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Sent by email to: RIIO2@ofgem.gov.uk

Dear Jonathan,

RIIO-2 Sector Specific Methodology

Thank you for the opportunity to respond to the above consultation. This is a non-confidential response on behalf of the Centrica Group.

We welcome the proposals for how the RIIO-2 framework will be applied for the next round of the network price controls. Many of the proposals improve on current arrangements and represent better value for consumers. These improvements should now be confirmed and we believe there is opportunity for development in other areas.

In particular we would highlight:

- Mechanisms to prevent systemic outperformance are an important enhancement. Appropriately calibrated mechanisms preserve the ability of the best-performing networks to earn higher returns while poor performing networks will earn lower returns.
- The approach for estimating the cost of equity better reflects the level of risk associated with investing in networks.
- Flexibility can help defer or avoid investment in costly network assets. We believe the competition models are a step in the right direction, but believe that competition should be run independently of the network companies.
- We welcome the proposals to remove barriers, such as information sharing, preventing whole system solutions being implemented. We believe that:
  - Incentives should go beyond coordination and information sharing, as proposed, to cover delivery of whole system solutions.
  - Significant progress can be made on information sharing and coordination ahead of the RIIO-2 price controls.
- We welcome separate proposals for the Electricity System Operator.

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Mechanisms to prevent systemic outperformance

Mechanisms to ensure returns do not materially deviate from expectations when the price controls are set should be implemented. An appropriately calibrated mechanism will address the observed systemic outperformance across the sectors in RIIO-1 which is, in part, due to factors such as forecasting error and some incentive mechanisms being inappropriately calibrated. Mechanisms to prevent systemic outperformance preserve the ability of the best-performing networks to earn higher returns while poor performing networks will earn lower returns.

Approach to estimating the cost of equity

The proposals seek to deliver price controls that represent a more appropriate balance of risk and reward between consumers and networks. The approach for estimating the cost of equity, including indexation and removing 'aiming up', better reflects the inherently lower risk associated with investing in networks. Placing greater onus on networks, which can act to manage financeability concerns e.g. such as reviewing dividend payments, also reflects a better balance of risk and reward.

Using flexibility to defer or avoid investment

We welcome the intent to reduce the risk of the stranding of new investment. We recognise several factors will affect the future demand for the use of electricity and gas networks. In the context of the Clean Growth Strategy, decisions about the future of heat are due during the RIIO-2 price controls. This means uncertainty will remain when the price controls are set. As such, we welcome the requirement that new investment will be subject to the 'higher hurdles' test. We support the requirement that both 'build' and 'non-build' solutions (such as flexibility) are fully and objectively considered. Similarly, we support the requirement to ensure the timing of network investment is optimised e.g. using flexibility to support network operation until the long-term need for investment is certain.

More broadly, in the Smart Systems and Flexibility Plan, government has recognised flexibility can help defer or avoid investment in costly network assets and plays a key role in the energy system which is becoming increasingly decentralised and decarbonised [1]. In support of government's ambitions for flexibility, the 'early' and 'late' competition models are positive steps. Flexibility markets at the distribution level are an example of 'early' competition. However, networks operating flexibility markets is dependent on networks choosing flexibility to resolve network constraints. If criteria are not well designed, networks' optioneering could rule out flexibility where it is a valid alternative. Concerns also exist about networks running 'late' competitions. It is not appropriate for networks to run competitions, while also participating in competitions, as this undermines the perception of independence in the market. For the benefits of competition to be realised, it is essential independence is embedded within the regulatory framework.

It should be highlighted that the models, particularly the 'early' model, are inherently dependent on information about network constraints and issues being made available to third parties. We

[1] See https://www.ofgem.gov.uk/system/files/docs/2018/10/smart_systems_and_flexibility_plan_progress_update.pdf.

recognise Ofgem stated its expectation that networks should make this information available, in the recent consultation on placing 'whole system' obligations on the networks. This is an area in which significant progress can be made ahead of the RIIO-2 price controls.

The use of competitive methods to procure system management services is another form of competition relevant to the networks sectors, and should be given focus during RIIO-2. This is an area in which the ESO can leverage its unique role in the energy system to deliver consumer value. Significant progress can be made on developing competitive markets for system management services ahead of the RIIO-2 price controls.

Whole system solutions

We welcome the proposals to remove barriers preventing whole system solutions being implemented. A key element needed to allow third parties to contribute to the provision of whole system solutions is the provision of data relating to the size and location of system constraints. This would provide broad investment signals to third parties. This is another area in which significant progress can be made ahead of the RIIO-2 price controls.

Incentives should go beyond coordination and information sharing. Making the relevant information available at the right times does not automatically lead to whole system solutions being implemented – networks may still choose not to participate in delivery. We recommend the networks are given a licence obligation or a financial penalty-only incentive to fully participate in delivery.

The consideration of coordination should be extended to ensure networks and the Electricity System Operator (ESO) also adopt coordinated approaches to engage with third parties. For example, networks and ESO should adopt coordinated approaches for identifying how 'non-build' solutions should be deployed to resolve system issues and for the competitive procurement of flexibility services.

Electricity System Operator proposals

We welcome the separate proposals for the ESO. We believe the 'package' is broadly coherent. The separate price control complements the ESO becoming a legally separate entity within the National Grid group as of April 2019. The shorter price control better accommodates the uncertainty about how its roles and functions may evolve, but care needs to be taken that this does not lead to short-term thinking.

The 'cost pass-through with margin' remuneration model should provide the ESO with greater discretion to invest, even if above baseline allowances. This complements the policy position that the ESO should invest to improve performance and unlock consumer value, to benefit via the evaluative incentive. The setting of a separate price control will provide greater clarity of baseline expectations of the ESO and is an opportunity to reinforce the policy position that the evaluative incentive is meant to reward or penalise performance instead of funding improvements. If clarity is provided that the disallowance mechanism is considered only in extreme circumstances, then the package should give the ESO certainty of revenues and the price control arrangements should allow the ESO to invest in initiatives to deliver additional consumer value.

I hope you find these comments helpful. Answers to the consultation questions are in the attached appendices. Please contact me if you would like to discuss any aspect of our response.

Yours sincerely,

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APPENDIX 1 – Cross Sector Questions

Output categories questions

CSQ1. Do you have any view on our proposed approach for considering the extent to which a successful appeal has consequences, if any, on other components of the price control?

There is not enough detail in the current consultation for us to provide firm views on this. Any review of the appeal process, or the implications of a successful appeal, should be the subject of full and separate consultation.

CSQ2. Do you agree with our proposed three new output categories?

We are comfortable with the new output categories, although the title of the third category "*Deliver an environmentally sustainable network*" could be improved to better reflect its description: "*Network companies must enable the transition towards a smart, flexible, low cost and low carbon energy system for all consumers and network users*".

The title of this output category emphasises only the low carbon aspect of the outcome. We suggest the title could be: "*Facilitate a smart, flexible, low cost and low carbon system*".

CSQ4. Do you agree with our proposed overarching framework for licence obligations, price control deliverables and output delivery incentives?

We believe this framework has the potential to provide greater clarity over what has been funded by, and the outputs expected from, base revenue allowances. However, much will depend on Ofgem's ability to set baseline allowances that are consistent with both the minimum standards set and relevant targets for Output Delivery Incentives (ODIs).

<u>Licence Obligations:</u>
We agree with setting minimum standards through licence obligations. It is also appropriate that the efficient level of funding required for the delivery of minimum standards is included as part of baseline funding.

Where networks have made significant improvements during RIIO-1, it seems sensible that minimum standards should increase to bank these improvements for consumers. However, given that the consequence of failing to meet minimum standards is significant i.e. a breach of licence, it may be appropriate to include a buffer in the minimum standards: by not capturing the full extent of the improvements achieved and funded during RIIO-1. This approach would work in combination with more stretching ODI Targets i.e. baseline funding would implicitly provide allowances that would allow for above minimum standard performance, but stretching ODI targets would return this to consumers through penalties if the network did not maintain/improve performance in RIIO-2.

This approach should make Ofgem's cost benchmarking exercise more straightforward as it would not need to strip out from observed expenditures an amount deemed to be associated with existing delivery above the minimum standards.

Price Control Deliverables (PCDs):

We support the use of PCDs and agree with the proposed approach to funding i.e. upfront funding, with uncertainty mechanisms, where there is confidence work is likely to be required, and an uncertainty mechanism only where investment is less certain.

