely stated in its Response that the decision is 'made up of a number of discrete but inter-connected determinations that together give rise to the decision itself'. We accept, however, that if, in the evidence submitted to the CMA, such links become apparent, we may take this into account where appropriate*.[8]

142. The CMA then restated this position in its Open Letter to Ofgem dated 30 October 2019, cross-referencing the paragraph above.[9]

143. The Draft Determination seeks to reduce the price control to three pillars - outputs, allowances and mechanisms to balance risk between consumers and companies - and then points out that at a macro level they have a relationship to one another. This is nothing more than a reassertion that everything in the price control is related to everything else, and so, just like last time, it clearly doesn't meet the test set out by the CMA.

144. Furthermore, Ofgem's position on interlinkages would render any challenge to any aspect of the price control down to a redetermination of the whole decision. This is not how the appeal mechanism set out in the statue works. The CMA may allow an appeal only where it is satisfied that the decision appealed was 'wrong' and the CMA must limit its consideration to the specific grounds of appeal, to the extent that such grounds are raised by the appellants. It is time that Ofgem accepted this.

[8] Paragraph 3.51 Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc v the Gas and Electricity Markets Authority: Final Determination.

[9] Paragraph 14 of the Open Letter.

Q39 Are there other interlinkages within our RIIO-2 package that you think are relevant to the three pillars identified in this chapter?

145. There are likely to be numerous instances where specific calculations used by Ofgem in its settlement have direct knock-on consequences for another calculation and value used in the price control decision. These interlinkages will be enumerated in Ofgem's price control calculations. By describing them on the face of its decisions, and also through providing the relevant calculations to the affected parties, Ofgem will have set them out transparently and appellants will be able to take them into account in any appeal they make.

146. Whether any interlinkages are relevant to any given appeal would need to be considered in depth by the CMA based on the specific facts of that appeal.

Q40 Do you have any views on our proposal to include a statement of policy in Final Determinations that in appropriate circumstances, we will carry out a post appeals review and potentially revisit wider aspects of RIIO-2 in the event of a successful appeal to the CMA that had material knock on consequences for the price control settlement?

147. We remain of the view that the proposed statement of policy would be unnecessary and risks undermining the statutory role of the CMA and the integrity and transparency of the appeal process.

148. Ofgem now cites a non-exhaustive list of two scenarios where it considers such a review may be appropriate. Where:

a. The CMA quashes the decision(s) appealed and remits to Ofgem for reconsideration with a direction that Ofgem reconsider the decision and consider interlinkages; or

b. The CMA quashes the decision(s) appealed, retakes the decision itself but directs Ofgem to consider interlinkages.

149. In both these examples Ofgem would have no choice but to consider the interlinkages and what to do about them. Having a policy that confirms this doesn't do any harm, but it would remain the case whether Ofgem adopts the statement of policy or not.

150. If Ofgem expands the instances where it would enact such a review beyond these then this will undermine the statutory role of the CMA and the integrity and transparency of the appeal process.

Q41 Do you have any views on the proposed pre-action correspondence, including on the proposed timing for sending such to Ofgem?

151. In its Open Letter the CMA explains 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.[10]

152. This clearly represents good practice. If appellants are obstructive then the CMA will take this into account in its cost order. However Ofgem's construction of what this means for pre-appeal conduct is lopsided and stretches the CMA's statement well past the credible.

153. Ofgem's position is that it expects potential appellants to:

> *[c]ome forward to clearly explain their intention to appeal, the element(s) of the RIIO-2 price control that they intend to appeal, the scope of that appeal including, in sufficient detail, the alleged errors, and why that particular component(s) of the price control is wrong having regard to interlinked aspects of the decision*.
>
> And
>
> *send pre-action correspondence at a sufficiently early stage, between the publication of Final Determinations and ahead of the appeals window opening. We would expect to receive this correspondence in the period from early December 2020 to early February 2021 - after the publication of Final Determinations and before we are due to publish a decision on the corresponding RIIO-2 licence conditions.*

154. 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 virtually certain that that any appellant will already have engaged with Ofgem in detail before Ofgem 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 Ofgem thinks it is entitled to in the timeframe Ofgem expects.

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

155. Ofgem also provides that

> *[i]n line with the approach set out the CMA in its open letter to the Authority we would expect that any interlinkages that exist between [Ofgem's three] pillars … are in the first instance raised by an appellant (and wider parties) in the context of any CMA appeal so that each element of our proposed price control determinations is viewed in its proper context.*

In fact the Open Letter provides that:

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[10] Paragraph 12 of the Open Letter.

> *[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*[11]

156. Before going on to add that:

> *[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]*[12]

157. It follows, then, that the first instance at which interlinkages would be addressed are in Ofgem's 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.

158. 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, Ofgem shifts from being a decision maker to a defendant, on an equal footing with the claimant.

159. 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.

Covid-19

Q42 Do you think we need specific mechanisms in RIIO-2 to manage the potential longer-term impacts of COVID-19? If yes, what might these mechanisms be?

160. Ofgem seems not to have considered the potential impacts of COVID-19 on licensee ongoing productivity (which it has set based on long term historical estimates) and also on the real price effects (which it has set on a short term basis, using observations from other sectors in the economy).

161. We think Ofgem should abandon its RPE index approach, and set the price control based on a consistent set of long term variables. But if Ofgem wishes to continue its short term RPE indexation policy (with which we disagree) it should take into account shorter term and forward looking productivity estimates.

[11] Paragraph 14 of the Open Letter.

[12] Paragraph 15 of the Open Letter.

162. We would not advocate yet another discretionary reopener mechanism to reset these parameters at a later date since this would introduce further regulatory risk and also further undermine incentives to minimise costs.

3. Finance questions

163. In this section we respond to each of Ofgem's questions in its finance document.

Allowed return on debt questions

FQ1. Do you agree with our approach to estimating efficient debt costs and setting allowances for debt costs?

164. We agree with the approach, broadly speaking, of setting a trailing average that is expected to mirror the cost of debt of a sector, including its historically issued debt and all its issuance costs.

FQ2. Do you agree with our proposal to use the iBoxx GBP Utilities 10yr+ index rather than a combination of iBoxx GBP A and BBB 10yr + non-financial indices?

165. Using an index of utilities bonds to estimate the cost of debt for utilities seems reasonable.

166. We also do not think it is especially financially material. Ofgem is setting its trailing average to mirror the expected cost of debt of the sector, therefore the fact the utilities index averaged at a lower level than the iBoxx corporates index during the financial crisis will "come out in the wash".

167. Whatever index is used, it is important that Ofgem ensures the cost of debt from the index calculation mirrors the full expected cost of debt that the relevant networks, including issuance.

168. We therefore also agree with Ofgem's proposal to make separate allowance for issuance costs. It is however not clear to us whether Ofgem's calculations include two factors that, in our experience, would be relevant to the evaluation of issuance costs on *historically issued debt*:

a. The coupon on our historically issued debt has almost always been "snapped" to 1/8 of a percentage point below the true cost of the debt (the bonds have been, in effect, sold at a small discount to the face value). On average, the true cost of the debt has been about 6 basis points above the coupon.

b. Many bonds issued in the early to mid-2000s will have benefitted from a credit wrap, and so would have been AAA rated (at the time of issue) with the commensurate reduction in the coupon. These credit wraps did not come free. Ofgem should account for the full cost of this debt, including the wrap, where it has been issued. In our experience wrap fees have been in the region of 25bps; Ofgem would need to obtain data from other licensees in the relevant sectors as to which of their bonds were wrapped at issue.

FQ3. Do you agree with our proposal that the RAV growth profile of SHET continues to be materially different to other networks and therefore warrants continuation of a bespoke RAV weighted allowance calculation?

169. We agree that, to the extent a particular network or sector has a very different RAV growth or corporate history to another, it is appropriate to calibrate a different cost of debt index for that network or sector.

170. We have previously included evidence in consultation responses that we considered to be relevant to this question and therefore do not repeat it here.[13]

Cost of equity questions

FQ4. Do you have any views on the model to implement equity indexation, as published alongside this document, (the "WACC allowance model.xlsx") or on the annual update process?

171. We have a fundamental concern with Ofgem's use of spot risk free rates based on gilts, which reflects factors other than the risk free rate for making long term investments in a corporate entity, such as convenience and liquidity premia.

172. Using a 20 year gilt, as Ofgem does, helps to reflect the long term nature of decisions to invest in energy network assets. However, it fails to reflect the unsuitability of gilt rates as a proxy for the CAPM risk free rate. Significant changes are necessary; in particular a substantial uplift to the risk free rate on UK gilts should be applied.

173. ENA's submission to the Competition and Markets Authority (CMA) re-determinations for PR19 highlights, based on an Oxera report, that:

a. Academic literature supports gilts benefitting from a convenience premium which pushes down any estimate of the risk free based on them, of the order of 30-90 basis points.

b. Even the lowest risk corporate would have to pay a premium above government debt, and that academic literature cites practitioners as sometimes using corporate risk free rates rather than government rates in CAPM models.

c. The RFRs assumed by sell-side analysts covering utilities in the UK are consistently higher than the spot yields on ILGs.

d. Addressing these issues with the risk free rate, by adopting a higher level more reflective of corporate reality, resolves the issue identified by the CMA and highlighted by Ofgem at paragraph 3.70 regarding the relationship between WACC and gearing, without the need for a change to the standard approach to 're-gearing' in finance theory and regulatory practice.[14]

174. As a consequence of these significant issues we offer no detailed comments on the specific indexation calculations that Ofgem has published.

[13] Northern Powergrid, 2019, ED2 framework open letter response, page 54

[14] ENA, June 1 2020, Submission to the CMA on the PR19 price determinations, pages 2-5, paragraphs 2-2.12

FQ5. In light of RIIO-2 Draft Determinations and Ofwat's final determinations for PR19, do you believe that energy networks will hold similar systematic risk during RIIO-2 to water networks during PR19?

175. This question raises important issues with Ofgem's equity beta estimation.

176. The equity beta itself appears to be a "goal seek" to match Ofwat's CAPM value – not least because Ofgem has removed its weight on GB energy networks

177. This reduction in equity beta appears to be driven, almost entirely, by Ofgem's counterintuitive decision to remove or reduce the weight it places on asset beta estimates from its most obvious comparator: GB energy networks.

   a. The company that previously informed the high point in its range, SSE, appears to have been removed altogether, with no weight being placed on past or present estimates.

   b. The weight being placed on National Grid appears to be limited or none.

178. Yet Ofgem's use of table 10 to justify the exclusion of SSE is flawed, because:

   a. the table demonstrates that SSE generates a higher share of its operating income from GB energy network assets than National Grid; making it highly relevant.

   b. SSE's expected exposure to retail had in fact been falling over the time period because of the expected (and now completed) disposal of SSE energy services.

179. And nor does the evidence justify Ofgem's disregard for the decomposition analysis of National Grid and SSE's beta, which supports a higher equity beta than Ofgem's range. CEPA, writing on Ofgem's behalf, stresses the theoretical validity of the exercise, and admits two interpretations:

   a. the estimation is sufficiently challenging that a "low" weight should be placed on it; or

   b. that the asset beta for GB energy networks has been higher than 0.4 since 2018.[15]

180. CEPA then comes to a final conclusion that "*We consider decomposition analysis relevant evidence, but consider that it at best provides an indication of where Ofgem might consider its point estimate for asset beta should sit within a range relative to the water and European network evidence*".[16] Which, given CEPA's apparent finding that decomposition could support GB energy network asset betas of above 0.4, means Ofgem's advisors have told it that the evidence suggests a point estimate at the top end of its range. Advice which Ofgem has selectively disregarded.

181. Having removed two of the more relevant data points it had, this leaves the analysis Ofgem presents in the draft determinations as depending entirely on a sample of water sector companies.

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[15] CEPA, July 2020, RIIO-2 beta estimation issues, states on both page 7 and page 60.

[16] Op cit, conclusions, stated on both page 7 and 69.

182. The result is a cost of equity goal seek to the levels recently estimated by Ofwat for its PR19 price control, because Ofgem is now also estimating a water sector cost of equity.

183. Ofgem's description of CEPA's findings in its accompanying report on equity beta is also misleading, when it says "*CEPA's report, published alongside this consultation supports an asset beta in the range 0.34 to 0.39.*". In fact CEPA:

a. says that its analysis is "*consistent*" with the draft determination range of 0.34 to 0.39; and

b. gives equal prominence alongside this, in the main conclusion to the report, to a statement that its analysis is "*consistent*" with the SSMD range of 0.35 to 0.40.[17]

184. CEPA also does not appear to support Ofgem's view that energy risk equals water, saying that:

> *Over the long-term, the empirical evidence of GB water network asset betas are most consistent with a range of around 0.34-0.39.* ***This is supportive of Ofgem's SSMD range of 0.35-0.40 for GB energy networks.*** *A slightly lower range might be considered appropriate the more emphasis is placed on the similarities in the water sector regulatory frameworks and the price control building blocks in the two sectors.*
>
> *However, depending on the weight placed on different components of risk we recognise that GB energy networks may be judged riskier than water networks – or at least that the sources of systematic risk are sufficiently different that water networks are an imperfect investment substitute for a pure play energy network in RIIO-2…*[18]

185. Lastly, Ofgem's apparent U-turn on European Energy networks, after more than two years denying their relevance, appears all the more remarkable coming as it does immediately after CEPA's presentation to Ofgem of a different sample of European utilities, that give a lower view of asset beta. A significant part of the difference appears to have been driven by the inclusion of Belgium in the sample, along with Portugal, through Elia and REN. Based on the "long list" estimates presented in CEPA's appendix, the only way to estimate a lower equity beta from European Energy Networks would be to place even more weight on Belgium (through Fluxys).