We agree with the principle that companies should not benefit from delay in delivery or failure to deliver PCDs, including delivery which does not meet a specified standard. There should be a clear methodology to set out what happens if a PCD is not delivered, delivered late, or is delivered to a lower or different specification.

We also agree that the framework should achieve the right balance between encouraging delivery and enabling flexibility. It is not possible to anticipate every possible reason for a change in delivery and so the methodology should be principles-based. It should allow networks to manage output delivery with a good level of regulatory predictability. We believe the following principles should apply:

- There should not be any rewards for over-forecasting.
- The assessment of network outputs/input activity should explicitly consider both efficiency of the investment decision and consumers' best interests i.e. the efficiency test should be from consumers' perspective, not the networks.
- The incentive regime should differentiate between the rewards available for realising genuine efficiency improvements i.e. delivering a specified output at lower cost, and the rewards available due simply to changes in circumstances which mean the investment was not required or could be delivered at significantly lower cost i.e. due to 'good luck'.

Output Delivery Incentives:

We comment on the specific ODIs proposed in our answers to the relevant questions.

We agree that there should be an appropriate blend of financial, reputational and penalty only incentives. We support the proposal to apply financial rewards mainly where the overall cost of the incentive does not exceed the value of improvements to consumers, and where performance improvements are not already funded through the baseline. The CEPA report on RIIO-1 also emphasises the importance of understanding what has been funded through base allowances when designing incentive schemes[2].

[2] "Review of the RIIO framework and RIIO-1 performance"; page 51: https://www.ofgem.gov.uk/system/files/docs/2018/03/cepa_review_of_the_riio_framework_and_riio-1_performance.pdf.

CSQ5. Do you agree with our proposals to introduce dynamic and relative incentives, where appropriate? Are there any additional considerations not captured in our proposed framework which you think we should take into account?

We support these proposals.

The RIIO framework should mimic competition wherever possible and, so, performance should be assessed relative to other networks where possible. The exact approach could vary by incentive scheme. Some should be designed to be at no overall cost. For example, the Broad Measure of Customer Satisfaction (BMCS) should be zero-sum (subject to a minimum standard) since, in a competitive market, it is improvements in customer service relative to competitors that will bring rewards. Under RIIO-1, BMCS is currently expected to give rewards to all network companies, totalling £525m[3] over the RIIO-1 price controls.

In other areas, such as reliability and availability, absolute incentive scheme targets could be used but updated on a rolling basis, or could be reset at certain points during the price control period, to capture revealed performance and ensure that overall rewards do not deviate from a broadly symmetric distribution for too long. This would allow the price control to react to changes in a similar way to a competitive market and would avoid the current situation in the RIIO-ED1 Interruptions Incentive Scheme where targets fixed at the beginning of the price control will result in the networks receiving £647m[4] in rewards for no improvement in performance. A 'backstop' level of performance could also be introduced.

Designing incentives to reward relative performance, either at an overall or individual incentive level, will also manage the issue of information imbalance. This means networks can no longer benefit as a group for any information imbalance and so should focus analytical resource into getting the 'right' solution. Network companies may have differing ideas of what the right solution is, which would create a competitive tension that improves the rigour of the final arrangements. Including a baseline minimum standard, reflecting revealed performance in RIIO-1, would also act as a barrier to networks ceasing to seek improvements.

Dynamic targets should not impact on the behaviour of networks so long as the marginal incentive rate is maintained and caps and collars are not expected to be reached. We also do not see any conflicts between obliging networks to collaborate in some areas (e.g. funded innovation projects), whilst allowing them to compete in other areas of the price control (e.g. zero-sum incentives).

CSQ6. Do you agree with our proposals to allow network operators to propose bespoke outputs, in collaboration with their User Groups/ Customer Challenge Groups?

We agree with this proposal but bespoke outputs should be proposed and considered only as part of the Business Plan process. We are concerned that allowing bespoke outputs to be proposed during the price control could lead to a significant number of proposals by networks, increasing the complexity and resource burden of the price control.

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[3] 2016/17 prices, assuming performance is held at 2016/17 levels

[4] 2012/13 prices, assuming performance is maintained at 2014/5 levels.

Whole systems:
CSQ8. Do you feel we have defined the problem correctly?

We agree that problems with the four factors identified in the consultation may be acting as blockers to the delivery of whole system solutions.

CSQ9. What views do you have on our proposed approach to adopt a narrow focus for whole systems in the RIIO-2 price control, as set out above?

It is reasonable to adopt a narrow focus for whole systems in the first instance. This will allow the mechanisms to be tested and proved in practice before interactions with other non-energy network sectors are considered. We recognise that, in line with the Clean Growth Strategy, government is due to decide on the long-term future of heat in the first half of the 2020s. It may be necessary to consider whether the proposed mechanisms can support the delivery of whole system solutions if the scope needs to be widened during RIIO-2, to support government policy.

CSQ10. Where might there be benefits through adopting a broader scope for some mechanisms? Please provide evidence.

This may depend on government's decisions relating to the decarbonisation of heat. We do not believe there is a need to broaden the scope at this stage.

CSQ11. Do you have reasons and evidence to support or reject any of the possible mechanisms outlined in this chapter? Do you have views on how they should be designed to protect the interests of consumers?

Broadly, the possible mechanisms can remedy the problems identified. Care should be taken to ensure the proposed coordination and information sharing incentive complements existing industry initiatives and mechanisms being progressed to remedy the same problem, such as:

- Network Options Assessment – the ESO has committed to assessing 'build' and 'non-build' solutions across the transmission and distribution networks to meet transmission network needs[5].
- Introduction of licence conditions to support whole system solutions – Ofgem recently consulted on introducing licence conditions to ensure electricity network operators have clarity of Ofgem's expectations regarding[6]:

[5] "Network Development Roadmap - Confirming the direction"; Page 2, https://www.nationalgrideso.com/sites/eso/files/documents/Network%20Development%20Roadmap%20-%20Confirming%20the%20direction%20July%202018.pdf.
[6] "Consultation on licence conditions and Guidance for network operators to support an efficient, coordinated, and economical Whole System"; paragraph 2.2: https://www.ofgem.gov.uk/system/files/docs/2018/12/whole_system_consultation_dec_18.pdf.

- when and how they must coordinate with others to identify the impacts of actions beyond their network boundaries,
    - how licensees should support other parties' decision-making through engagement,
    - provision of appropriate information, and establishing processes to jointly identify whole system solutions.
- Open Networks project – workstreams include elements relating to data sharing and coordination.
- Network Access Policy - sets out the commitment by the TOs to effectively communicate and coordinate (as far as possible) outage planning and to identify ways in which TO actions can help the ESO minimise constraint costs[7]. It is proposed the licence obligation to comply with the Policy will be retained in RIIO-ET2.
- Energy Data Taskforce – was established to improvs data availability and transparency relating to the energy sector, with specific focus on improving data flows to optimise the operation of the energy system[8].

The consideration of coordination should be extended beyond coordination between networks and across sectors. Networks and the ESO should adopt coordinated approaches when engaging with third parties. For example, networks and ESO should adopt coordinated approaches for identifying how 'non-build' solutions should be deployed to resolve system issues and for the competitive procurement of flexibility services.

In isolation, resolving problems relating to information sharing and coordination does not automatically enable the delivery of whole system solutions; networks are required to participate in the delivery. Other mechanisms, such as balancing financial incentives, target commercial arrangements that may act as barriers to networks' participation. None of the proposed mechanisms compel networks to participate in the delivery of whole system solutions. Developing a 'participation' incentive that serves this purpose should be considered. This incentive could take the form of a licence obligation that compels participation or a penalty-only incentive that financially penalises networks that do not participate.

It is proposed that outputs and, by extension, expenditure allowances could be transferred between licences, to balance financial incentives. This approach may be less effective in removing commercial barriers since transferring expenditure allowances away from a network results in reduced growth in the Regulatory Asset Value (RAV). Transferring funding between networks using the 'directly remunerated services' route could be more effective in removing commercial barriers since expenditure used to fund the 'delivery' network to deliver outputs can be added to the RAV of the 'funding' network.

[7] Electricity Transmission annex paragraph 5.13.
[8] Terms of Reference for the Energy Data Taskforce: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/748566/energy-data-taskforce-terms-of-reference.pdf.

CSQ13. Are there obstacles to transferring revenues between networks that disincentivise those networks from using a coordinated solution (please give details and suggest any changes or solutions)?