186. Ofgem should not focus only on *systematic* risk in its assessment of any risk differences with the water sector, since to do so omits *political and regulatory* risk. These represent a material part of the risks faced by investors in networks. Energy networks are exposed to greater regulatory and political risk than water networks since:

a. average energy bills represent a significantly higher cost to the electorate than water bills; and the energy sector is more likely to be in the public eye at any given time.

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[17] CEPA, July 2020, RIIO-2: Beta estimation issues, page 69, "*Overall, we consider that the analysis and evidence presented in this report is consistent with Ofgem's judgement of an appropriate asset beta range at SSMD (0.35-0.40) and draft determinations (0.34-0.39) for the RIIO-2 gas distribution and gas and electricity transmission price controls.*"

[18] CEPA, July 2020, RIIO-2: Beta estimation issues, page 5

b. energy networks are more exposed to this risk any other part of the energy value chain, since they are a natural monopoly.

187. Greater political and public prominence can translate to greater regulatory risk. Based on Ofgem's apparent goal-seek to a lower cost of equity, along with Ofgem's apparent shift to ex post and discretionary regulation, this may be manifesting itself.

FQ6. Is there evidence of a material difference in systematic risk between:

a) RIIO-1 and RIIO-2,

b) distribution and transmission networks,

c) gas transmission and electricity transmission,

d) gas and electricity?

188. Ofgem has asked an open-ended question in its ED2 methodology consultation about any potential reasons for setting a different cost of equity in respect of the electricity distribution sector.

189. We will comment in due course and at present offer no observations on the difference in risk between the sectors covered by the T2 and GD2 draft determinations.

190. Ofgem has not explicitly consulted on its total market return. However, we continue to reiterate that Ofgem has re-interpreted the historical record on inflation as being consistent with CPI rather than RPI, and reduced its range downwards as a consequence.

191. Investors will not perceive this as meeting Ofgem's commitment, early in the RIIO-2 process, of ensuring the switch to CPIH inflation was value neutral.

FQ7. Do you have any views on how we should consider further the gearing impact on beta and cost of capital estimates?

192. Ofgem does not need to consider further the implications for the cost of capital of the "gearing puzzle" highlighted at paragraph 3.70. These questions can be resolved without the need for a change to the standard approach to 'regearing' in finance theory and regulatory practice.

a. The gearing puzzle highlighted by Ofgem in paragraph 3.70 would be resolved in large part by addressing the under-estimate of the risk free rate for CAPM purposes, as demonstrated by Oxera's work for ENA which we address in response to FQ4 above. [19]

b. Any remaining puzzle would be addressed by using spot corporate debt rates in the calculation as well (although Ofgem should still ensure that sectors are remunerated for efficiently incurred embedded debt), also as highlighted in response to FQ4 above.

[19] This finding by Oxera also undermines Ofgem's basis, at paragraph 3.70, for stating that "lower levels of debt beta exacerbate this effect… making us further doubt arguments that we should assume a low debt beta". With the issue resolved by using a properly estimated risk free, this reason to doubt evidence that debt beta is relatively low is gone.

c. Ofgem is incorrect to state, at paragraph 3.72, that "*In its provisional findings, CMA did not need to deal with a large difference between notional and actual gearing, as it assumed that notional gearing aligned with actual gearing estimates.*" The CMA actually re-geared its comparator equity beta estimates using a standard re-gearing formula.[20] This included re-gearing ENAV's equity beta, its only comparator for air traffic control and on which it explicitly placed weight, from zero leverage to NERL's 30% leverage using a standard re-gearing formula, bridging about a third of the capital structure in the process.[21] Other comparator estimates were re-levered over smaller ranges.

FQ8. Do you agree with our interpretation of cross-checks?

193. We do not agree with Ofgem's interpretation of the cross checks.

194. At Ofgem's methodology decision, its cross checks supported a slightly higher cost of equity than its CAPM range, and it adjusted its cost of equity upwards accordingly.

195. To support its new range, Ofgem has had to come up with a revised set of cross checks. Changing cross checks such that they support the underlying assumptions obviously undermines their purpose.

196. Ofgem's new cross checks serve to adjust downwards a CAPM range that is already much lower than Ofgem's previous estimates. The changes in Ofgem's cross checks are tabulated below:

Cross check	May-19	Jul-20
Unadjusted OFTO IRR	5.1%	4.9%
Unadjusted Investment manager TMR	5.5%	5.0%
CAPM (0.75 beta) with investment manager TMR	4.0%	-
CAPM (0.9 beta) with investment manager TMR	-	4.3%
Infrastructure fund: disclosed asset valuation IRR	5.4%	-
Infrastructure funds: implied market IRR	-	4.2%
"Alternative" re-gearing relationship	-	3.2% - 4.1%
Market to Asset Ratios	-	4.2% (or less)

197. There are significant issues with Ofgem's new cross checks:

a. The newly added "alternative" re-gearing relationship cross check:

i) uses Ofgem's low equity beta, TMR and risk free rate as cross checks on themselves;

ii) is based on a re-gearing relationship that is flawed in finance theory terms; and

[20] CMA, July 2020, Final report in the NATS en route plc / CAA regulatory appeal. See page 192 (paragraph 13.95) for confirmation that the CMA followed the same approach to re-gearing equity and asset betas as the parties in the case (i.e. a standard approach).

[21] Op cit. See page 200 (paragraph 13.115) for confirmation that ENAV's actual gearing is zero; page 192 (paragraph 13.96) for confirmation the CMA placed weight on ENAV's asset beta.

iii) departs from the standard re-gearing relationships adopted by the CMA in all its re-determinations of the cost of equity, including the recent NERL re-determination.

b. The newly added market to asset ratios cross check is flawed because it appears it:

i) is based largely on the water sector;

ii) fails to control for financial (cost of debt) outperformance;

iii) is based on a report that is much more cautiously couched than Ofgem recognises, and which also supports values of above 4.2%, and potentially up to 4.8%[22]; and

iv) triple counts the supposed outperformance evidence that Ofgem also uses to support an allowed returns deduction and for setting GD2 cost benchmarks based on a tougher percentile.

c. The updated "un-adjusted investment manager TMR" is skewed downwards by Ofgem's choice of precise data point, rather than by underlying reductions in those forecasts.

198. Once we remove the flawed new cross check, correct the investment professional forecasts, and reflect CEPA's more nuanced conclusions, the result is a range that runs from about 4.2% to 5.8%.

199. Ofgem's cross checks do not support a reduction relative to Ofgem's updated CAPM range. They support an even bigger increase than was made at the sector specific methodology decisions.

200. We offer more detailed comments the various cross checks below.

Ofgem's Overall WACC cross check

201. As set out immediately above, Ofgem's "overall WACC cross check" is in fact not a cross check, because it is fundamentally based on Ofgem's estimates of the risk free rate, total market return, cost of debt, and the particular specification for estimating equity beta that Ofgem has chosen.

202. We have also commented further on this cross check in response to FQ7 above, identifying at least three serious flaws with it.

203. Particularly acute is the fact the CMA did not use the calculations set out on its appendix on gearing in the cost of capital estimates it adopted in the NERL case. It instead applied a standard re-gearing formula to re-gear comparator beta estimates to the notional gearing.[23]

204. The CMA's approach in the NERL case therefore gave no basis whatsoever for Ofgem to use the results in Table 21 as a cross check, or to fail to re-gear between the gearing estimated for United

[22] On page 34, under the heading "*What implications might be drawn by Ofgem from this analysis?*", CEPA says that "*one interpretation*" is that Ofwat's estimate represents an upper limit but CEPA also admits there is still a "*legitimate discussion*" about differences in risk, concluding much more weakly that "*Ofgem's assumptions **at SSMD** are unlikely to lead to a material underestimation of the cost of equity*" (emphasis added; the SSMD value was a 4.8% real cost of equity).

[23] See paragraph 192.c above.

Utilities and Severn Trent, which is as low as 52% in some of the figures stated in Ofgem's table 13, and the 60% notional leverage that Ofgem assumes.

205. At paragraph 3.75, Ofgem also suggests aligning notional gearing with that of comparators. We have two comments on this suggestion.

a. there is no basis for this in the CMA's approach to gearing in the NERL case since the CMA adopted NERL's level of gearing and re-geared comparators to this level.

b. Any time Ofgem makes an assumed reduction in notional gearing it cannot assume re-gearing is costless, because it is not. Ofgem should instead:

i) cover the costs of redeeming early any "notional" embedded debt that is being displaced and would have to be redeemed at full market value; and

ii) cover the costs of issuing the new equity, as it is proposing to do.

Market to asset ratios cross-check

206. Inferences about the cost of equity from market to asset ratios can give a relatively wide range for the cost of equity, making them a relatively loose cross check, in common with the other cross checks that Ofgem has at its disposal.

207. However, Ofgem takes a far stronger interpretation of the evidence than can be justified, and claims "*that an allowed return on equity of 4.2% represents an upper limit for the water sector*". As highlighted above, CEPA's conclusions are much more cautiously couched than Ofgem recognises, and could support values of above 4.2%, and potentially up to 4.8%.[24]

208. The fact Ofgem has over-interpreted the evidence is also reflected in the facts that:

a. The three listed water companies were the only companies fast tracked by Ofwat, with one having been fast tracked at two successive price control reviews; it is reasonable for the market to expect them to achieve significant incentive outperformance.

b. We understand that the debt books of United Utilities and Severn Trent are relatively low cost by comparison to their sector, and so they will outperform. Moreover, CEPA presents data that implies Pennon has an even lower cost of debt. [25]

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[24] On page 34, under the heading "*What implications might be drawn by Ofgem from this analysis?*", CEPA says that "*one interpretation*" is that Ofwat's estimate represents an upper limit but CEPA also admits there is still a "*legitimate discussion*" about differences in risk, concluding much more weakly that "*Ofgem's assumptions **at SSMD** are unlikely to lead to a material underestimation of the cost of equity*" (emphasis added; the SSMD value was a 4.8% real cost of equity).

[25] The headline MAR premia that CEPA presents for Pennon in figure 4.1 implies that Pennon's debt book has a market value close to its book value. If this is the case, then that debt book would be exceptionally low cost. Since the allowed cost of debt includes the average embedded cost of debt across the sector, the debt cost outperformance for such a company would be significant and sustained. We have not tested if the low market to book value premium of Pennon's debt that is implied by CEPA's charts is accurate.

c. Oxera analysis on behalf of the ENA demonstrated that "*under a range of plausible scenarios, the current traded premia can be more than explained without any recourse to an assumption that the actual cost of equity is lower than the regulated allowed base equity return. To the extent that conclusions can be drawn, the analysis is consistent with the conclusion that Ofwat has underestimated the cost of equity*".[26]

209. Lastly, Ofgem's own consultants estimated a significantly higher cost of equity from MAR analysis in 2017; the extent of the decline in Ofgem's view of this cross check is inconsistent with any changes in financial markets since then.

a. In 2017 CEPA published analysis of the Cadent Transaction that gave a range for the RPI linked cost of equity, for an energy network, of 3.1% to 6.3%.[27]

b. Converting this value to a CPI linked estimate gives a range of approximately 4.1% to 7.4%, the bottom of which is notably above Ofgem's proposed cost of equity allowance.

c. CEPA's estimate was reduced by flaws such as assuming too little near term debt outperformance, and CEPA's failure to re-gear the estimated cost of equity.[28]

Investor bids for Offshore Transmission ownership (OFTOs)

210. The decline in equity return on OFTO investments is consistent with investors learning the very low risk nature of the investments. OFTOs have extremely low risk characteristics in comparison to onshore RIIO networks, and can be expected to have a significantly lower cost of capital.[29] The wide difference in risk between OFTOs and onshore networks is illustrated in the table below.

[26] ENA, June 1 2020, Submission to the CMA on the PR19 price determinations, paragraph 4.18

[27] CEPA, July 2017, *Key questions for RIIO-T2 and GD2, Lessons from the sale of National Grid Gas Distribution*

[28] Northern Powergrid, February 2018, *The CEPA paper on the Cadent premium: A critique*, previously submitted to Ofgem.

[29] Since Ofgem has not provided the data or calculations underpinning its results we are unable to verify them.

	OFTO	RIIO	OFTO detail	RIIO detail
Revenue Risk				
Price control reset			25 year clarity of revenues	5 yearly reviews with extensive reset risk
Political			Collateral risk only; invisible to public; not in "returns debate"	High profile visibility - growing political target
Counterparty			Single client - part of National Grid, with regulatory backstop	Energy retailers, with regulatory backstop
Benchmarking			Static revenue streams; no benchmarking	5 yearly reviews with extensive reset risk
Indexation			Indexation to headline inflation only	Growing levels of indexation to data from different sectors
Operating Risk				
Asset condition			Acquire new assets, no ongoing construction	Patchwork of assets in widely varying condition
Environmental			Modern assets with limited footprint	Significant environment exposure from older assets
Decommissioning			Incremental environmental costs recoverable	Legacy environmental decommissioning risk
Public safety			Largely offshore assets, limited onshore footprint	Extensive network in close proximity to public
Employment			Small number of recent hires	1000s of employees on a range of legacy contracts
Force Majeure			Force majeure events covered	Only covered by price control resets
Business Risk				
Growth			Static asset – growth assumptions not relevant	Asset growth assumptions are uncertain
Inflation			RPI inflation protection	CPIH inflation protection
Corporation tax			At risk to changes in corporation tax rate	Neutral to corp. tax but exposed to windfall taxes
Pensions			No legacy pensions	Final salary scheme protected by unique legislation
Financing			Financing can be fixed for duration, removing risk	Major ongoing financing and refinancing programme

211. Ofgem highlights that OFTOs tend to have debt gearing in the region of 85% to 90%. This is not surprising, in light of their low risk characteristics. If the risk generated by this additional financial leverage perfectly offsets their low operational leverage and low exposure to most of the risks faced by onshore RIIO networks, then their headline cost of equity of 7.0% nominal, i.e. *ca.* 4.9% plus CPIH as Ofgem calculates, would be relevant evidence on the cost of equity for onshore networks.