It is proposed that outputs and, by extension, expenditure allowances could be transferred between licences, to balance financial incentives. This approach may be less effective in removing commercial barriers since transferring expenditure allowances away from a network results in reduced RAV growth. Transferring funding between networks using the 'directly remunerated services' route could be more effective in removing commercial barriers since expenditure used to fund the 'delivery' network to deliver outputs can be added to the RAV of the 'funding' network.

Asset resilience questions:

CSQ19. Do you agree with our proposals to use monetised risk as the primary basis for network companies to justify their investment proposals for their asset management activities?

In principle, we agree with the use of a common measure at a strategic level that provides an overall view of asset health on networks and that captures the potential impact of investment plans on that overall risk. Networks should be required to demonstrate the value of their investment plans. A common measure may also be a useful way of seeking feedback from stakeholders on Business Plans.

We have concerns about the measure being used for the purposes of assessing costs, setting targets and assessing performance, which could lead to unintended consequences. These are:

- The approach may not fully recognise the degree of uncertainty about the long-term need for some assets and could encourage networks to develop aspects of their Business Plans based on an artificial degree of certainty about future need.

- The approach could create tension with elements of the proposals that encourage networks to prudently manage the uncertainty caused by significant policy decisions that are yet to be made. For example, it is proposed to allow GDNs to invest in 'low and no regrets' heat decarbonisation projects because government decisions on the future of heat are due during the RIIO-2 periods. This could cause some incoherence in investment planning.

- The approach could create tension with elements of the proposals that encourage networks to prudently manage the risk of asset stranding. It is unclear how the approach can complement the 'higher hurdles' test in all investment scenarios. As we discuss in our answer to question CSQ40, flexibility services can be used to mitigate against the risk of investment becoming obsolete in the short-term, because the investment was undertaken before there was sufficient certainty of long-term need. There is a risk that the approach could conflict with government policy on the promotion of flexibility and the intent to require networks to fully and objectively consider 'build, and 'non-build' solutions.

- The long-term monetised risk approach could inadvertently create a bias in investment decision-making towards 'lumpy' high cost investment, to deliver the greatest risk benefit over longer periods e.g. 45 years. This would be based on the assumption that the asset(s) will be needed over that time period.

Also, detail should be provided on how delivery relating to those assets that do not fall within the scope of the Network Asset Risk Metric (NARM) will be assessed. Targets should be linked to all asset investment, as a means of holding networks accountable for delivery. For example, targets for fault rates were set for some assets not captured within the scope of the Network Outputs Methodology in the RIIO-ED1 price control[9, 10].

CSQ20. Do you agree with our proposals to define outputs for all sectors using a relative measure of risk?

If the NARM mechanism is implemented, it is appropriate to use a relative measure of risk across all sectors. However, it is unclear why relative measure has a more direct link between allowances and the work required to deliver outputs. The 'Material Changes' concept developed for the DPCR5 close-out can accommodate the impact of extraneous factors on targets. If risk trading between asset categories is maintained, there is, in theory, no constraint on the extent to which the relationship between expenditure allowances to manage risk and risk targets can be broken once allowances have been set, regardless of the measure of risk selected.

CSQ21. Do you agree with our proposals for defining outputs using a long-term measure of the monetised risk benefit delivered through companies' investments?

In principle, we agree with the use of a common measure at a strategic level that provides an overall view of asset health on networks and captures the potential impact of investment plans on that overall risk. However, we believe the proposed approach may mean there is less visibility over the level of benefits consumers would receive over the price control period or beyond, and the level of associated expenditure[11]. Unintended consequences may arise if this approach is adopted.

There are two mains concerns about a long-term measure of the monetised risk being used to set targets. As highlighted in the consultation, there are difficulties in comparing risks within and across sectors. In some sectors, networks have taken different approaches to managing asset health according to risk (e.g. asset types are not common). Across sectors, different approaches to estimating risk exist. These factors could affect the cost assessment process. Additionally, this could result in less robust targets being set because of the insufficient equivalence between overall monetised risk and the allowances required to manage that risk. Using a long-term

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[9] "Consultation on close out methodologies for the DPCR5 Price Control"; paragraph 2.8: https://www.ofgem.gov.uk/sites/default/files/docs/consultation_on_close_out_methodologies_for_the_dpcr5_price_control_final_0.pdf.

[10] "DPCR5 Closeout Methodologies - further changes since informal consultation"; page 1: https://www.ofgem.gov.uk/sites/default/files/docs/dpcr5_closeout_methodologies_followup_letterfinal_2_0.pdf.

[11] Gas Distribution annex paragraph 5.38.

measure of the monetised risk to set targets may constrain Ofgem's ability to robustly challenge performance.

CSQ22. Do you agree with our proposed approach to setting allowances and outputs?

We have concerns about the proposed approach to setting allowances and outputs. It is unclear how robust benchmarking networks' plans can be, given there is, in some instances, insufficient equivalence between overall monetised risk and allowances required to manage that risk. Further, we agree this approach may mean there is less visibility over the level of benefits consumers would receive over the price control period or beyond, and the level of associated expenditure.

CSQ23. Do you have views on the proposed options for the funding of work programme spanning across price control periods?

Option 1 (costs being logged up and considered for funding in the next price control) is appropriate.

CSQ24. Do you have any views on the options and proposals for dealing with deviation of delivery from output targets?

Networks will be expected to engage with their stakeholders on overall asset health and the cost of maintaining those assets when developing their Business Plans. Networks should propose to deliver a degree of asset health that has received stakeholder support. We agree networks should be exposed to the cost of delivery that exceeds what stakeholders supported, unless it can be demonstrated how that over-delivery is in consumers' interests.

We agree networks should not be allowed to keep the cost allowances associated with under-delivery, regardless of whether the under-delivery is justified. Networks should be penalised for under-delivery unless it can be demonstrated how that under-delivery is in consumers' interests. However, it is unclear how the proposed penalty – an amount equivalent to the monetised risk benefit – will be estimated given the insufficient equivalence between overall monetised risk and allowances required to manage that risk.

CSQ25. Do you have any views on the interaction of the NARM mechanism with other funding mechanisms?

We agree the contribution to monetised risk from activities that are funded through other mechanisms and impact monetised risk should be discounted.

CSQ26. Do you have any views on ring-fencing of certain projects and activities with separate funding and PCDs? Do you have any views on the type of project or activity that might be ring-fenced for these purposes?

It is appropriate to treat certain projects or activities separately from the NARM mechanism even if they contribute to monetised risk. Broadly, these should be projects where:

- the main investment driver is not the management of risk in the context of the NARM e.g. network reinforcement, gas distribution 'Repex' programme,
- projects subject to separate funding arrangements e.g. 'high value' projects,
- project that were started in the RIIO-1 period but will be completed during RIIO-2.

Physical security:

CSQ28. Do you agree with maintaining the existing scope of costs that fall under Physical Security, ie costs associated with the PSUP works mandated by government? Please explain your reasons and suggest alternative definitions you believe should be considered.

We agree the existing scope of costs that fall under Physical Security (costs associated with the PSUP works mandated by government) should be maintained. Also, it would be helpful to distinguish between costs that arise because of works mandated by government and other works associated with physical security but are not mandated by government. It should be made explicit that expenditure for the latter category falls within baseline allowances and the networks will be responsible for managing those projects within their allowances.

CSQ29. Do you agree with our proposed approach of ex ante allowances for PSUP works mandated by government? Please explain your reasons and suggest alternative approaches you believe should be considered.

The proposed approach is reasonable.

CSQ30. Do you agree with our proposal to include a reopener mechanism to deal with costs associated with changes in investment required due to government-mandated changes to the PSUP?

We agree a reopener mechanism to deal with costs associated with changes in investment required due to changes in government policy during the price control should be included.

Cyber resilience questions:

CSQ33. Do you agree with our proposed approach of ex ante 'use-it or lose-it' allowances? Please explain your reasons and suggest alternative approaches you believe should be considered.

We do not agree that ex ante 'use-it or lose-it' allowances should be provided. This mechanism not does easily allow for outputs to be adjusted if the need arises. Ex ante allowances can be provided for those networks that submit strategic investment plans by December 2019. There should also be a reopener mechanism, to accommodate changes in outputs, that are not driven by changes in the regulatory and/or risk landscape during RIIO-2, or to allow those networks without ex-ante funding to justify new allowances. These outputs should be treated as Price Control Deliverables.

CSQ34. Do you agree with our proposal to include a re-opener mechanism for cyber resilience costs? Please also provide your views on the design of the re-opener mechanism.

We agree a re-opener mechanism should be included so that allowances can be provided and outputs defined for those networks unable to submit strategic investment plans by December 2019. The re-opener mechanism could also be used to accommodate changes in outputs that driven by changes in the regulatory and/or risk landscape during RIIO-2.

Real price effects questions:

CSQ35. Do you have any views on our proposed factors to consider in deciding on appropriate input price indices? Do you have any evidence justifying the need for RPEs and any initial views on appropriate price indices?

It will be for the companies to justify the need for RPEs in their Business Plan and we will be better placed to offer an opinion after that point.

We are not yet sure, from the consultation, what Ofgem will consider in deciding on appropriate input price indices. However, if the intent is follow the approach and principles taken for RIIO-1, then we are comfortable with this. In particular, we agree that the index must be sufficiently resilient to DNOs' expenditure decisions in order to avoid circularity (this factor is noted by the health regulator when assessing labour costs within the National Health Service[12]). Also, we believe it is important the index can be produced and accessed in a timely manner, in order to support the assessment of RPEs that should form an input into the Annual Iteration Process.

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[12] "A guide to the Market Forces Factor"; page 14: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/300859/A_guide_to_the_Market_Forces_Factor.pdf.

CSQ36. Do you agree with our initial views to retain notional cost structures in RIIO-2, where this is an option?

We agree this is a sensible approach.

CSQ37. Do you agree with our initial views to update allowances for RPEs annually and to include a forecast of RPEs in allowances? Do you have any other comments on the implementation of RPE indexation?

We support the development and implementation of an appropriate indexation mechanism for RPE allowances. The ex-ante approach used in previous price controls is inadequate because of the apparent difficulty in forecasting the RPE index and the lack of recourse in case the forecast turns out to be significantly different from actual input price growth. It has resulted in consumers unnecessarily funding a significant amount of revenue[13] and requires replacing.

We believe RPE indexation will reduce risk for both consumers and networks. With respect to implementation, we believe that:

- Ex-ante allowances should be based on the best information available
- The composite RPE index should be updated annually with the latest available data
- Revenue should be trued-up with a two-year lag

Annual reconciliation theoretically minimises the amounts to be reconciled compared to reconciliations at the end of the price control. By extension, network charging volatility is theoretically minimised, as is the risk of inter-generational charge distortions between current and future consumers. The required revenue true-ups can be accommodated within the Annual Iteration Process, and the proposed two-year lag is consistent with other mechanisms within the price control framework.

Ongoing efficiency questions:

CSQ38. Do you agree with our proposal to use the EU KLEMS dataset to assess UK productivity trends? What other sources of evidence could we use?

We agree this is reasonable.

Managing the risk of asset stranding:

CSQ39. Do you think there is a need for a utilisation incentive at the sectoral level? If so, how do you think the incentive would operate coherently with the proposed RIIO-2 price control framework for that sector?

A utilisation incentive should not be developed. This could lead to perverse outcomes that conflict with government policy goals of reducing energy consumption and improving energy efficiency.

[13] "Review of the RIIO framework and RIIO-1 performance"; page 5.

It also may give networks an incentive to create artificial constraints on some assets to increase the utilisation of other assets. Neither of these outcomes is of benefit to consumers.

CSQ40. Do you have any views on our direction of travel with regard to anticipatory investment?

We support the proposed approach for new assets (standard assets). Smart technology and energy flexibility can bring considerable benefits to consumers, the UK economy and the environment. The 'higher hurdles' test places more onus on networks to demonstrate the investment need and that both 'build' and 'non-build' solutions have been fully and objectively considered.

Flexibility services can be used to mitigate the risk of asset stranding. In a scenario in which future demand is uncertain, flexibility can be used to support network operation until there is certainty of future demand. This reduces the risk of consumers being required to fund 'build' solutions when sufficient demand to justify investment does not materialise. Indeed, flexibility could be a more cost-effective solution in the long-term in some circumstances. Similarly, flexibility can be used to support network operation in a scenario in which there is greater certainty about future demand but the timing is uncertain. Enhanced cost benefit analysis, considering both 'build' and 'non-build' solutions, should be used to reduce the risk of consumer value being lost.

We are unsure of the benefits of the proposal to encourage new high-value highly anticipatory investment. It should be expected that the need for such investment and the associated costs and benefits are robustly assessed ex-ante. Given the 'highly anticipatory' nature of these investments, it is likely that the consumer benefit will take some time to materialise. We would welcome clarity on the timing of the trigger points. However, if the test or 'trigger point' to determine whether to apply the higher or lower level of return is performed too soon after the initial investment, it is likely that the consumer benefit will be based on a forecast that is not materially different to the original assessment (and so likely to show a consumer benefit). There is also a risk that the trigger point assessment inaccurately forecasts the consumer benefit ultimately realised. The closer in time the trigger point is to the initial investment the more likely it is for the assessment to show and consumer. This means the risk of the consumer benefit not be ultimately realised falls mostly on consumers..

CSQ41. What type of projects may be appropriate for a risk-sharing approach?

We are unsure of the benefits of the proposal to encourage new high-value highly anticipatory investment. Depending on the timing of the trigger point assessment, we consider the approach could create an asymmetric risk to the detriment of consumers.

CSQ42. How can we best facilitate risk-sharing approaches for high-value anticipatory investments?

We are unsure of the benefits of the proposal to encourage new high-value highly anticipatory investment. Depending on the timing of the trigger point assessment, we consider the approach could create an asymmetric risk to the detriment of consumers.

CSQ43. How can we guard against network companies proposing risk-sharing arrangements for project they may have undertaken as business as usual?

We are unsure of the benefits of the proposal to encourage new high-value highly anticipatory investment. Depending on the timing of the trigger point assessment, we consider the approach could create an asymmetric risk to the detriment of consumers.

Innovation:
CSQ44. Do you agree with our proposals to encourage more innovation as BAU?

Networks have received approximately £1.3billion since 2010 via the Low Carbon Network Fund (LCNF), Network Innovation Allowance (NIA) and Network Innovation Competition (NIC) to conduct innovation projects. An independent evaluation of the LCNF estimated net benefits of between £800 million and £1.2 billion from the scheme when projects are rolled out by the trialling companies[14]. It also estimated the potential net benefits could be up to a six-fold increase when a GB-wide rollout is factored in. It was noted that "*…there does not appear to be any overarching plan to ensure the direction of future innovation funding aligns with, and supports, the overall GB energy strategy…*"[15]

It is against this backdrop that more effort should be made encourage more innovation as BAU. We consider this to comprise two parts:

- Leveraging innovative techniques developed during the current and previous price controls and implementing those solutions as BAU
- Undertaking innovation projects.

It is necessary those solutions are now fully implemented and baseline allowances should reflect the gains that can be achieved through innovation. We agree networks should undertake innovation projects as BAU. However, it is unclear why BAU innovation should be focussed on operation and maintenance. There should be no barrier to networks pursuing any type of innovation.

[14] "The network innovation review: our consultation proposals"; page 5: https://www.ofgem.gov.uk/system/files/docs/2016/12/innovation_review_consultation_final.pdf.
[15] "In independent evaluation of the LCNF"; page 108: https://www.ofgem.gov.uk/system/files/docs/2016/11/evaluation_of_the_lcnf_0.pdf.

CSQ45. Do you agree with our proposals to remove the IRM for RIIO-2?

We agree the Innovation Rollout Mechanism should be removed.

CSQ46. Do you agree with our proposals to introduce a new network innovation funding pot, in place of the Network Innovation Competition, that will have a sharper focus on strategic energy system transition challenges?

We support the introduction of a new network innovation funding pot with a sharper focus on strategic energy system transition challenges. We agree it is desirable to increase coordination between network innovation projects and wider publicly-funded energy innovation projects. In principle, we agree it could be appropriate to support whole systems projects if they are likely to generate net benefits to network consumers.

It is essential that relevant projects that have been or are currently being progressed are considered within the scope of the strategic energy system transition challenges. For example, significant funding has been provided to the gas distribution companies for projects relating to the future of gas, environment and 'low carbon' (such as trialling hydrogen as an alternative fuel). The new strategic fund should be used to support those projects aimed to resolve genuine knowledge gaps.

CSQ47. Do you have any views on our proposals for raising innovation funds?