212. We can see no other way to use the data from OFTOs.

Investment manager TMR forecasts

213. Ofgem's update to its investment manager TMR forecasts has significantly reduced the Schroders and Blackrock forecasts. This materially reduces the mean (excluding vanguard and WTW) that the cross check is based on. But these changes should be reversed.

a. Ofgem cannot justify disregarding Schroders latest 30 year horizon total return forecast, in favour of a much lower 10 year value, when Ofgem admits it is "*mindful that a 10-year horizon may be shorter than might otherwise be ideal for RIIO-2 purposes*". Consistency with some other forecasts that are shorter than ideal is not a legitimate reason for this change in methodology. The latest available Schroders 30 year forecast should continue to be used.[30]

b. Ofgem's updated value for Blackrock appears to have reflected a temporary reduction by Blackrock in its 10 year horizon forecast for uncertain reasons. The latest Blackrock capital market assumptions (CMAs) that we obtained upon reviewing the Consultation, which were dated June 2020, give an expected return on UK large cap equity of 7.8% at a 10 year horizon or 7.7% at a 30 year horizon, or 8.8% and 8.7% once a one percentage point uplift is applied to convert to an arithmetic mean.[31] Both of these values are well above Ofgem's stated value for a Blackrock 10 year forecast (plus uplift) of 5.7%.

214. Updating these two values raises the un-adjusted TMR cross check from 5.0% to 5.8%, and also raises the CAPM based on this value (using the externally sourced equity beta) from 4.3% to 5.0%.

Infrastructure funds

215. Ofgem has substantially changed its cross check between sector specific methodology decision and present. At the sector specific methodology decision it used unadjusted infrastructure fund discount rates. It now applies an additional step based on the market valuation of the funds.

216. We can see no reasoning in Ofgem's draft determination to support the removal of Ofgem's original cross check. It is simply different to the new cross check Ofgem has now developed. Therefore Ofgem should continue to include its original cross check based on the unadjusted infrastructure fund discount rates.

FQ9. What is your view on the overall in-the-round assessment of allowed returns to equity? Is our judgement of 3.95% at 60% notional gearing reflective of the combined analysis through Steps 1, 2, and 3?

217. The value Ofgem has calculated is not credible, and is well below the value supported by the evidence.

218. Steps 1 and 2 combined arrive at the same cost of equity estimate, 4.2%, as Ofwat's headline value in its PR19 final determinations, even though Ofgem has used different evidence and under some methodological differences. This is some coincidence.

219. In essence, Ofgem has:

a. Ostensibly gerrymandered a range for beta estimates that is much too low;

[30] i.e. the Schroders 30 year UK TMR forecast that was published in January 2019, at a value of 7.9% (or 8.9% once a 1.0 percentage point uplift for conversion from geometric to arithmetic average is applied).

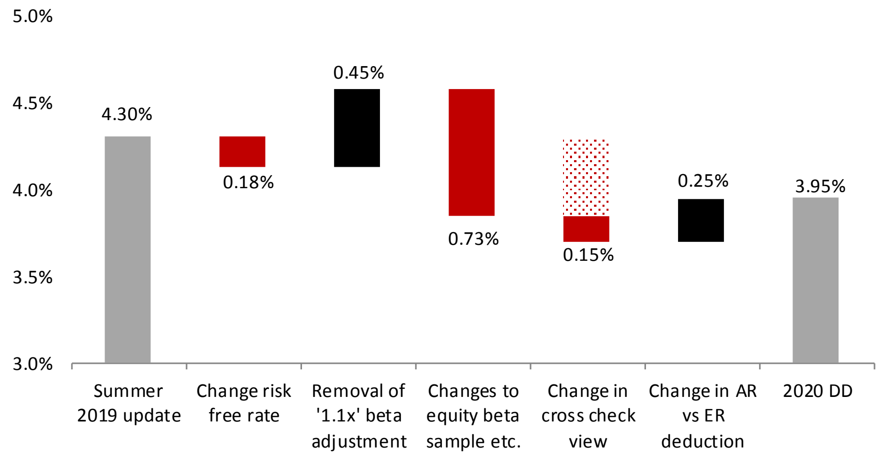
[31] We have separately provided Ofgem with the download data from Blackrock's website.

b. Used flawed or circular "cross checks" to lower this range further still; and

c. Made an unjustified 25bps reduction below Ofgem's own estimate of the cost of equity.

220. We welcome the fact that Ofgem has corrected at least one of the serious issues with its previous CAPM calculations – removing the" 1.1x adjustment" to its equity beta estimates. This adjustment was flawed and led to an equity beta that was not founded in finance theory.

221. Yet rather than now estimating a higher allowed return, Ofgem has estimated one which is lower. The chart below shows how the various parameters have contributed to this.



222. The specific issues with Ofgem's estimate of the cost of equity relate to all three of the red bars in that chart, namely the use of too-low a risk free rate, exclusion of energy networks from the beta estimate, and a new set of cross checks that are deeply flawed. We have addressed these points in response to the questions above.

223. The final issue is the remaining allowed return (AR) versus expected return (ER) deduction, which we address below.

FQ10. What is your view on the expected outperformance estimate of 0.25% at 60% notional gearing? Do you recommend alternative analysis techniques or do you have suggested improvements to the analytical files published alongside this consultation?

a) "AR-ERs database.xlsx"

b) "Residual outperformance.xlsx"

c) "Simple MAR application model.xlsx"

224. Ofgem should remove the expected outperformance adjustment altogether, so it does not set the cost of equity below its estimate of the parameter.

225. We have previously highlighted to Ofgem that the reasons for ensuring that the cost of equity is not too low have been repeatedly articulated by regulators, including the CMA:

Given the uncertainties in cost of capital estimates, we considered the cost of setting an allowed WACC that was too high or too low. If the WACC is set too high then the airports' shareholders *will be over-rewarded and customers will pay more than they should. However, we consider it a necessary cost to airport users of ensuring that there are sufficient incentives to invest, because if the WACC is set too low, there may be underinvestment from BAA or potentially costly financial distress…Given the significance to customers of timely investment at Heathrow and Gatwick, we have given particular weight to the cost of setting the allowed WACC too low. Most importantly, we note that it is difficult for a regulator to reduce the risks of underinvestment within a regulatory period.*[32]

226. Insofar as Ofgem considers timely investment to be important, it should take the same approach.

227. Ofgem has recognised in its draft determinations that it legitimately provides incentives for companies to identify and avoid un-necessary cost in other parts of its price control mechanism; as an engine for ongoing productivity growth and to reveal cost reductions that can lead to significant savings for energy consumers once replicated over the longer term.

228. This legitimate application of incentive regulation does not mean that Ofgem can ignore the incentives that the cost of capital creates to invest. There is in fact a spectrum of company decisions that Ofgem needs to consider:

a. companies need to meet many legal requirements, and cannot simply stop doing so; here Ofgem is under a legal duty to ensure licensees can finance the cost of this activity;

b. there are a range of more discretionary investment decisions where Ofgem uses cost assessment and incentives to ensure efficiency; and

c. amongst these discretionary investment decisions, there are some in particular that Ofgem will keenly want companies to identify and bring forward.

229. It is the last of these three where the incentive to invest is especially important.

230. Setting the parameter as low as Ofgem proposes carries a material risk of setting a marginal cost of equity that is below the true cost of equity. This would be likely to lead to under-investment, and cause additional costs and risks to energy consumers that are likely to outweigh any benefits from underfunding the cost of capital.

231. Ofgem has significantly tightened a wide range of price control parameters for T2 and GD2 when compared to their RIIO-1 equivalents. It does not appear obvious that outperformance can be expected. We can also see additional flaws beyond this in all of Ofgem's approaches to estimating expected outperformance:

a. Approach 1 relies on a large database of regulatory performance. Yet:

i) many of these settlements will bear little resemblance to the controls Ofgem is proposing for T2 and GD2. Cost benchmarks and incentive targets will have been set

[32] Competition Commission, A report on the economic regulation of the London airports companies (Heathrow Airport Ltd and Gatwick Airport Ltd), September 2007, page 49. https://webarchive.nationalarchives.gov.uk/20111202214947/http://www.competition-commission.org.uk/rep_pub/reports/2007/fulltext/532.pdf.

in very different ways, while in some instances the whole regulatory framework will have been different.

ii) The analysis also demonstrates that companies have underperformed their settlement approximately 40% of the time. This evidence therefore demonstrates that it is possible to set price controls that companies do not outperform (contrasting with Ofgem's apparent belief that it is not capable of doing so).

b. Approach 2 adjusts RIIO-1 performance for several differences. However, it omits:

i) significant changes to how cost allowances and incentive targets have been set, generally targeted to make these tougher;

ii) proposals to introduce a large number of uncertainty mechanisms, so as to avoid setting allowances before actual costs are known; and

iii) the proposal to remove the majority of the cost incentive benefit from companies in relation to asset volume efficiencies, where network asset resilience measures apply.[33]

c. Using approach 3, MAR analysis, in this regard is flawed:

i) No attempt is made to control for other factors that are likely to contribute to the MAR of the listed company, such as:

(1) financial outperformance (which could easily be significant, in the current low interest rate environment, for any companies which have had the opportunity to raise significant debt recently).

(2) the fact the water companies in the sample have all been fast tracked by Ofwat, including one that has been fast tracked at two price controls in a row, and so are likely to be expected to perform better than the sector in general.

ii) The water company MAR are not in any case especially relevant to energy; since any expected outperformance would be sector as well as company specific.

iii) The historical transaction MARs predate a significantly tougher regulatory settlement environment that is likely to have reduced any equivalent MAR should the same assets come up for disposal.

iv) The evidence is at least triple counted across the settlement – since as well as being used to justify an AR versus ER deduction - it is used:

[33] We oppose the latter two of these changes on the basis that they will damage energy consumers and be detrimental to consumers in the longer term.

(1) as a cross check to reduce Ofgem's view of the cost of equity at step 2; and

(2) to justify a move to a tougher cost benchmark percentile in GD2.

232. As all investment managers will highlight, past returns of any specific investment are not a guide to future performance. Ofgem should not ignore this; rather than attempting to infer future performance from past returns, Ofgem should scrutinise the settlement that it is actually proposing to settle. Where it identifies allowances or incentives that cannot be justified as appropriate[34], it should tighten the parameter that it believes it has set too loosely.

233. Ofgem has recognised in its assessment of financeability that it has a duty to finance the efficient costs of equity holders.

234. Yet by proposing to set a cost of equity below its own best estimate of the cost of equity (notwithstanding the fact that estimate is too low), Ofgem is *explicitly proposing not to fund the efficient cost of equity*.

FQ11. What is your view on an ex-post adjustment for baseline equity returns? Is there an alternative mechanism or implementation approach that you think could better meet our stated objectives? Do you have specific views on averaging, pooling or suggested simplifications?

235. The proposed ex post adjustment should not be made. Instead, Ofgem should solve the problem it is seeking to address (that there might be outperformance) at its root-cause, through how it sets incentive and cost targets, and remove the allowed returns deduction altogether.

236. The "backstop" ex post adjustment mechanism does not address the issue of setting the allowed return below its estimated value; for example under Ofgem's proposal the gas transmission licensee might go unfunded for its cost of equity because gas *distribution* licensees, operating very different businesses and under a different set of price control arrangements, have outperformed their price controls. Similar examples could arise even within sectors; for instance if Ofgem over-funded some companies, but not others. No form of averaging across companies can protect from this potential outcome.

237. Worse still, the backstop mechanism also has the effect of further damaging already reduced incentives within the price control period, since it introduces a feedback loop whereby worse performance on incentives could contribute to a financial reward at the end of the period.

238. Averaging and pooling will not help the issue:

a. Any companies which form a large part of the average will know their own actions will have a disproportionate impact on the outcome.

[34] Rolling incentives, and the need to encourage continued improvements in performance towards the end of a price control period, can justify setting targets at levels above current levels of performance. In such instances, Ofgem should not tighten targets (or reduce allowed returns), since this would undermine ongoing incentives for improvement and could undermine regulatory commitment (if Ofgem is undoing past explicit or implicit commitments to incentives).

b. If Ofgem chooses an approach to averaging which is not weighted by size it might still end the price control period materially under-funding the actual cost of equity.

239. We do not think these problems are soluble, except by removing the expected returns deduction.

Financeability questions

FQ12. Do you agree with our approach to assessing financeability?

240. We agree with Ofgem that its assessment of financeability must incorporate testing the adequacy of its allowed cost of equity (as well as the cost of debt and all other costs).

241. For the reasons stated in response to the above questions, we do not agree that Ofgem is setting an adequate allowed cost of equity; because its assessment of the range is too low, and because it is proposing to set an allowed cost of equity below its own assessment of the required equity return (thanks to its expected returns deduction).