Network innovation funds should be treated as residual charges since they do not provide a marginal investment signal. The Targeted Charging Review is investigating how the 'residual' should be recovered from consumers. The BSUoS Task Force has been convened to assess whether BSUoS charges can be made cost-reflective. It may be appropriate to raise RIIO-2 electricity innovation funds via BSUoS Charges. However, we recommend this is considered after the policy decisions relating to network charging have been made.

CSQ48. Do you think there is a continued need for the NIA within RIIO-2? In consultation responses, we would welcome information about what projects NIA may be used to fund, why these could not be funded through totex allowances and what the benefits of these projects would be.

The NIA was intended to fund small-scale research and development projects with low Technology Readiness Levels (TRLs). Further, there are examples of concepts tested via the NIA which have then been trialled on a larger scale, supported by NIC funding.

Generally, we think innovation should be treated as a business-critical activity and setting totex allowances that require networks to innovate would achieve this. However, at this stage, it is not clear whether networks would progress the 'riskier' small-scale research and development projects or projects with longer payback periods but could potentially realise significant consumer value if they were required to assume all the risk.

We agree with the concerns relating to the NIA, including the lack of sharing of learning and uncertainty that some of projects that have been progressed genuinely fall within scope. If the NIA is to be retained, it may be necessary to consider how funding could be better targeted to support small-scale research and development projects, which have been the ‘feedstock’ for the larger projects. This would require stronger governance arrangements. An option may be to make funding available for smaller projects that support the energy system transition challenges. We also believe the NIA arrangements should be strengthened to further enable third party involvement.

Competition questions:
CSQ51. Have we set out an appropriate set of models for both late and early competition to explore further?

An appropriate set of models for both late and early competition to be explored further have been set out.

CSQ60. Do you agree with the criteria we have set out for assessing who should run competitions? Based on these criteria, which institution do you consider is best placed to run early and late competitions?

Based on the evidence presented in the consultation, it is not clear whether the ESO is best-placed to run ‘early’ and ‘late’ competitions. For example, it has not been suggested how the perception of bias can be mitigated, which may materially affect the ESO’s suitability. It may be possible for arrangements to be implemented that sufficiently mitigate the risk of bias.

Though not proposed in the consultation, the suitability of the ESO to run competitions at the distribution level should be considered, on the basis arrangements that sufficiently mitigate the risk of bias can be implemented. There could be greater perception of bias if network companies are required to run competitions in their ‘host’ areas. It is not appropriate for network companies to run competitions to deliver projects while also competing to deliver the same projects. Requiring the ESO to run competitions at the distribution level may be a way of mitigating against the risk of bias. The economies of scale to be derived from the ESO (or another third party) running competitions at the transmission and distribution levels in the electricity system (and potentially for the gas sector) should be considered.

CSQ61. Do you agree with how we have described native competition? Do you agree we should explore the proposals described above to enhance the use of native competition? Are there any other aspects we should consider?

We agree with how native competition, and the application of the various competition models in the context of native competition, has been described. For the benefits of competition to be realised, it is essential independence is embedded within the regulatory framework. It has not been described how the competitive process can be ‘ring-fenced’ and made sufficiently independent from the ‘host’ network. This could affect the effectiveness of both the ‘early’ and ‘late’ competition models to deliver consumer value. For example, networks operating flexibility markets is dependent on networks choosing flexibility to resolve network constraints. If criteria are not well designed, networks’ optioneering could rule out flexibility where it is a valid alternative. Similar concerns exist about networks running ‘late’ competitions. It is not appropriate for networks to run competitions while also participating in competitions.

CSQ62. How do you think competition undertaken by network companies should be incentivised? Is the use of totex the best approach? Will this ensure a level playing field between network and non-network solutions including the deployment of flexibility services?

For the benefits of competition to be realised, it is essential independence is embedded within the regulatory framework. It has not been described how the competitive process can be ‘ring-fenced’ and made sufficiently independent from the ‘host’ network. This could affect the effectiveness of both the ‘early’ and ‘late’ competition models to deliver consumer value. For example, networks operating flexibility markets is dependent on networks choosing flexibility to resolve network constraints. If criteria are not well designed, networks’ optioneering could rule out flexibility where it is a valid alternative. Similar concerns exist about networks running ‘late’ competitions. It is not appropriate for networks to run competitions while also participating in competitions.

CSQ64. Do you think the ESO could have a role to play in facilitating competition in the gas sectors?

The ESO could have a role to play in facilitating competition in the gas sectors. The economies of scale to be derived from the ESO (or another third party) running competitions at the transmission and distribution levels in the electricity system (and potentially for the gas sector) could be beneficial for consumers. However, measures to mitigate the perception of bias would have to be implemented.

Business Plan and totex incentives questions:

CSQ65. What are your views on our proposed approach to establishing a Business Plan incentive?

We believe there should be an incentive to submit high quality Business Plans.

However, we are unsure whether the proposed approach produces a strong enough incentive to submit high quality and ambitious Business Plans. Whilst we support the introduction of a competitive dynamic, our understanding of the mechanism presented would seem to limit the maximum reward pot available for a whole sector to an amount equivalent to around 3% of a single company’s totex allowances. If networks believe a reasonable number of companies are likely to achieve a ‘Good Value’ or ‘Value’ rating then this level of reward pot will dilute potential rewards and the incentive properties will be dulled.

Similarly, a ‘Low Value’ plan, resulting in a penalty of 1% of totex, or a ‘Poor Value’ plan, resulting in a 2% penalty, may not be a sufficiently strong disincentive against submitting an unambitious plan, particularly if networks are confident they can avoid a negative rating on the qualitative assessment of the quality aspect of the plan.

We support a sharper Business Plan incentive, with greater rewards available for those companies with genuinely high-quality plans, and greater penalties for those with relatively poorer quality plans. This should be made a zero-sum incentive with rewards for those networks with higher quality Business Plans paid for by penalties from those with lower quality Business Plans. Transmission companies could be treated as a group for these purposes. A zero-sum incentive will create a more competitive dynamic amongst networks, providing a stronger incentive to deliver the desired level of quality and ambition in Business Plans.

CSQ66. Under the blended sharing factor approach, should the scope of stage 2 evaluation of cost assessment be based on the entire totex or only on cost items that we consider we can baseline with high confidence?

We agree that including the entire totex would be more beneficial in incentivising companies to submit ambitious cost forecasts for more uncertain elements of totex.

CSQ67. What should be the method for categorising cost forecast as High, Medium or Low? Are the indicative boundaries of 1.0 (High to Medium) and 1.04 (Medium to Low) appropriate?

If Ofgem maintain the proposed Business Plan incentive approach, we consider that the expectation should be for companies to include only efficient costs in their Business Plans. The evidence from RIIO-1 is that the break-even points used for the IQI were insufficient to drive the desired level of accuracy. Therefore, we consider the ‘medium to low’ boundary, in particular, should be tightened and should be no higher than the RIIO-ED1 breakeven even point of 1.03.

CSQ68. What should be the range for the Business Plan reward/penalty? Is the range of ±2% of totex equivalent appropriate for incentivising high quality and ambitious Business Plan submissions (e.g. Value or Good Value)?

As set out above, we are unsure whether the proposed approach produces a strong enough incentive to submit high quality and ambitious Business Plans. Our understanding of the mechanism presented would seem to limit the maximum reward pot available for a whole sector to an amount equivalent to around 3% of a single company’s totex allowances. If networks believe a reasonable number of companies will achieve a ‘Good Value’ or ‘Value’ rating then this level of reward pot will dilute potential rewards and the incentive properties will be dulled.

Similarly, a ‘Low Value’ plan, resulting in a penalty of 1% of totex, or a ‘Poor Value’ plan, resulting in a 2% penalty, may not be a sufficiently strong disincentive against submitting an unambitious plan, particularly if networks are confident they can avoid a negative rating on the qualitative assessment of the quality aspect of the plan.

We support a sharper Business Plan incentive, with greater rewards available for those companies with genuinely high-quality plans, and greater penalties for those with relatively poorer quality plans. This should be made a zero-sum incentive with rewards for those networks with higher quality Business Plans paid for by penalties from those with lower quality Business Plans. Transmission companies could be treated as a group for these purposes. A zero-sum incentive will create a more competitive dynamic amongst networks, providing a stronger incentive to deliver the desired level of quality and ambition in Business Plans.

CSQ69. Do you agree with our assessment of the IQI? (If not please provide your reasons). Do you agree with our proposal to remove the IQI?