242. The results of Ofgem's debt credit quality assessment are also made less clear-cut but its decision to allow particular metrics to stray below the thresholds set by rating agencies, and rely on a more qualitative and discretionary assessment. This decision means Ofgem's results are somewhat ambiguous. We have not considered other details of the calculation.

FQ13. Do you agree with our approach to determining notional gearing for each notional company?

243. In response to previous RIIO-2 consultations we have highlighted three steps that Ofgem should take in ensuring financeability: (1) set an adequate cost of equity; (2) reduce gearing if necessary; and (3) adjust capitalisation rates.

244. It therefore seems reasonable to us for Ofgem to determine notional gearing in light of the financial characteristics of the relevant companies or sectors, including their investment requirement profile. In doing so, however, Ofgem must ensure that the costs of re-gearing from its notional starting point are funded, including notional equity issuance costs, and the notional cost of buying back long term debt, to create financial headroom.

FQ14. Do you have any evidence that would suggest we should consider adjusting our notional company financing assumptions due to the impact of COVID-19?

245. We have not developed any specific evidence on the financing effect of COVID-19 at present; although the impact of COVID-19 remains uncertain and we cannot rule out that such evidence will emerge in future.

Corporation tax questions

FQ15. Do you agree with our proposal to pursue Option A?

246. We agree with parts of option A, but we do not think the "additional protections" are necessary.

247. Ofgem has confirmed as part of the draft determinations that "*We compared the adjusted tax liability taken from the companies' latest CT600 forms against the adjusted notional allowance and*

found that on the whole, allowances were broadly in line with payments made to HMRC, over the course of RIIO-1".

248. This means that the proposed "additional protections" are a regulatory solution without a problem to solve; they will generate additional administrative costs for licensees and Ofgem, which will ultimately be borne by energy consumers, as well as reducing the likelihood that companies will identify efficient and legal approaches to managing their tax bills, which will mean that energy consumers have to fund higher tax bills over the longer term. The proposals are therefore not in the interests of energy consumers, and contrary to Ofgem's duties.

FQ16. Do you agree with our proposals to roll forward capital allowance balances and to make allocation and allowance rates Variable Values in the RIIO-2 PCFM?

249. Yes, we agree with this aspect of the proposals.

250. Rolling forward notional tax pools is the correct approach to maintain consistency with the treatment of tax allowances in previous price control periods.

FQ17. Do you agree with the proposed additional protections? In particular:

FQ17a) do you have any views on a materiality threshold for the tax reconciliation? Do you think that the "deadband" used in RIIO-1 is an appropriate threshold to use?

251. We do not support a reconciliation that is undertaken annually, based on an annual RIIO-1 deadband.

252. This would result in a significant additional regulatory burden, both for Ofgem and the companies. With a low annual threshold, companies could easily trigger the review due to factors what will offset each other from year to year.

253. 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 and some consistency with the previous approach. 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.

FQ17b) Do you have any views on our proposals to retain the Tax Trigger and Tax Clawback mechanisms from RIIO-1?

254. We agree with Ofgem's proposal to retain the tax trigger; including the proposal to remove the deadband. If the corporation tax rate has changed it is reasonable to flow this through tax allowances.

255. The tax clawback mechanism has a weaker basis in regulatory principles, since it is likely to distort company funding decisions. Assuming however that it is retained, it is reasonable for Ofgem to propose a "glide path" that will allow companies time to adjust their financing structures.

FQ17c) Do you have any views on the proposed process for the Tax Review?

256. This whole mechanism appears to be a solution to a problem that Ofgem has found does not exist, because Ofgem's analysis concludes that "*on the whole, allowances were broadly in line with payments made to HMRC, over the course of RIIO-1".*

257. Beyond this we see two problems with the proposed process:

    a. the tax review, and prospect of tax clawback, will remove the incentive for licensees to identify legitimate steps that can reduce tax bills.

    b. it gives rise to a risk of disproportionate administrative costs.

258. Removing incentives to identify legitimate tax savings will mean that these are much less likely to be identified and brought to Ofgem's attention. Ofgem will therefore lack information that it could have used, if it knew it, to reduce overall tax allowances, and thus reduce bills to energy consumers. This is against the interests of energy consumers, even though Ofgem has a duty to promote these. Ofgem is instead favouring the interests of the Exchequer; which Ofgem has no duty towards.

259. We have already commented on the risk of excessive frequency of assessment and materiality threshold in our response to FQ17a above. If the review process is operated too frequently, the administrative burden, including the cost of appointing an independent examiner, seems disproportionate for what could be a relatively small amount of money in the scheme of the price control.

260. Lastly, we think there are further practical issues with the relevant process:

    a. although Ofgem has recognised the fact that corporation tax returns are submitted at a lag, it is not clear to us that Ofgem has recognised that tax returns can also be revised at a later date, further extending the potential lags;

    b. those licensees with tax years that do not align to the regulatory year are likely to be exposed to additional burden in preparing reconciliations for individual years, and additional risk that a review could be triggered due to relatively minor tax mismatches.

261. To solve these issues, Ofgem should:

    a. commit to applying a sharing factor, where Ofgem decides to adjust tax allowances in light of the findings of a review, thus ensuring incentives are maintained;

    b. operate the process less frequently than annually, e.g. at close out or every 2-3 years, with a proportionate deadband.

FQ17d) Do you have any views on the proposed board assurance statement?

262. Additional data assurance is not necessary beyond Ofgem's main data assurance policies. Imposing extra administrative requirements like these, with no tangible benefits, simply create extra costs that energy consumers will have to pay in the longer term.

Return adjustment mechanism questions

FQ18. Do you agree with our proposal to introduce a symmetrical RAMs mechanism as described above?

263. Given the introduction of the RAM, the proposal for a symmetrical RAM is sensible.

FQ19. Do you agree with our proposal to introduce a single threshold level of 300 basis points either side of the baseline allowed return on equity?

264. Given the introduction of the RAM, the proposal for a 300bps threshold seems reasonable.

FQ20. Do you have any other comments on our proposals for RAMs in RIIO-2?

265. It is important that, having introduced a RAM as a backstop, Ofgem makes use of it to set strong incentives throughout the rest of the price control.

266. It is not clear that it is taking full advantage of this in the T2 and GD2 draft determinations.

FQ21. Do you agree with our proposal to implement CPIH inflation?

267. We have previously favoured CPI inflation over CPIH inflation, because CPI inflation has hitherto benefited stronger institutional protections, and been more likely to form the basis for any liquid market in CPI inflation linked bonds.

268. Both of these points have weakened recently, for example the UK's exit from the EU is likely to weaken institutional protections afforded to CPI, and the advantages of CPI over CPIH are now less clear cut.

FQ22. Do you agree with our proposals, including the policy alignment for GT and GD, and to recover backlog depreciation for GT RAV additions (2002 to 2021) over 20 years from the start of RIIO-2?

269. We support Ofgem's recognition that flexibility over depreciation policies remains a valid regulatory tool.

FQ23. Do you agree with our proposed assumptions for capitalisation rates?

270. We have not assessed whether the specific assumptions being proposed for particular sectors (or companies) are appropriate and so give no view on this.

271. However we disagree "*with submissions that 'natural' rates of capitalisation are desirable*"[35]. They may be familiar to accountants or to people who use statutory accounts but in a regulatory calculation there is no reason that:

a. the capitalisation rate in a regulatory calculation has to equal the amount of expenditure going into the capital base; or

[35] Ofgem, 2020, T2 and GD2 Draft determinations, finance annex, paragraph 11.5

b. a particular company's accounting treatment should be reflected in regulatory calculations, especially given the range of accounting assumptions open to companies.[36]

272. Indeed, the issues that a regulator must address are very different to those that an accountant deals with, because the:

a. level of the regulatory capitalisation rate affects the balance between existing and future consumers, which might warrant a different approach to a set of accounts; and the

b. way in which regulatory capitalisation rates are set can affect the incentives that companies face when taking decisions between different types of cost.

273. What accounting capitalisation rates do give is a reasonable idea of what proportion of expenditure is going into assets; and if a regulator wants to spread the cost of a company's asset investments over time, then the accounting capitalisation rate will be in the right ballpark.

274. Taking these factors together explains why Ofgem said in its RIIO handbook that:

> *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).*[37]

275. Ofgem previously took the conscious decision to establish a fixed capitalisation rate under RIIO. It explained this was "*intended to equalise the incentives on capex and opex and avoid distorting decision making*".[38] In other words, company decisions on asset investments versus asset light solutions would not affect the RAV treatment of their costs, as part of its totex approach to regulation. This approach also helps to address a concern raised by external stakeholders that companies might favour RAV investment solutions. Under the totex approach, asset light solutions can enter the RAV too, so incentives are equalised.

276. Ofgem is of course free to consult on and change its approach; but in doing so it should have regard to the reasons it decided to set a single fixed capitalisation rate as its standard approach under RIIO.

277. We see no reason that the approach should change. In fact, we think Ofgem should go further:

a. ***Sector benchmark capitalisation rates:*** In sectors where companies operate similar networks, we would propose that Ofgem fixes a single capitalisation rate from the outset, based on a sector benchmark. This might be appropriate, for instance, in the gas

[36] Ofgem recognises this issue in the draft determinations when it says that "*it is difficult to perfectly reflect each company's accounting approach whilst maintaining a consistent cost classification across companies*" (op cit) and also in its RIIO handbook when it says it uses the example of "drawing on the amount of capex like costs submitted in a company's business plans" (RIIO Handbook, para 12.21).

[37] Ofgem. 2010, Handbook for implementing the RIIO model, page 109, para 12.21

[38] Op Cit, page 109, paragraph 12.20

distribution sector. Even if one company favours a capital heavy approach (or takes an accounting approach that leads to a relatively high capitalisation rate), it will not see higher RAV growth thanks to the combination of:

i) benchmarking of capitalisation rates; and

ii) comparative totex benchmarking to establish allowances.

b. ***Alignment of GD approach to capitalisation with all other RIIO sectors:*** In light of the single capitalisation rate applied to up front allowances in most sectors under RIIO, it now seems strange that GD2 will use a distinct capitalisation rate for repex. With the RIIO-1 transition of repex capitalisation now complete, a blended totex capitalisation rate could be applied to the whole totex cost base.

FQ24. For one or more of the aggregations of totex we display in Table 40, should we update rates ex-post to reflect reported outturn proportions for capex and opex?

278. We oppose Ofgem's proposal for a "true-up" of capitalisation rates at the end of period to reflect actual capitalisation rates. This would undermine the totex approach to regulation, since licensees RAV growth would depend on whether they choose capital heavy or capital light solutions for the full range of expenditure decisions they take in the price control period.

279. We can however recognise that the deferral of decisions on many large capital expenditure projects, and uncertainty over whether competition may be used, creates an additional regulatory issue. This issue arises because decisions on those projects (via reopeners) could have a significant effect on the expected capitalisation rate of a particular company or sector, and is most evident in the transmission sectors.

280. But the right answer is not to use actual company capitalisation rates, for the incentive reasons we set out in response to the FQ23. We see multiple options that would be less damaging to incentives and the totex approach to regulation:

a. ***Maintaining the fixed capitalisation rate***, and recognising that a degree of accelerated depreciation carries benefits for energy consumers in terms of avoided future payments of a private sector cost of capital (taking current and future consumers together).

b. ***Setting an alternative (fixed) capitalisation rate for the major project reopener decisions***. Where allowances are provided via these mechanisms, the totex capitalisation rate for the rest of the period could be amended using a blended average of the:

i) capitalisation rate in the main price control; and

ii) capitalisation rate assumption for major additional projects, weighted together according to the size of the allowances in these two respective categories once decisions on reopeners are taken or, where the project is entirely separable from the main cost base, using a specific capitalisation rate for that project[39].

RAV opening balance questions

FQ25. Do you agree with our proposal to use the closing RIIO-1 RAV balances as opening balances for RIIO-2?

281. Yes, we agree with this proposal as the recognised, and expected, approach to transitions between price control periods.

282. Departing from it would represent a significant issue, and potentially undermine the basis of regulation of GB energy networks. The importance of regulatory commitment to RAV as a cornerstone of UK regulation was well illustrated in the Competition Commission's (CC) re-determination on the Pheonix price control, where the CC was highly critical of the Northern Irish Utility Regulator's proposals to retrospectively amend that licensee's Total Regulatory Value (TRV).[40]

283. Ofgem would need to have a specific and well evidenced issue in order even to consider this matter.

FQ26. Do you agree with our proposal to use estimated opening RIIO-2 balances until we have finalised the closing RIIO-1 RAV balances?

284. Yes, this is a reasonable approach and, under the proposals, is only temporary.

FQ27. Do you agree with the three categories of adjustments outlined below?

285. We think one of the categories should be handled in a different way.

286. To the extent the factors are predictable they can be incorporated directly into the RIIO-2 licence (and financial model) so that they flow automatically into revenues. This applies to lagged revenues from incentive mechanisms. The RIIO-1 licence algebra should be allowed to run to its completion, rather than being run through the close out process.

287. The proposals for determining and including MODt, and trueing up the RAV balances, appear reasonable.

FQ28. Do you agree with our approach in using estimated values for closeout adjustments until we are able to close out the RIIO-1 price controls?

288. Yes, this is a reasonable and standard approach, and is only temporary in any case.

[39] This approach appears to be implicit in the reopener specific capitalisation rates set out in Table 40 of the finance annex to the T2 and GD2 draft determinations.