We accept that it is challenging for Ofgem to form a reliable view of efficient costs that is independent of company Business Plans. So, it is necessary to include a mechanism that encourages networks to 'truth-tell' and submit ambitious Business Plans.

There is also little evidence that IQI has influenced networks to provide their best view of likely expenditure, and so we broadly agree with the assessment provided of IQI with respect to its operation in RIIO-1.

However, in our response to the framework consultation, we stated that we supported improving and simplifying the IQI, with interpolation removed and the differential in rewards/penalties increased for differences in efficiency of plans. We also stated the IQI 'breakeven point' should be set at 100 i.e. a company whose bid matches Ofgem's view of efficient costs, would be able to achieve a return equal to the allowed cost of capital, if it were to spend, over the price control period, the amount it had forecast.

An improved IQI would seem to us to be a 'safer bet' in terms of delivering an incremental improvement relative to RIIO-1 arrangements, with limited down side risk of unintended consequences.

We are not opposed to the proposed Business Plan Incentive, although as currently described it seems to us not to provide a strong truth telling incentive, which could have unintended consequences.

CSQ70. Do you have views on the effectiveness of the blended sharing factors approach and in particular the incentive it provides on companies to submit more rigorous totex submissions?

We agree this approach should encourage companies to provide more compelling justification for their proposals. It is also likely to result in a better allocation of risk between consumers and companies.

CSQ71. Do you agree with our assessment of the blended sharing factor in comparison to the Ofwat cost sharing mechanism? If not, please provide your reasons.

We are comfortable with the proposed approach for the blended sharing factor, and agree with the assessment in comparison to the Ofwat mechanism. Our concern, as set out above, is that cost ambition may not be adequately incentivised in the Business Plan incentive as described.

CSQ72. Considering the blended sharing factor, what are your views on the factors (e.g. predictability, ability to effectively deal with uncertainty) or evidence that could be used to distinguish between costs that can be baselined with high confidence and other costs?

We agree with the factors set out in paragraph 9.44 of the consultation document.

CSQ74. Do you have any views on whether the proposed Business Plan incentive coupled with the blended sharing factor will drive the right behaviours?

We are comfortable with the proposed approach for the blended sharing factor and agree this should encourage companies to provide more compelling justification for their proposals. Our concern is that cost ambition may not be adequately incentivised in the proposed Business Plan incentive.

We would prefer an improved and simplified IQI, with interpolation removed and the differential in rewards/penalties increased for differences in efficiency of plans. The IQI 'breakeven point' should be set at 100 i.e. a company whose bid matches Ofgem's view of efficient costs, would be able to achieve a return equal to the allowed cost of capital, if it were to spend, over the price control period, the amount it had forecast.

We consider an improved IQI would be more certain to deliver incremental improvement over the RIIO-1 arrangements.

CSQ75. What views do you have on our assessment of the sharing factor ranges?

We believe the assessment is robust and so we agree with the 15% - 50% range presented.

CSQ76. Are there any other factors that you think we should take into account in the design of sharing factors?

We have not identified any other factors at this point.

CSQ78. Do you have views on whether adjustments to sharing factor levels after the price control is set are desirable or necessary?

This is not necessary since networks will be able to propose appropriate uncertainty mechanisms and revenue drivers as part of the initial business plan. This should reduce, although we accept not eliminate, the level of uncertainty in the initial allowances. We also do not think it is desirable as it could distort incentives on investment timings.

CSQ79. Under which circumstance do you consider such adjustments should take place?

We prefer for adjustments not to take place.

CSQ80. When do you consider an adjusted sharing factor should be calculated?

If there are to be adjustments, then we agree that these should take place as part of the close out process. This should reduce the impact on incentives during the price control. However, we believe this would have the potential to become a game where networks could argue for either a higher or lower sharing factor to improve their close out position. We think it more likely that networks will make a case for a change in sharing factors than Ofgem, which could make these arrangements asymmetric to the disadvantage of consumers.

RIIO-2 Achieving a reasonable balance questions

CSQ90. Do you agree with our assessment of the measures we have identified to make the price control more accurate?

We agree with the assessment for most of the measures.

Relating to the cashflow floor, we continue to believe that the onus for ensuring financeability should lie with the companies. As discussed under FQ25, with respect to the cashflow floor variants, whilst we prefer Variant 3 over the others, since it is less likely to be triggered, we are concerned about the proposed mechanics. In appendix 5, step one assumes that the shortfall is funded by consumers via additional charges on bills from suppliers. However, if this is through short notice changes to SO charges levied on suppliers, then it is likely that the majority of this cost will be unable to be factored into supplier charges and will therefore instead be a loss of profits for suppliers. Due to competitive pressures, those suppliers that faced this loss are unlikely to recoup it when SO rates reduce again to return the shortfall (unless it was returned in proportion to market share at the time of the initial cash call). Ofgem needs to give full consideration to how such an approach would work for suppliers, particularly with respect to any remaining price caps.

Regarding the Business Plan Incentive, we believe there should be an incentive to submit high quality Business Plans. However, we are unsure whether the proposed approach produces a strong enough incentive to submit high quality and accurate Business Plans. Whilst we support the introduction of a competitive dynamic, our understanding of the mechanism presented would seem to limit the maximum reward pot available for a whole sector to an amount equivalent to around 3% of a single company's totex allowances. If networks believe a reasonable number of companies will achieve a 'Good Value' or 'Value' rating then this level of reward pot will dilute potential rewards and the incentive properties will be dulled. Similarly, a 'Low Value' plan, resulting in a penalty of 1% of totex, or a 'Poor Value' plan, resulting in a 2% penalty, may not be a sufficiently strong disincentive against submitting an unambitious plan, particularly if networks are confident they can avoid a negative rating on the qualitative assessment of the quality aspect of the plan.

CSQ91. Are there other measures we should take to improve the accuracy of the price control?

For the cashflow floor, it may be worth exploring whether the shortfall could instead be paid for by the other network companies themselves with each network then able to increase use of system charges using normal notice periods to recover the costs from suppliers (and ultimately consumers). Placing the onus onto network companies who can be certain to recoup the cost should result in less risk overall than placing the onus onto supply companies who are unlikely to recoup the cost.

We also support a sharper Business Plan incentive, with greater rewards available for those companies with genuinely high-quality plans, and greater penalties for those with relatively poorer quality plans. This should be made a zero-sum incentive with rewards for those networks with higher quality Business Plans paid for by penalties from those with lower quality Business Plans. Transmission companies could be treated as a group for these purposes.

CSQ93. Do you agree with our consideration of the risks facing these companies? Do you think the measures we are proposing will mitigate these risks? Does the expected level of return indicated by our proposals reflect these risks?

We agree that networks are relatively low risk. The level of risk is reduced by the measures introduced in these proposals compared to current arrangements. These include increased use of indexation and return adjustment mechanisms. We note that the assessment of the appropriate cost of equity does not take account for these measures reducing risk and so this structural reduction in risk is not captured.

We think the beta assumptions are closer to the true value of beta for energy networks in Great Britain. While a significant reduction in beta will enhance the legitimacy and fairness of the price controls, we also think there is evidence that an even lower range for notional equity betas would be justified. We provide details on this in our answer to FQ15.

CSQ94. Have we achieved a reasonable balance with our proposals in seeking to achieve an accurate price control with return adjustment mechanisms only being used as a failsafe? Should we instead have a simpler price control and put more reliance on return adjustment mechanisms?

We believe that a tighter range for the return adjustment mechanisms is required to achieve a reasonable balance. The improvements proposed in this consultation should mean systemic outperformance is less likely and, if it occurs, should be to a lesser scale. This means that the level of outperformance required to demonstrate a systemic problem is lower than under current arrangements. The proposed allowed level of outperformance, of 3%, before return adjustment mechanisms take effect is comparable to current RIIO1 levels of outperformance. This indicates it is too wide for a RIIO2 price control that is expected to be more accurate.

It would not be preferable to have a simpler price control. It is important that high-performing networks are able to earn returns reflecting this performance. A simpler price control would risk the ability to differentiate between different networks.

CSQ95. Have we achieved a reasonable balance in our proposals in considering return adjustment mechanisms alongside the expected-allowed return wedge? Should we instead only rely on one mechanism? What additional value would this bring?

Whilst the expected-allowed return wedge and RAMs proposals have come about from the same underlying issue (systemic outperformance), they are trying to achieve different things and so should be considered separately. The expected-allowed return wedge is directly addressing an expectation of a level of outperformance. The RAMs are a failsafe mechanism if something goes wrong, generating either systemic outperformance of systemic underperformance – this is demonstrated by the symmetric nature of the RAMs. The RAMs are required regardless of the level of expected-allowed return. Potentially, there may be some interaction around the expected-allowed return wedge and where the RAMs range is centred. If a 0.5% outperformance is expected then this may not be an indicator of any failing. This means the symmetric range could be centred around the cost of equity with the expected-allowed wedge being stripped out i.e. a range that would appear asymmetric around the cost of equity.

CSQ97. Are we proposing a methodology that allows us to achieve a reasonable balance between the interests of different consumer groups, including between the generality of consumer and those groups that are poorly served/most vulnerable? Are we missing any group?

We agree with Ofgem's regulatory stance to avoid significant cross-subsidy. Targeted company action to support consumers should be where the networks companies are best placed to deliver that support. Various initiatives are already funded through consumer bills. Funding through network charges is not a transparent method and so should only be used where no suitable alternatives exist.

CSQ98. Are we proposing a methodology that allows us to achieve a reasonable balance between the interests of existing and future consumers?

We remain of the view that economic asset lives should be broadly reflective of their actual useful lives. Robust justification would be required to move away from this.

Preliminary impact assessment questions

CSQ99. What are your views on the approach we are proposing for assessing impact of our RIIO-2 proposals?

The assessment is generally qualitative in nature. This will often be appropriate. Where there is not robust data, or data is open in interpretation, then this a transparent approach as it allows assumptions to be properly explored. Generating quantitative analysis, when based on subjective assumptions, would be far less transparent and rigorous. Assessing companies' response to the changes in incentives structure and levels is an example where a qualitative assessment is likely to appropriate due to the assumptions needed to model responses.

However, where it is possible to provide a reliable quantification it should be done so. The impact on consumer bills from RPI to CPIH should be quantified, for example. This is likely to have a significant impact on consumer bills in RIIO-2 and so transparency is important.

CSQ101. What are your views on the uncertainties we have identified for the purpose of this assessment

We do not believe performance in the last few years of RIIO-1 are of great significance. The proposals are mostly justified without reference to RIIO-1. Any implication that performance in the later years of RIIO-1 could influence the RIIO-2 settlement complicates the incentives the network companies have in RIIO-1.

Ofgem's clarity about linking incentives closer to their cost and risk of delivery is welcome. This should form part of a wider discussion about the purpose of incentives. We would expect this to be part of the further engagement on the effect of incentives on behaviour that Ofgem is planning.

APPENDIX 2 - Finance questions

Cost of debt questions:

FQ1. Do you support our proposal to retain full indexation as the methodology for setting cost of debt allowances?

We believe the approach that would deliver best value for consumers would be one which provided a fixed allowance for efficiently incurred existing debt plus indexation for new debt only. Separating the treatment of efficient embedded and future debt could result in the construction of a shorter trailing average index for future debt that will more closely reflect prevailing market conditions. This would complement the incentive on companies to obtain efficient financing and would ensure consumers do not pay more than efficient future costs.

It should not be assumed actual embedded debt costs are efficient and we would expect a thorough review to identify any individual instances of inefficient financing decisions. Companies should not be protected from the consequences of inefficient financing decisions relating to embedded debt.

We do, however, recognise the challenges associated with assessing the efficiency of embedded debt costs and so whilst we remain concerned that full indexation could weaken the incentive on companies to obtain efficient financing relative to our preferred approach, we are also cautiously comfortable with the proposal to retain full indexation, subject to our concerns set in more detail in answer to question FQ3 below.

We agree with the decision to rule out full pass through of actual debt costs.

FQ2. Do you agree with our proposal to not share debt out-or-under performance within each year?

We believe there is a link with the extent to which Ofgem may allow company-specific adjustments, which result in a higher cost of debt allowance relative to the value derived under the indexation methodology. Our concerns are set out in detail in our answer to question FQ3 below, but we consider that any company-specific adjustment to increase the allowed cost of debt above the indexed value could also be viewed as an explicit sharing of under-performance. Without corresponding adjustments for companies for whom the indexed value would be viewed as generous, this would result in an asymmetric and higher cost outcome for consumers. A sharing mechanism could be one way to ensure more symmetric outcomes for consumers. We note that at a sectoral level, for gas distribution and transmission, the level of outperformance of the cost of debt allowance in RIIO-1 is expected to add c. £1.1bn[16] to the networks' returns.

[16] Source: Supporting data file to regulatory financial performance annex to RIIO-1 2017/18 annual report

FQ3. Do you have any views on the next steps outlined in Finance annex paragraphs 2.22 to 2.25 for assessing the appropriateness of expected cost of debt allowances for full indexation?

We agree that indexation of the cost of debt should consider whether an adjustment is required to reflect the observed 'halo effect' – networks being able to outperform the index due to the fundamental nature of regulated utilities. The CEPA review recognised an adjustment to the index value is justified where the rationale for this adjustment can be explained[17] and also referenced Ofwat's PR19 final methodology which involves a downwards adjustment of 15bps to the iBoxx 10yr+ indices to adjust for the outperformance in the sector.

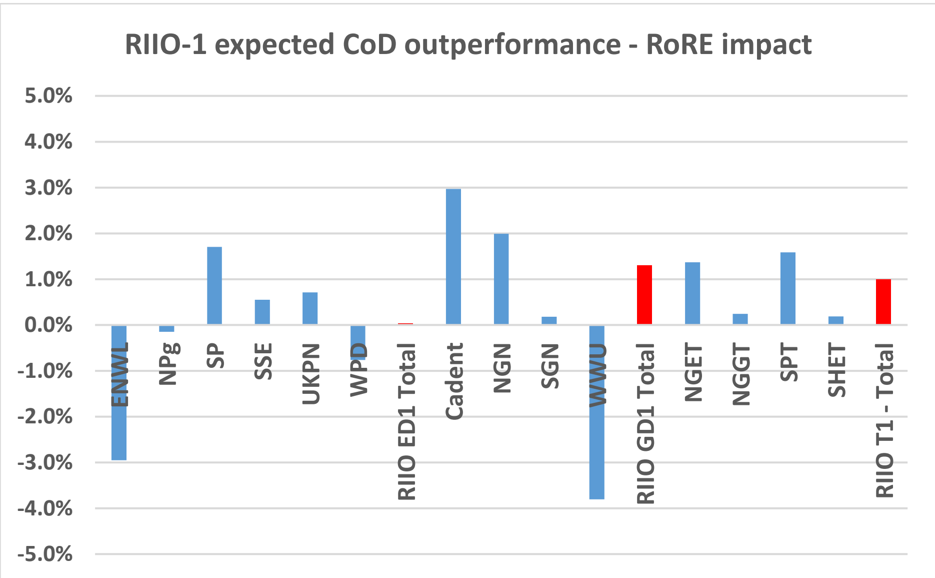
Whilst Ofgem has proposed to retain a full-indexation approach to the cost of debt for RIIO-2, the consultation also sets out that Ofgem "may also consider adjusted indexation mechanisms (such as that used for SHE-T in RIIO-1) for unusual company-specific circumstances, if appropriate and justified"[18].

We are concerned that Ofgem has not provided much detail about the circumstances in which companies could apply for an adjustment to the cost of debt, the types of evidence that would need to be provided or made clear whether it intends to consider making symmetrical adjustments whereby companies with lower than average cost of debt would receive a lower allowed cost of debt.

<u>Some companies will have higher cost of debt than the allowance, but some companies will have a lower cost of debt:</u>

The actual cost of debt that the network companies have been able to achieve varies across the industry, with some outperforming the relevant cost of debt in RIIO-1.

Figure 1 - RIIO-1 Expected Cost of Debt outperformance – impact on RORE[19]



[17] "Review of cost of capital ranges for Ofgem's RIIO-2 for onshore networks", page 38.
[18] See https://www.ofgem.gov.uk/system/files/docs/2018/12/riio-2_finance_annex.pdf
[19] Source: Supporting data file to regulatory financial performance annex to RIIO-1 2017/18 annual report

It is clear from the above that companies like Electricity North West and Wales & West Utilities are likely to seek increases in the allowed cost of debt to reflect their relatively expensive embedded debt. However, it is also clear that some companies have outperformed the allowed cost of debt under RIIO-1, such as Cadent Gas, which raised all of its debt relatively recently and has achieved windfall gains simply due to the timing of its divestment from the National Grid Group. We also note that at a sectoral level, for gas distribution and transmission, the level of outperformance of the cost of debt allowance in RIIO-1 is expected to add c. £1.1bn[20] to the networks' returns.