[40] Competition Commission, 2012, Phoenix Natural Gas Limited price determination

Disposal of assets questions

FQ29. Do you agree that proceeds from the disposal of assets during RIIO-2 should be netted-off against totex from the year in which the proceeds occur?

289. Yes, it is sensible to treat asset disposals as negative totex. This:

   a. ensures incentives are equalised between asset investments and asset disposals – so choices to dispose of one asset (potentially replacing it with another) are not distorted;

   b. gives licensees an incentive to maximise the proceeds from disposals, while ensuring the benefits are shared with energy consumers.

FQ30. Do you agree that we should carry out a review where an asset is transferred to a holding company and then subsequently sold to a third party?

290. The electricity distribution licences prohibit the disposal of assets by the licensee without consent (with a limited number of exceptions). This approach could be adopted for the other sectors, if it has not been already.

Time value of money and revenue forecasting questions

FQ31. Do you agree with our proposal to apply one interest rate to revisions to PCFM inputs and charging errors, based on a short-term cost of debt?

291. Our response differs depending on the adjustments in question:

   a. **Ofgem would be wrong to apply this treatment to cost allowance revisions**, if Ofgem does not allow licensees to included forecasts for these values in its charges.[41]

   b. **The proposals seem reasonable for incentives**, on the basis that Ofgem is proposing a package that allows licensees to include forecasts of incentive performance when it sets charges.

We set out our reasoning on each of these points below.

Cost allowance revisions

292. Ofgem would be fundamentally wrong to extend a short term overnight debt interest rate to prior year revisions to cost allowances (assuming that it prevents licensees from including forecasts of these in their allowed revenues).[42]

293. This is not a minor issue. Ofgem's approach to the RIIO-2 controls, deferring decisions on allowances on large swathes of expenditure to subsequent reopeners, gives rise to a very real and additional risk of deferred expenditure allowances.

[41] In response to FQ35 we oppose Ofgem's proposal to fail to include forecasts for reopener outcomes.

[42] It would also be wrong to extend a short term cost of debt treatment to decisions to re-profile expenditure across the period, such as the one imposed by Ofgem at DPCR5. We are not clear if Ofgem's proposals entail this.

294. Ofgem is under a duty to ensure licensees can finance the cost of their activities. It must do so.

a. In circumstances where Ofgem makes retrospective revisions to allowances for expenditure, the appropriate financing rate is the price control cost of capital.

b. Investments have been made and every GB price control recognises that companies incur a cost of capital in funding these investments, including a weight on the cost of equity.[43]

c. Where the return of money from those investments is further delayed by Ofgem's process, this cost of capital is not somehow reduced.[44]

d. Ofgem cannot ignore the cost of equity on a subset of the investments made by licensees.

Incentive revenue revisions

295. For incentive revenues, we understand that Ofgem is proposing to allow licensees to recover a forecast of their performance in the year in question.

296. This would return the price control to the basis on which it operated before RIIO (or at least to the basis in electricity distribution before ED1). Any error in forecasting incentive revenues would flow into over-or under-recovery, and it is reasonable to treat this in the same way as under- and over-recovery for other reasons.

297. It is logical that under-and over recovery has historically been referenced to a bank rate. In principle under- and over-recoveries are akin to the using the price control as a short term banking facility. A short term banking rate therefore ensures licensees face no incentive to use consumers as a financing facility, or detriment where revenues fluctuate. There is also a licence requirement to not over-recover, and the prospect of penalty interest where departures of recoveries from allowed revenues are too great, all designed to limit under- and over- recoveries to those which cannot reasonably be prevented.

298. Ofgem should still however be mindful that, where there are now additional restrictions on licensees in varying their charges within year, or even a year ahead (e.g. as there now is in electricity distribution), revenue forecasting is now a more onerous task for licensees than it has been in the past, and larger departures are now more likely. This could place strain on the logic that has historically supported the use of bank rates for under-and over- recoveries, or on the limits where penalties can apply.

[43] In its report for Ofgem on this issue, CEPA carefully avoids saying that the time value of money is the short term cost of debt. Instead it uses the caveated phrases like "*it may be possible to maintain the net present value of the price control revenues and costs even when using a much lower rate, potentially in line with the short-term cost of debt*." (emphasis added). We will however be unequivocal: the cost of finance for any cost in a price control, regardless of how short the funding time horizon, is above the short term cost of debt.

[44] In fact, where these investments are subject to ex post regulatory review, they are likely to be more exposed to risk than the main price control settlement, and thus face a higher cost of capital. CEPA has not explored this point in its report for Ofgem, as it focusses on the time value of money once certainty of the allowed revenue is achieved (which is not the case for expenditure with an ex post reopener decision by Ofgem).

FQ32. Do you agree with the margin-based approach, and the methodology used to calculate a margin of 110bps?

299. The proposals appear to be appropriate for under-and over-recoveries.

300. As set out in response to FQ33, they are inappropriate where licensees have been required by Ofgem to defer recovery in respect of reopener costs.

FQ33. Do you have any reason why the marginal cost of capital for revisions to PCFM inputs and charging errors should remain distinct from each other, or why WACC may remain a more appropriate time value of money for a particular subset of prior year adjustments?

301. We have responded to this question as part of our response to FQ31.

FQ34. Do you agree with our proposal to include forecasts for most PCFM variable values for the purposes of the AIP?

302. Yes, we do.

303. Our reasoning is set out in more detail in the second part of our response to FQ31.

FQ35. Considering re-openers as set out in these Draft Determinations, do you agree with our proposal to exclude them from any forecasting? If not, please submit specific examples or analysis of the potential materiality of actual spend versus initial allowances.

304. Licensees should be *allowed* to include such forecasts, although they should not be required to. Our reasoning is as follows.

   a. To the extent that the revenue for the reopener would represent a proportion of allowed costs that the licensees considers to be significant (in the context of its financing arrangements), it ought to be able to recover those costs promptly, through forecasts for the outcome of a reopener if necessary.

   b. To the extent a licensee has not yet identified the need for a reopener, or has information available to quantify the cost, it would be unreasonable to require a licensee to provide a forecast. Similarly, where the reopener is relatively small (relative to total baseline allowed costs) the administrative costs associated with developing ‘early’ forecasts might be disproportionate.

305. As set out in response to FQ31 above, if Ofgem does continue a policy of excluding reopener forecasts from allowed revenues, it should certainly ensure it allows the cost of capital on the costs represented by reopeners.

FQ36. Do you agree that additional reporting on executive pay/remuneration and dividend policies will help to improve the legitimacy and transparency of a company's performance under the price control?

306. No, we do not support these additional reporting requirements in respect of executive pay or dividend policies.

307. Ofgem should not require licensees to publish details of executive remuneration.

    a. The hurdle Ofgem must get over before it requires a company to disclose (for publication) someone's personal data which – absent the request from Ofgem – the Company is contractually bound to keep confidential must be very high.

    b. Ofgem is not the appropriate body to determine that this information should be disclosed. Parliament, the Financial Conduct 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 the securities that are listed.

308. 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. 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.

    c. 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.

309. 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.

310. If Ofgem does wish to pursue this further, it could consider whether or not gathering the 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.

311. 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.

312. Ofgem should instead focus on promoting legitimacy through how it explains the role of private sector involvement in energy networks, and how this benefits energy consumers.

Base Revenue definition and ODI cap/collar questions

FQ37. Do you agree with the proposed definition of Base Revenue?

313. The proposed definition would not be appropriate for electricity distribution. We expect this to be addressed through the ED price control process.

FQ38. Do you agree with the proposal to fix the values used for ODI caps and collars at final determinations?

314. Yes, we do. This was the approach taken at ED1.

4. NARMs questions

NARM Q1 Do you agree with our proposals on the scope of work within each of the NARM Funding Categories and on the associated funding arrangements?

315. The scope of the categories themselves appear broadly familiar; and the idea that some activity on the NARMs assets would be outside the scope of the NARMs mechanism, or that some of the very largest projects might have ring-fenced deliverables, is as we would expect.

316. However, we would not agree with the extent to which ring fenced price control deliverables are applied to relatively granular or small areas of cost, and assessed on the basis of whether the company uses the originally planned inputs; this would result in micro-managing the companies in question to take ahead a specific regulatory mandated programme of work. Some of the examples of ring fenced deliverables appear to be at an overly detailed level; for instance specifying particular work on fire suppression systems or air intakes (gas transmission, paragraph 3.10).

317. Lastly, on the detail of the proposals we note that:

a. It is not clear to us what Ofgem means when it says that "*Some other work, where risk mitigation is not the primary driver, may be included [in the main NARMs category, A1] but only where it delivers risk reduction benefits and is not covered by another funding mechanism or a PCD.*" If this means that other types of business as usual activity, that was not included in the original forecasts/targets, then this would appear to introduce an inconsistency between forecasts and targets. However, if the risk impact of this activity has been included in setting targets, this inconsistency would be mitigated.

b. We can also understand that category A1 might ultimately include instances where asset work, that was originally expected to take place for different reasons, might not be required for those original reasons. In these instances there ought to be nothing to prevent the network company from prioritising those assets as part of their asset risk reduction programme. At this point risk mitigation would be the primary driver. The relevant network companies should not at this stage need to provide asset or project specific justification for work on the asset.

NARM Q2 Do you agree the funding adjustment principles and our proposals for applying funding adjustments?

318. No, we do not agree with the proposals for applying funding adjustments. The proposals represent a further step in Ofgem's extension of its role into micro-management of company decisions, including the regulation of the inputs used to meet a requirement (rather than outputs or high level risk deliverables). We do not support this trend since it will reduce incentives for companies to manage their costs, and over the long term will lead to higher costs to the detriment of energy consumers.

319. Ofgem is proposing to reduce the scope of the within period incentive for efficient asset management to an incentive for assets that "*have been delivered more efficiently in terms of unit cost efficiencies*", which it equates to "*genuine efficiencies*".

320. In terms of other cost savings that could be achieved through asset management practice:

a. Volume efficiencies through better targeting or substitution of work will face an incentive that is reduced by 95% (since 95% of the allowances would be clawed back, prior to application of the cost sharing factor).

b. Efficiencies from improved risk modelling or better data will face no incentive at all, because they will be completely neutralised in the measurement of the NARM.

321. We do not support this significant diminution of incentives for good asset management practice (as opposed to incentives for lower-cost procurement) which reflects a trend towards ever greater levels of micro-management and will reduce incentives for companies to manage their cost.

322. Beyond this major point we have a number of more specific points to make.

a. ***Higher administrative costs:*** Over the long term this will lead to higher costs to the detriment of energy consumers. Proposals for detailed end of period assessment and a true up of allowances will also raise the administrative burden for licensees and for Ofgem, which will again ultimately be at the cost of consumers.

b. ***Loss of incentives around consequences of failure:*** Making companies neutral to changes in the consequence of failure will remove the incentive for:

i) effective asset management work to develop more accurate assessments of these consequences; and

ii) companies to carefully consider the effect of their investments on the consequence of failure, and ways that they can reduce the consequence of failure.[45]

c. **Perverse incentives against data cleansing:** Ofgem's statement that "*Any data cleansing above the reasonable levels we would expect from a company that is effectively managing its assets could raise wider concerns and may be subject to a case-by-case investigation and appropriate actions.*" creates an incentive for companies to manage their data cleansing activities to avoid raising concerns, rather than ensuring the data accuracy is improved as quickly as possible.

[45] Some decisions made during asset replacement will affect the consequence of failure, and some investment decisions will specifically be altered to reduce the consequence of failure, e.g. re-routing an asset during replacement. Moreover, some asset investment decisions outside of the NARMs category could affect the consequence of failure within a NARMs category and companies would be discouraged under Ofgem's proposed framework from thinking broadly like this. One example is decisions by DNOs to install fire blankets at link boxes instead of link box replacement, thus materially reducing the consequence of failure; an approach which has saved energy consumers large sums during the ED1 period.

323. We can see that Ofgem may be responding to remove potentially perverse incentives that already existing within the current arrangements. However, we think this already reflects an overly-granular set of arrangements, and that the solution is not to make the arrangements ever more granular.

NARM Q3 Do you agree with our proposed approaches to calculating funding adjustments and to application of penalties?

324. As with our response to question 2: "*The proposals represent a further step in Ofgem's extension of its role into micro-management of company decisions, including the regulation of the inputs used to meet a requirement (rather than outputs or high level risk deliverables). We do not support this trend since it will reduce incentives for companies to manage their costs, and over the long term will lead to higher costs to the detriment of energy consumers.*"

325. There is a danger with the proposed level of funding adjustments would leading network operators to deliver against the originally agreed target without pursuing any improvements to their plan. While Ofgem has indicated that justified efficiencies will not be stripped away, the proposed methodology may lead network operators to believe that the bar for proving these efficiencies may be set too high and the incentive to chase the efficiency is lost, resulting in higher longer term costs to customers.

326. Beyond this:

a. We broadly agree with Ofgem's proposed approaches to calculating funding adjustments and the application of penalties.

b. Ofgem should not use the 'pounds worth of risk removed' from the NARM risk metrics to calibrate penalties. The metrics may not be well correlated with asset renewal needs. The pound values may have little or nothing to do with the allowance that Ofgem provided companies, or the cost of delivering the un-delivered metrics.

NARM Q4 Do you agree with our proposals in regards to requirements for justification cases?

327. We are concerned that Ofgem's requirements for justification will be disproportionate.

328. This will raise the administrative burden for relatively small adjustments, either causing additional costs (as well as the general approach dis-incentivising improvements in asset management that could otherwise benefit energy consumers). A principle of proportionality should instead be adopted to ensure that the administrative burden is not excessive.

329. We can give at least three specific examples:

a. Without the use of a deadband, for example, all NARMs delivery would be subjected to the same level of justification which negates some of the benefits that the NARMs framework can provide. We would encourage the use of a deadband to ensure an element of proportionality is made to the assessment/justification process.

b. Ofgem proposes to limit the main cost efficiency sharing factor to unit cost adjustments (a proposal that, as above, we do not agree with). To operate this it proposes to require companies to provide "*evidence of cost efficiencies achieved for schemes or programmes of work underlying their Baseline Network Risk Outputs, and evidence that these efficiencies have not been offset by higher costs elsewhere".* This therefore appears to require companies to provide evidence of their unit costs on their entire cost base. This is disproportionate.

c. Ofgem seems to propose to subject any changes to their NARM methodology, or parameters, to requirements for justification via an Ofgem review in order to make "appropriate adjustments" [46]; applying this to all changes, rather than more proportionately to "material changes" as is presently the case, will significantly raise the administrative burden. We think that justification for non-intervention risk changes (and associated adjustments) should only be required where the changes are relevant to a company's performance with respect to achieving the NARMs targets.[47]

[46] The Consultation, NARMS annex, Paragraph 4.10

[47] At paragraph 4.21 Ofgem proposes that the company performance report would include "quantification and justification of **material** non-intervention risk changes", therefore it is possible that Ofgem is aligned to our view.

5. ESO questions

330. Below we respond to a small number of questions on the ESO regulatory framework. In providing this focussed response we generally do not repeat the points we made in our response to Ofgem's sector methodology consultation on the ESO.

331. However, we again highlight the general point that the system operation role in electricity distribution (DSO) starts from a very different position to transmission, in particular because:

a. Ofgem started from a point of very unequal incentives in the T1 price control for different types of cost in transmission (e.g. TO cost totex incentives, SO internal cost incentives, SO external cost incentives), whereas in electricity distribution at ED1 the same incentives are applied to virtually all costs (including system operation costs).

b. In electricity distribution there is a far broader and more comparable base of customers and network performance that can be used to set explicitly measured incentives.

332. These factors mean that we would expect a very different approach to regulation of system operation functions as part of the DNO's role in electricity distribution.

ESOQ3 Do you agree we should regulate system restoration costs in a consistent manner to other external balancing costs?

333. We hold the general view that the removal of cost boundaries, and application of equalised incentives across the cost base, is in the interests of energy consumers since it should result in less distorted decisions by companies, and greater cost savings over time.

334. We are not familiar with the cost relationships between the ESO's system restoration (black start) costs and its other external balancing costs, and therefore hold no view on whether this general principle applies to these costs.

ESOQ5. Do you agree that a financial reward or penalty should be determined every two-years, to align with the period over which we set expectations, costs and outputs?

335. We agree that six monthly assessment and banking would be too frequent.

336. Ofgem's proposed incentive scheme already appears to operate on difficult to measure and incentivise areas. This means the scheme will be challenging to administer effectively.

337. If the incentive scheme financial outcomes were to be determined on a six monthly basis:

a. The challenge of assessment would be further magnified.

b. Administrative costs would be increased.

c. Stakeholder fatigue and disengagement would be more likely.

d. The incentive power that could apply in respect of outlier or occasional events (i.e. very good or very poor performance for a short period of time) would be significantly reduced.

338. Running the assessment every two years will however run a heightened risk that recent events will overshadow earlier events. The process of ongoing assessment and feedback will be important. The ESO and Ofgem alike would need to take explicit steps to ensure a balanced view over the entirety of the two years.

ESOQ19. Do you agree with our overall approach to cost regulation for the ESO?

339. The proposals at draft determination stage represent a marked improvement on the proposals at the methodology consultation stage (as we understood them) but still suffer from a weakening of cost incentives relative to the status quo.

340. We highlighted in our methodology consultation response that the move to pass through regulation for the ESO's entire cost base amounted to "*giving up on incentives for the ESO to keep the costs it imposes on energy consumers low*."[48]

341. In terms of the checks and balances Ofgem now proposes:

a. We already agreed in our methodology consultation response with the proposal for potential disallowance of manifestly inefficient costs from pass through, although we noted that this was unlikely to be effective against generalised increases in cost.

b. The proposal to include "value for money" as one of the criteria in the ESO's performance incentive scheme, with explicit reference to comparisons between Ofgem's benchmark costs and actual costs, goes further towards addressing the risk of a lack of direct cost incentives; although there may still be the "*risk that the company focuses primarily on justifying cost to the regulator rather than trying to manage them*".[49]

342. However, without the "engine" of an incentive for the ESO to find and reveal cost efficiencies to Ofgem, the ESO may simply not identify these efficiencies or it may soak them up in other related areas. Moreover, the process of two yearly planned cost base reviews by Ofgem, and the perpetual risk of ex post disallowance where costs are not agreed up front, run the risk of a descent into micro-management.

343. Such micro-management is already becoming apparent in Ofgem's proposals to establish licence requirements to adhere to Ofgem agreed policies on staff remuneration and travel and expenses.[50] If strong cost incentives were in place this type of micro-management would be un-necessary.

[48] See paragraphs 34-36 of our response to the sector specific questions in Ofgem's T2 and GD2 methodology consultation.

[49] Op cit, paragraphs 37-38. In electricity distribution some pass through mechanisms have been paired with an ex post efficiency evaluation process while other costs have been ruled out of totex altogether (e.g. most related party margins).

[50] Paragraph 4.62 of the ESO appendix to the Consultation,

ESOQ21 Do you agree with the method we have taken to set each role-specific cost benchmark, including the proportions of capex and business support allocated to each role?

344. Ofgem highlights that its lack of direct comparators mean a comparative or econometric approach to cost assessment is necessitated. We recognised this would be the case in our sector specific methodology response[51], therefore in general we agree with Ofgem's method of a bottom up assessment of the proposed cost base.

345. We lack the specific insights on the relevant business necessary to provide comments beyond this.

ESOQ25 Is there a better method for setting a debt allowance for the ESO?

346. We cannot offer a "better" method since we are not familiar with the likely financing arrangements and costs of the ESO.

347. However, we do think that aspects of the proposals raise questions, in particular the:

a. negative real cost of debt allowance; alternative approaches, including a nominal approach to the cost of debt, might be warranted in such circumstances.

b. use of an elaborately constructed index, with no apparent real-world check on the actual cost of the ESO, or similar companies, raising floating rate debt; and

c. apparently arbitrary assumption on issuance costs.

ESOQ26 Do you have evidence to suggest the equity allowance should be higher or lower for the ESO?

348. Ofgem's own consultants, CEPA, provided Ofgem with a range of 0.45 to 0.5 for the ESO's asset beta.

349. Ofgem has simply chosen the bottom of this range.

350. This selective application of the evidence by Ofgem to support the lowest possible revenue allowance is unwarranted; and reflects a wider pattern that is evident across the whole of the draft determinations. If Ofgem always selects the lowest possible value, it is unlikely to fulfil its duty to finance the costs of the activities of the relevant licensees.

351. Ofgem has combined this asset beta with its own estimates of other CAPM parameters. We consider that Ofgem's estimates of these other parameters are too low; and have commented on this in our response to Ofgem's finance appendix.

[51] See paragraphs 20-21 of our response to the sector specific questions in Ofgem's T2 and GD2 methodology consultation.

ESOQ31. Do you agree that ESO's NIA funding should be subject to the condition that all projects must involve partnership with other network companies, third party innovators and/or academics?

352. We would welcome the opportunity to work in partnership with the ESO on innovation projects, provided the funding framework is appropriate.

6. GD2 questions

353. In this section we respond to a subset of the questions in Ofgem's GD2 specific annex, in particular the questions on:

a. the vulnerability package and the proposed outputs deadband: GDQ2, 4 and 11

b. cost benchmarking: GDQ26 –GDQ41; and

c. uncertainty mechanisms, including the net zero transition:

Consumer vulnerability and incentive deadband

GDQ2. What are your views on the reporting metrics we have proposed for the consumer vulnerability ODI-R?

354. We support Ofgem's proposed package as we think that a combination of adequate funding, licence obligations and reputational incentives represent an effective package in this area.

355. As we have highlighted previously, distribution network companies will find themselves, reasonably frequently, in the right place at the right time to assist vulnerable consumers at a low marginal cost, for instance helping vulnerable consumers get the assistance they need. Where this happens, they should do so. We think that Ofgem's proposals will be effective in incentivising this.

356. We note that use it or lose it allowances introduce distorting boundaries within the totex cost base and therefore we would typically not encourage their use. However, they do ensure that a certain amount of money is likely to be spent on a particular activity, so where Ofgem considers this to be necessary the benefits might outweigh the costs.

GDQ4 Do you agree with our position to change the FPNES from a PCD to a capped volume driver?

357. We are not familiar with the detailed operation of the fuel poor network extension scheme and so this area of the proposals raises some questions for us.

358. We do not know whether the scheme includes "whole system" tests; but if it does not these should be implemented. It may be possible that, for some fuel poor off gas grid customers, it may be cheaper to offer instead of a gas network connection:

a. an annual subsidy to cover the additional heating costs that result from a lack of gas; or

b. investments to improve home fuel efficiency.

359. This would particularly be the case if there is uncertainty over the longevity of natural gas as a fuel, since deferring network extensions (and the associated investments in natural gas heating systems) would create option value. Since this could result in lower costs to energy consumers overall, or greater assistance to fuel poor consumers, Ofgem should at least confirm whether there are

"hurdles" in the GDN process of identifying candidates that ensure the whole system issues are considered properly.

360. It is also possible that an incentive for GDNs to evaluate these options, and retain a proportion of the cost savings if they can be achieved, might help generate cost savings for energy consumers overall (assuming of course that this incentive is not already in place). For example, if Ofgem structured the funding in a way that would allow this, GDNs could open the funding to competition to see if third parties can deliver overall savings from different solutions before network extensions go ahead.

361. Turning to the question, we are not clear what difference there is between a PCD and a capped volume driver, since Ofgem appears intent on operating PCDs as capped volume drivers (clawing funding back if the specified volume is not achieved). Although we do not support this approach, it is our understanding of Ofgem's proposals.

GDQ11. Do you think a deadband should apply to the [shrinkage] financial incentive? If so, please provide evidence as to how this could be quantified.

362. We can see no reason that a deadband should apply to a financial incentive.

a. The whole point of the arrangement is to create an incentive to optimise performance.

b. A deadband switches off the incentive across a range of performance and thus distorts and weakens the arrangement.

c. If the rationale for a deadband is exposure to external factors (i.e. measurement "noise"), then this noise presumably still exists outside of the deadband. A better response to such uncertainty might be to lower the incentive rate and apply the incentive across a larger range (so the incentive still has the same financial "size", but so the effect of any "noise" is less pronounced).

363. For similar reasons, we also disagree with Ofgem's proposal for a deadband in respect of the GD2 customer satisfaction survey incentive (although there is no consultation question on this). It is distorting and against the interests of energy consumers to give average-performing companies no marginal incentive to improve, but to give a relatively strong incentive to better-performing companies.

Cost Benchmarking questions

GDQ26. Do you agree with our proposal of using a top-down regression model?

364. We support this development as continuing the regulatory trend towards totex regulation – but we do not support the cost drivers, which place much weight on "workload", and therefore are directly controllable by the GDNs.

365. A top-down regression model applied to totex, with exogenous and economically logical cost drivers, is a key component of a true totex model of regulation. Such a model would reward companies that run their businesses in a way so as to minimise their costs, and achieve efficient trade-offs between

different types of cost so as to minimise their total costs, rather than optimise their costs against an Ofgem model (which might involve higher costs to consumers over the long run).

366. The move away from disaggregated modelling, applied to large swathes of the cost base, is also a positive development. Applied in such a way, disaggregated modelling is un-necessary and potentially highly distorting between business models (depending on the approach to benchmarking and cost drivers chosen). However, Ofgem's approach to exclusions from totex, which appears to set a relatively low bar, appears likely to have allowed these distortions to survive.

GDQ27. Do you agree with our proposed approach to benchmarking modelled costs at the 85th percentile?

367. No, we do not agree with the proposed shift to use the 85th percentile as a cost benchmark.

368. This is a departure from regulatory good practice, which Ofgem is under a duty to have regard to.

369. Ofgem attempts to justify this departure, at paragraphs 3.26, by reference to the fact that all GDNs have outperformed their cost allowances to date, having used the 75th percentile at GD1. This is however flawed for at least three reasons.

a. Ofgem's comparison of expenditure to allowances is an apples and pears comparison; because Ofgem set GD1 allowances based partly on the company plans.[52] Ofgem is not repeating this approach at GD2. Therefore outperformance of allowances will not identify whether, and to what extent, the GD1 cost benchmark itself was too low.

b. Ofgem highlights, at paragraph 3.25, that it believes it has significantly improved the quality of its benchmarks at GD2 compared to GD1. Ofgem may be attempting to support a toughening of its benchmarks. It is however less likely that companies can be expected to outperform the better quality benchmarks, and therefore any failures of the GD1 models do not represent a justification for departing from the well-accepted approach of a 75th percentile benchmark.[53]

c. There is likely to be a double count in the price control settlement as a whole, since Ofgem is proposing to use the same evidence of outperformance of allowances in GD1 in support of its proposal to reduce the cost of equity on account of expected outperformance at GD2.

[52] These additional allowances were in fact a "reward" aligned to the level at which Ofgem set the information quality incentive (IQI), as they were calculated as part of it. This element of the IQI could just as well have been specified and allowed as an additional reward value, rather than extra cost allowances, since that could have been mathematically equivalent. The outcome of IQI rewards needs to be separated out, and raw GD1 benchmarks used, in order to allow for a like-for-like comparison of the type Ofgem says it is having regard to.

[53] A like-for-like comparison would entail using the data available at GD1 in the model Ofgem is now using at GD2, and testing how closely the 75th percentile based on this new model would have predicted actual expenditure by the GDNs at GD1. A simpler, though less compelling, test would be to compare the 75th percentile benchmarks on Ofgem's GD1 top down model with actual expenditure (i.e. ignoring the results of Ofgem's GD1 bottom up models, since it is not proposing to use this type of model at GD2). In both cases we would caution any regulator against directly using the results of such comparisons to directly inform future target setting, since this could dis-incentivise future efficiency gains. Nevertheless, the results could still be informative on the broad fit of a cost benchmarking model.

370. Given these issues, Ofgem has not presented the evidence necessary to support its departure from regulatory good practice or its assertion at paragraph 3.29 that its targets are "high but achievable".

GDQ28. Do you agree with our proposed approach to estimating embedded ongoing efficiency and values calculated?

371. We agree in principle that Ofgem should not "double count" between efficiency already included in its benchmarks and any additional efficiency assumption applied on top of this.

372. Since we are a stakeholder outside of the relevant sectors we have not inspected Ofgem's detailed models, and neither are we familiar with the way in which any of the plans were constructed, making it harder for us to draw definitive conclusions. We can however see issues with Ofgem's proposals in this area.

a. Ofgem has failed to take any of several approaches that we expect would have avoided this issue, such as:

i) benchmarking historical costs without ongoing efficiencies, and then rolling these forward with ongoing efficiency assumption (the GD1 approach) or

ii) adjusting the company forecast costs to their underlying level without their stated level of efficiency gains, benchmarking these "base" costs, and then applying Ofgem's ongoing efficiency assumption; or

iii) adjusting the company forecasts from their starting efficiency assumption to Ofgem's proposed efficiency assumption, and then using these benchmarks directly.[54]

b. Even taking Ofgem's starting point, of benchmarked forecasts that include ongoing efficiency, it is not clear that Ofgem will have achieved anything close to its policy intent. Ofgem has set an efficiency benchmark based on a specific company (or companies). It would seem more logical to estimate the efficiency embedded in the benchmarks by reference to the benchmark setting company.

GDQ29. Do you agree with our proposed pre-modelling normalisations?

373. No, we do not agree with Ofgem's pre-modelling adjustments. The adjustments, by their nature, have not been tested against the data. And there appear to be a large number.

374. Our specific comments are as follows:

a. ***Too many costs appear to have been excluded from totex:*** the number of exclusions will undermine some of the benefits of a totex approach, by introducing significant cost boundaries into the cost base. And through this process of exclusions, Ofgem could have distorted its totex results. Examples of exclusions that appear excessive include:

[54] In listing these we have omitted the ED1 approach (broadly speaking benchmarking the company plans including their stated efficiency and using the results directly) since Ofgem has these results to hand and has decided to not use them.

i) the threshold for "large" capex projects, at £0.75m, in fact appears to be relatively low; and

ii) IT and telecoms projects, and cyber costs, could all be catered to by a totex allowance that offers a reasonable "average" level of funding within totex at any one point in time (without trying to follow specific company "ups and downs").

b. ***The sheer volume of claims highlights the "one way bet" nature of these adjustments:*** It appears from Ofgem's appendix on company specific claims that many companies have made these, with Cadent in particular making a large number of requests. This is unsurprising in a process where companies can benefit from what is, in effect, a claim for additional cost allowances that falls outside the business plan incentive (and is "costless").

c. ***We do not think Ofgem has published its assumed regional labour cost differentials:*** Ofgem has set out figures for its regional labour adjustment in millions of pounds, but it has not (as far as we have identified) set out the regional differential in labour costs underlying this. This makes it difficult for us to comment on the results of its analysis.

d. ***All GDNs operate in urban areas and this effect should be recognised:*** Ofgem appears to have made an urbanity adjustment for all activities within the M25. Yet all GDNs will operate at least part of their network in urban areas that give rise to similar issues, in terms of rush hour congestion and additional reinstatement costs. Ofgem should try to account for this offsetting effect if it has any data that would allow it to do so.

Model Selection Consultation Questions

GDQ30. Do you agree with the selected aggregation level, estimation technique and time period for our econometric modelling?

375. As set out in response to GDQ26, we support in general a totex approach to regulation, including benchmarking of costs. Therefore we agree with the totex level of aggregation used.

376. In terms of estimation technique and time period, it is essential that Ofgem uses a rigorous process based on theory and evidence of model fit, rather than other approaches, such as choosing models based on results fitting with perceptions or a desire to set tough benchmarks. We are not familiar enough with Ofgem's process, models or results to comment on whether Ofgem has achieved this.

GDQ31. Do you believe we should take into consideration revised cost information for the remainder of GD1 including 2019-20 (actuals) and 2020-21 (forecast)?

377. We agree, as Ofgem highlights, that the additional year's data might yield additional information, to the extent it differs from company forecasts. We also agree with Ofgem that the latest actuals and forecasts may or may not have been impacted by Covid-19; therefore careful consideration would be needed in using these as to whether atypical costs might be affecting the results, or indeed whether any such unusual cost patterns are likely to endure for some time.

Opex Consultation Questions

GDQ32. Do you agree with our selected cost drivers for Opex?

378. We disagree with any weight placed on workload measures (i.e. the synthetic cost elements of Ofgem's GD2 cost drivers) in Ofgem's totex cost driver, as these are manifestly within GDN control.

379. Inefficiency in workloads will in effect "allow" inefficiency into Ofgem's totex cost allowances for GDN's. This mean's Ofgem's assessed view of opex costs will also be upwards biased where GDNs have inefficient workload strategies.

380. Beyond this, in terms of the cost drivers which are mentioned in the sub-section of the Consultation on opex:

   a. The customer numbers component should be a strongly exogenous cost driver.

   b. We assume the external condition report driver may also be (unless GDNs can influence it through their own proactive and asset replacement work).

   c. MEAV will over the longer term be influenced by GDN decisions therefore appears the weakest constituent – although it is still significantly more exogenous than highly endogenous cost drivers (such as workloads, headcount etc).

GDQ33. What are your views on our proposed approach to the synthetic cost driver for repex?

381. The proposed synthetic cost driver raises significant issues of using company controllable workloads as a cost driver.

382. The synthetic cost driver seems to be based on company workloads, and our expectation is that volumes of activity would typically be controllable by the companies in question. This being the case it would perform poorly against any rigorous assessment of the properties necessary for a cost driver to be used in regulatory benchmarking.

383. It would, by definition, fail to identify any volume inefficiency in historical or forecast practice, even though efficient management of work volumes ought to be a large part of the role of any asset management company. Its use, and failure to effectively challenge inefficient volumes, could therefore create significant additional costs to energy consumers over the longer term.

GDQ34. What are you views on our proposed repex workload adjustments?

384. As stated in response to GDQ33, using workloads as a cost driver raises serious issues for regulatory cost benchmarking. It seems unlikely that the proposed adjustments will fully address these issues.

GDQ35. Where we have disallowed workloads, should we consider making corresponding adjustments to opex costs? If so, how do you think this could be done?

385. It is not clear to us that this would be appropriate. These disallowances in opex costs may already have been achieved through benchmarking of those costs (e.g. due to a lower totex cost driver, as a consequence of Ofgem's adjustments) or through an ongoing efficiency assumption.

Capex Consultation Questions

GDQ36. What are your views on our proposed approach to the synthetic cost driver for capex?

386. Our views in respect of the use of a "synthetic" cost driver, i.e. company volumes as a cost driver, are the same as in response to GDQ33. This has very poor properties since decisions on capex volumes are taken by the companies in question. This is a core function of any asset management company and the efficiency of those decisions should not be excluded from cost assessment.

GDQ37. What are you views on our proposed capex adjustments?

387. Our views are the same as for repex (set out in response to GDQ34 above). Workload adjustments are unlikely to address the problems associated with using company activity volumes as a cost driver.

Non-regression Costs Consultation Question

GDQ38. Do you agree with our assessment of non-regression costs and our proposed adjustments?

388. Ideally we would expect costs to be included within totex where possible. We can however see that, for some very large and unusual costs, it might be necessary to adopt separate assessment. In doing so Ofgem must be mindful of the boundaries it creates within the cost base.

389. We have one specific comment, which is that do not agree with Ofgem's assessment of streetworks costs, for at least three reasons.

a. ***Many new permit schemes have been introduced in some areas during 2019 and 2020:*** We understand that the most pronounced recent increases have taken place in the more Northern and South Western parts of England. Streetworks schemes went live in large parts of the North East, for example, earlier in 2020. Ofgem's approach does not appear to make allowance for these costs, since they are neither in baselines, nor do they appear to be included in the scope of the reopener for new GD2 schemes.

b. ***It is not possible, in practice, for companies to avoid incurring all permit penalties.***

   i) These are small costs incurred during the course of routine activity, often for small violations that most people would consider understandable and impossible to avoid in practice. No licensee will have established an "efficient" benchmark of zero.

   ii) Day to day costs such as these should be funded to an efficient level.

   iii) If the licensee was guilty of persistent or major breaches, the relevant permitting authorities would be likely to prosecute, resulting in large fines. This would be a separate matter.

c. ***Ofgem's approach damages efficiency incentives:*** Setting cost allowances based on each licensee's historical reported costs is damaging to efficiency incentives; it is also likely to result in a distorted assessment as a consequence of any reporting and allocation differences across licensees (and such differences are likely to be present, since elements of reported streetworks costs introduce a cost boundary within other field activities).

390. The first of these three issues could be addressed through careful design of the GD2 streetworks reopener which Ofgem has proposed, by ensuring this allows costs for schemes introduced towards the end of the GD1 period.[55] The second could also be addressed relatively easily. The third would more fundamental changes to Ofgem's assessment.

GDQ39 – 40: questions on technically assessed costs

391. We recognise that some large and discrete costs will necessarily be subject to separate technical assessment. However, we also support the principle that the bar should be relatively high, so that the costs are included in totex wherever possible.

392. We can see, at paragraph 3.148, that Ofgem has sought to absorb many relatively small costs into totex. However, it appears that additional costs could have been included in totex. For example IT and telecoms capex was included in totex as part of the ED1 price review; the efficient level of such costs should average out over time and be largely driven by the scale of the business.

GDQ41. Do you agree with our proposed disaggregation methodology?

393. Yes, we support Ofgem's approach. We proposed this type of weighting approach during Ofgem's early 2020 ED2 cost benchmarking working groups, when some other participants claimed that it was necessary for Ofgem to undertake granular disaggregated benchmarking in order to create a cost disaggregation. We are pleased that Ofgem has now proven this concept, which we assume Ofgem's GD2 team has developed independently of our own suggestion.

[55] If a materiality threshold will be applied for the reopener, then Ofgem should instead ensure it makes allowance for an efficient level of costs in its baselines, including costs associated with schemes that have recently commenced.

Uncertainty mechanism questions

394. We respond below to questions 46 – 50 and 52 – 53 of the Consultation's GD2 appendix. We do not respond to the other questions in this section.

GDQ46. What are your views on our consultation position to address bespoke decarbonisation of heat re-openers through our proposed innovation stimulus, Net Zero and Heat Policy re-opener mechanisms?

395. We agree with Ofgem's position. Bespoke reopeners should not be necessary given the suite of re-openers that Ofgem proposes. This would be true even if Ofgem adopted the "narrow" definition of the net zero reopener that we support.

GDQ47 What are your views on the questions set out in paragraph 4.57 of this document in relation to large hydrogen projects?

396. Paragraph 4.57 raises many interesting detailed questions. Ofgem's proposed policy package of innovation funding, with reopeners for heat policy and net-zero, means it is not necessary to answer these questions today, and we believe they should be addressed through future consultations when the practical examples they must be answered in relation to are clearer.

GDQ48Do you have any other comments in relation to this section?

397. We support innovation projects aimed at fully understanding the cost of hydrogen as a decarbonisation route, in the same way as we support innovation projects to fully understand the cost of electricity as a decarbonisation route, and projects on the cross-over boundary exploring both options as part of a mix.

398. We also support decisions to keep options open, where the country's pathway is not yet clear. If the wrong pathway is identified and taken, then this could render investments stranded (or at least under political pressure due to excessive cost) and this would not be in the interests of energy consumers or investors in networks.

GDQ49What are your views on our proposal to introduce a new domestic connections volume driver?

399. Where there is significant uncertainty over an externally driven volume, it is appropriate to use a volume driver for any costs that cannot be recharged to the users driving the costs.

400. Ofgem's documentation mentions service connection costs. We are unclear why any sole use costs would not be rechargeable to consumers, since this would fail to meet the principle of cost reflectivity. However, to the extent DNOs cannot recover costs directly from the connectees, then the price control should make allowance for these costs.

GDQ50What are your views on our proposal to continue with the large loads re-opener?

401. No, we can't agree with this approach based on the information set out in the Consultation.

402. GDNs should recover the costs of re-enforcement of the existing network, due to the connection of abnormally large loads, from the connectees in question. If a new power station, or distillery, is

driving such large costs, then it should be sent a price signal associated with the full cost of its connection in a particular region. This will help ensure that optimal locations are chosen and that only economically viable projects go ahead, instead of allowing un-viable projects to be cross-subsidised by gas users in general.

403. We do recognise that re-enforcement costs might not all be attributable to a specific connecting party. But the Consultation appears to indicate that the proposal would cover the cost of all re-enforcement.

404. Of course, GDNs should be allowed to recover these costs somehow. So if the issue lies with overly-restrictive connection charging rules that currently prevent cost reflective recovery, then Ofgem still has time to address this as we move into the GD2 period.

GDQ52Do you agree with our proposal to continue with a smart meter rollout re-opener?

405. We can see that an uncertainty mechanism may be appropriate, but we disagree with Ofgem's proposal for an ex post reopener through which to allow costs.

a. We agree there is ongoing uncertainty over the timing and extent of the smart meter rollout, which means that some form of uncertainty mechanism is appropriate.

b. Several years into the mass rollout phase, Ofgem ought to be able to establish an ex ante basis for cost allowances or a volume driver; this would ensure GDNs were exposed to strong incentives to manage their costs in this area.

GDQ53Do you agree with our proposal to continue with a common streetworks re-opener?

406. We agree with the need for a re-opener, but we disagree with Ofgem's proposed design.

a. ***Ongoing uncertainty over lane rental costs necessitates a reopener.*** Should more local authorities introduce lane rental schemes during the GD2 period, this could impose significant additional costs.

b. ***Ofgem must ensure it makes allowance for recently implemented permit schemes.*** As we comment in our response to GDQ38 above, Ofgem's assessment of costs appears to exclude allowances for the large number of permit schemes introduced in large parts of England during 2019 and 2020.

i) It would be feasible for Ofgem to include an upfront allowance for the expected level of these costs, e.g. based on a benchmark estimate of the annual cost per scheme.

ii) If it does not include an upfront allowance, it should not:

(1) prevent GDNs from recovering costs associated with schemes that were not included in their upfront allowances (i.e. late GD1 schemes should be covered by the re-opener, not just GD2 period schemes)

(2) subject the costs to a common materiality threshold under the reopener in respect of these costs, as to do so would deliberately prevent GDNs from recovering costs that have materialised even before the price control is set.

7. Transmission questions

Electricity transmission

ETQ1 Do you agree with our proposals to switch off the incentive in year one of RIIO-ET2 in order to pilot the Quality of Connections survey and develop the baseline targets?

407. In circumstances where a baseline is not available to establish targets ahead of year 1, this is a sensible approach.

ETQ2 Do you have views on the common milestones, target audience and question of overall satisfaction for the Quality of Connections survey incentive provided in Appendix 2?

408. We have one question about the target audience for Ofgem's suite of output incentives in respect of "Meeting the needs of consumers and network users".

409. We can see the emphasis on customer satisfaction through the connection service, the timeliness of the connection service, and also on reliability of the transmission network

410. However, we can see no elements in the suite that provide an incentive in respect of ongoing interactions regarding connections the transmission network. For instance, where specific existing connections necessitate ongoing discussions over arrangements, or where the transmission licensee offers related services (such as leasing land to connectees) there appears to be no mechanism for tracking user satisfaction and incentivising the transmission licensees against this. This is in contrast to the distribution customer satisfaction survey incentives, which include weight on myriad issues through the catch-all general enquiries element (as well as through the unplanned and planned interruptions element of the satisfaction survey).

411. We can see that it may not be possible at this stage to establish an incentive in this area in time for final determinations. However, this timeframe may allow Ofgem to consider whether one should be considered in the longer term.

ETQ4 Do you agree with our proposed LPD mechanisms and do you agree with the criterion that we are proposing to use for our LPD mechanisms?

412. We think the second mechanism warrants additional consideration, while all three mechanisms would be inappropriate unless there is direct evidence of consumer detriment from later delivery.

413. The second proposed mechanism, the milestone approach to allowances, would apply an implicit penalty in respect of late delivery, specifically where licensees have incurred the cost but not met a particular milestone; the licensee would suffer both the cashflow consequences, as well as the unfunded cost of capital in respect of the delayed allowances. Ofgem should evaluate the size of this prospective penalty in various scenarios and test whether it appears appropriate.

414. Where there is no evidence of direct consumer detriment from later delivery of projects, relative to initial plans, these mechanisms would be inappropriate, because consumers do in general derive a benefit from assets being completed as late as possible, through:

a. delays to funding under the sharing factor, which consumers derive a time value of money benefit from;

b. the ongoing option value of later delivery, since the project could still be cancelled if it becomes apparent it is not necessary (gains from which would be shared with consumers); and

c. the assets being installed later, because the newer assets will last for longer.

ETQ8. Do you have any views on our outputs that have not been covered through any of the specific consultation questions set out elsewhere in this chapter? If so, please set them out, making clear which output you are referring to.

415. Ofgem needs to present some evidence to support its proposal for a 15% improvement assumption in its Insulation and Interruption gasses (IIG) leakage incentive.

416. As the proposals have been presented, the 15% assumption seems to have been plucked from thin air. We assume this carries material financial value, compared to using unadjusted target. Ofgem asserts that this "*sets a challenging yet achievable target and reflects stakeholders' expectations of improvement*"[56], yet there is nothing in the draft determinations to evaluate whether it is actually achievable, or whether companies have been funded to meet stakeholder expectations of this level of improvement.

417. We can see there may be reasons for an improvement to be expected, particularly if TOs have been funded during T1 or are being funded during T2 to secure improvements, or if there is an underlying improving trend in performance. But simply assuming a 15% figure with no apparent basis does not meet regulatory best practice or demonstrate transparency, both of which are principles that Ofgem has a duty to have regard to.

ETQ9. Do you have any views on our overall approach to setting totex allowances?

418. We have not assessed the approach in detail but have five high level comments:

a. **Comparators:** We agree with Ofgem's view that indirect costs of distribution operators are unlikely to offer meaningful a comparator for transmission operators due to the significant differences in the underlying activity.

b. **Cost drivers:** Ofgem has used a cost driver for indirect costs that includes measures such as headcount and expenditure levels; which are directly under the control of the relevant companies and mean that any inefficiency in these values will be translated directly into

[56] Electricity transmission appendix to the consultation, paragraph 2.127

additional indirect allowances. Exogenous cost drivers would deliver stronger efficiency incentives, which would warrant accepting regressions with a worse econometric fit.

c. **Incentives:** We recognise that Ofgem lacks comparators for many costs, but applying a ratchet (to the lower of company historical or planned costs) in many areas weakens ongoing incentives to reduce costs and may also damage incentives to reveal efficiencies in company plans.

d. **Aggregated assessment:** we support Ofgem's use of aggregated assessment of indirect costs, as this will avoid introducing distortions into business decisions when there are trade-offs involved between different indirect costs.

e. **Ongoing efficiency:** we have commented on Ofgem's approach to ongoing efficiency in our response to the core document; those comments also apply here.

NGET

419. We comment below on the small number of questions where we can offer views on Ofgem's general regulatory approach, where we have not already offered these views in response to the core document and the Electricity Transmission annex.

420. We have not reviewed NGET's business plan through the lens necessary to offer specific comments on Ofgem's proposals for specific elements of the plan.

NGETQ1 Do you agree that an Environmental Scorecard ODI-F would be in the interests of existing and future consumers?

421. Yes, we do.

422. The scorecard takes a basket of relatively disparate environmental indicators and in effect applies direct economic incentives to each; the incentivisation of these outputs on this basis ought to be in the interests of existing and future consumers (taken together).

423. We can see why Ofgem has considered whether it might be possible to extend this approach to an environmental output delivery incentive to other transmission operators, as mentioned at paragraph 2.19.

NGETQ2 Do you support our proposed changes to NGET's Environmental Scorecard proposal?

424. Yes, we do.

425. The proposed change to the indicator relating to rollout of electric vehicles, to one which recognises reductions in fleet emissions, equalises incentives between different ways of reducing fleet emissions.

426. We also agree with Ofgem's assessment of the relative merits of different ways of establishing incentive rates, as set out at paragraphs 2.17 of the Consultation.

427. We would however also comment that Ofgem's analysis of specific incentive areas has not necessarily recognised the potential effect of government policy interventions. For example, if policy on electric vehicles has already captured their carbon reducing effect in the roll out subsidies, or lower costs such as lower road tax and avoided fuel duty, it may be that the main cost incentive already ensures that companies will factor the social value of abatement into their uptake decisions. If this were the case, then the proposed additional scorecard incentive might not be warranted, since the underlying market failure has already been targeted directly.

NGETQ3 Do you agree with our proposal to reject the Accelerating Low Carbon Connections ODI-F?

428. Yes, we do.

429. In particular we agree with Ofgem's assessment that establishing meaningful connection specific baselines for lead times would be challenging, and also with Ofgem's assessment that the ESO and the user group would lack the tools and appropriate incentives to play a role in verifying these incentive baselines.

NGETQ4 Do you agree with our consultation position to reject the 'RIIO-T2 System Outage Management Proposals to Reduce Constraint Costs'?

430. We are not familiar with all the relevant arrangements in transmission, so cannot comment on any transmission specific barriers or reasons that might create a need for this incentive.

431. Within electricity distribution our established and long-held position has been that we would provide the ESO with any services it reasonably requires, in particular where this would reduce whole system costs. We would expect to provide such services to the ESO as excluded services under the electricity distribution price control (priced for example at cost, including a reasonable economic margin). This would ensure the ESO traded off the costs on an equal footing with those costs it would avoid. Given we are willing to provide such services under this established regulatory framework, we see little need for an additional incentive.

SPT

432. We comment below on the small number of questions where we can offer views on Ofgem's general regulatory approach, where we have not already offered these views in response to the core document and the Electricity Transmission annex.

433. We have not reviewed SPT's business plan through the lens necessary to offer specific comments on Ofgem's proposals for specific elements of the plan.

SPTQ5 Do you agree with our consultation position to reject the "RIIO-T2 System Outage Management Proposals to Reduce Constraint Costs"?

434. Our response to this question is provided in response to NGETQ4 above.

SPTQ7 Do you agree that SPT's bespoke Net Zero Fund should be included in RIIO-ET2?

435. Providing transmission level funding for "*low carbon initiatives with tangible outcomes that benefit vulnerable communities*" appears to significantly overlap with distribution level activity, and the ED1 (and ED2) price controls. Ofgem should assess any overlap and revise its proposals accordingly.

436. Ofgem states that it has considered providing this type of funding to other transmission companies, but that "*we are not proposing to do this in RIIO-2 because we consider the other TOs are not in the same position as SPT, who can leverage from its experience and existing partnerships on the Green Economy Fund, to mobilise the NZF from the start of RIIO-ET2.*" We can see why Ofgem would form the view that this type of funding does not carry synergies with transmission as an activity in general. Transmission companies have no direct connections to or relationship with vulnerable end users from which to leverage an understanding of consumer vulnerability.

437. However, the activity appears likely to carry significant synergies with the activities that Scottish Power Energy Networks (SPEN, as a group) is already incentivised to undertake through the ED1 stakeholder engagement and consumer vulnerability incentive (and by the incentive's successor arrangements in ED2). Indeed, projects that SPEN has funded through the Green Economy Fund that Ofgem references as a reason for providing SPEN this funding have been directly referenced in SPEN's submissions to the ED1 consumer vulnerability and stakeholder engagement incentive, to help justify the rewards that SPEN has received under that incentive.[57]

438. Providing Scottish Power Energy Networks with significant additional transmission price control funding in this area therefore raises further questions.

a. Firstly, if Ofgem thinks consumers will benefit from this arrangement, would they suffer detriment because Ofgem is not making the arrangements available to electricity distributors immediately? If the answer is yes then Ofgem could put the arrangement in in place through ED2, and potentially earlier via ED1 if this is appropriate for all DNOs, rather than just for SPEN.

b. Secondly, if Scottish Power Energy Networks is provided with this bespoke additional funding, will it be given an advantage in the ED1 SECV incentive when the results of its vulnerability programme is compared to other electricity distribution companies? If this is possible Ofgem ought to take steps to "neutralise" the potential effect on the ED1 SECV scores for all electricity distribution companies (otherwise SP will appear relatively better while the others will appear relatively worse as a consequence of the T2 funding).

c. Thirdly, by providing Scotland-only additional funding in this area, is Ofgem creating a post-code lottery in net zero consumer vulnerability activities? This appears to be likely.

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[57] For example, The HALO Kilmarnock, which is listed as a phase 1 projects on the webpages for SPEN's Green Economy fund, is listed on page 8 of SPEN's submission under the 2018/19 ED1 stakeholder engagement and consumer vulnerability incentive

439. If these questions cannot be adequately addressed, then Ofgem should focus on operating and developing on its consumer vulnerability arrangements for electricity distribution, and should not provide transmission level funding.

SHET

440. We have not reviewed SHET's business plan through the lens necessary to offer specific comments on Ofgem's proposals for specific elements of the plan.

441. Our response above, to NGETQ4, also applies to "*SHETQ2. Do you agree with our consultation position to reject the 'RIIO-T2 System Outage Management Proposals to Reduce Constraint Costs'?*"

Gas transmission

442. We have not identified any specific issues in the gas transmission package that we have not commented on through our responses to the Consultation's core document questions or in response to question ETQ9 above (on transmission level cost benchmarking).

443. We have not reviewed NGGT's business plan through the lens necessary to offer specific comments on the majority of Ofgem's proposals for specific elements of the plan. Our views in response to NGETQ2 may however be relevant to NGGTQ9 (on NGGT's proposed environmental incentive).