This indicates that, despite full indexation of the cost of debt under RIIO-1, which has meant that reductions in the market cost of debt in recent years have been somewhat reflected in the allowed cost of debt (but not fully because the index relies on a trailing average), there is the potential for consumers to benefit further if the actual cost of debt of some of the leading companies is passed through to consumers (rather than being allowed to accrue to shareholders as an unearned windfall gain). On the other hand, there is potential for detriment to consumers if companies with relatively expensive debt are allowed to pass through some of that higher cost of debt to consumers.

Looking forward to RIIO-2, there is the potential for this situation to play out again; the current cost of new debt is likely to be below the trailing index, which includes historical data from when the cost of debt was more expensive, so that it is possible some network companies will outperform the allowed cost of debt during RIIO-2.

This raises a question for Ofgem about how best to set the cost of debt for companies which have an actual cost of debt materially above or below the cost of debt implied by the debt indexation methodology.

<u>Ofgem should have regard to approaches to the cost of debt of other regulators:</u>
We encourage Ofgem to have regard to the approach Ofwat is taking for PR19. Ofwat have allowed companies to request a company-specific upward adjustment to the allowed the cost of debt. Ofwat stated that they would apply a cost of capital test to assess[21]:

- Whether there is compelling evidence of consumer support for the proposed adjustment?
- Whether there is compelling evidence that there are benefits that adequately compensate consumers for the increased cost?
- Is there compelling evidence that the level of the requested adjustment is appropriate?

A key benefit that Ofwat has required for PR19 is that the company shows it is efficient. Ofwat has recently announced that it intends to reject all but one request from companies for an uplift to the allowed cost of capital, with the only exception being for one of the companies that proposed costs below Ofwat's assessment of efficient costs and which has the lowest bills of all the water companies in England and Wales.

[20] Source: Supporting data file to regulatory financial performance annex to RIIO-1 2017/18 annual report
[21] See https://www.ofwat.gov.uk/wp-content/uploads/2019/02/Technical-Appendix-4-Company-Specific-Adjustments-to-the-Cost-of-Capita....pdf

In addition, Ofwat encourages companies to develop benefit sharing arrangements for the cost of debt where it is in the interest of consumers to do so, and for PR19 will require companies to implement sharing mechanisms where financing outperformance relates to high levels of gearing.

The design of company specific adjustments to the cost of debt needs to be carefully thought through:

Noting all of the above, for RIIO-2 Ofgem should carefully consider the design of any company-specific adjustments to the cost of debt to ensure that the price controls are fair and transparent for consumers.

Companies seeking an increase in the allowed cost of debt should have to pass a high evidential bar before Ofgem allows them a higher cost of debt. Ofgem should ensure that companies which have incurred higher allowed costs of debt are not able to pass those costs through to consumers except in very limited circumstances, and incentivise the network company to reduce those costs where possible. If a company has raised finance inefficiently then it should be the company's shareholders which are responsible for funding any shortfall, not consumers. We would encourage Ofgem to consider introducing consumer benefits tests and cost efficiency tests similar to those Ofwat has proposed. There should be clear evidence that consumers support a higher cost of debt and there should be strong incentives for companies with high costs of debt to ensure that they are delivering services that represent good value for money for consumers overall (taking into account any higher cost of debt).

At the same time, since no company is going to voluntarily request a reduction to its allowed cost of debt, it can be reasonably assumed that this will be viewed as a one-way option only by the network companies: those with higher cost of debt will request increases in their allowed cost of debt, but companies with relatively low cost of debt will make no request for a downward adjustment to their cost of debt. This raises a question of how best to set the allowed cost of debt for companies with below average actual costs of debt.

There is no reason in theory why adjustments and sharing mechanisms, for any price control parameter, cannot be applied in a symmetric fashion, i.e. those with higher costs and those with lower costs would be subject to an upward adjustment and a downward adjustment, respectively. Moreover, there is a strong argument that Ofgem should ensure that shareholders do not benefit from windfall gains arising from financing outperformance as it is inconsistent with encouraging increased focus by energy networks on delivering operational and service improvements for consumers in order to achieve financial rewards and it is also difficult to justify in terms of fairness to expect consumers to pay for financing costs which are not being incurred.

In our view, Ofgem should ensure that consumers of companies with lower cost of debt benefit from that lower cost and do not simply pay unnecessarily high bills that produce windfall gains for shareholders. With that in mind Ofgem should introduce company-specific adjustments to the cost of debt for companies with lower costs of debt and/or require companies with lower cost of debt to share some of this outperformance with consumers.

We leave it to Ofgem to propose the detailed design of such a mechanism, but expect that those details can be set out in the RIIO-2 Sector Specific Methodology Decision. We would encourage

Ofgem to consider not only the points we have made above, but also to recognise that companies which might start the period with a higher-than-allowed cost of debt could end the period with a lower-than-allowed cost of debt, as embedded debt matures and is replaced with new, lower cost debt. Ofgem's methodology for company-specific adjustments to the cost of debt will need to be flexible to changes in the cost of debt, so it may be appropriate to consider some kind of re-financing gain-share mechanism and/or an ex-post adjustment to reflect any differences between the expected cost of debt over the RIIO-2 period and the outturn cost of debt companies actually incur.

FQ4. Do you have a preference, or any relevant evidence, regarding the options for deflating the nominal iBoxx as discussed in Finance annex paragraph 2.14? Are there other options that you think we should consider?

We are supportive of the approach (ii) which deflates nominal iBoxx in one step using an expected value for CPIH, and we agree this value should be based on the longest-term horizon available in the Office for Budget Responsibility (OBR) forecast (5-year forecast). We do not think it is appropriate to use multiple years of inflation expectations as this risks 'baking in' short term inflation fluctuations to a longer-term cost of debt.

If approach (i) is applied, we note that the CEPA review highlighted the current mismatch between the length of the debt tenor for the iBoxx index (c. 20 years on average) and the time horizon for breakeven inflation (currently 10yrs)[22]. This mismatch should be addressed and a 20-year breakeven inflation would seem to provide a better measure for converting the nominal yield into an equivalent real yield.

Risk-free rate questions:

FQ5. Do you agree with our proposal to index the cost of equity to the risk-free rate only (the first option presented in the March consultation)?

We agree with this proposal, and that the risk-free rate (RFR) is readily accessible and relatively uncontroversial, whereas there is more debate about the nature of the equity risk premium (ERP). Also, we note CEPA previously highlighted the difficulty of constructing a robust relationship for an offsetting adjustment between the RFR and the Total Market Return (TMR)[23], which would be required for option c). The development of such a relationship is likely to require more judgment which could introduce an additional source of forecasting error.

It is also necessary to consider how the downward impact of other mechanisms on the cost of equity can be captured in final approach to remunerating investors.

[22] "Review of cost of capital ranges for Ofgem's RIIO-2 for onshore networks", page 38.
[23] "Review of cost of capital ranges for Ofgem's RIIO-2 for onshore networks", page 57.

FQ6. Do you agree with using the 20-year real zero coupon gilt rate (Bank of England database series IUDLRZC) for the risk-free rate?

We agree this is a reasonable approach.

FQ7. Do you agree with using the October month average of the Bank of England database series IUDLRZC to set the risk-free rate ahead of each financial year?

We agree this is a reasonable approach.

FQ8. Do you agree with our proposal to derive CPIH real from RPI-linked gilts by adding an expected RPI-CPIH wedge?

We agree this is a reasonable approach.

TMR questions:

FQ9. Do you have any views on our assessment of the issues stakeholders raised with us regarding outturn inflation, expected inflation, and the calculation of arithmetic uplift (from geometric returns)?

We agree with the assessment provided by Ofgem which deals with these concerns. As set out in further detail below, we consider it more probable that Ofgem's TMR range remains overly generous.

FQ10. Do you have any views on our interpretation of the UKRN Study regarding the TMR of 6-7% in CPI terms and our 6.25% to 6.75% CPIH real working assumption range based on the range of evidence?

Ofgem has proposed a range for the TMR of 6.25 – 6.75% in real CPIH-stripped terms based on its interpretation of the results of a number of different methods for estimating the TMR. It is not clear how Ofgem have arrived at the proposed range of 6.25 – 6.75% based on the information presented. We note, however, that two of the three methods for estimating the TMR considered by Ofgem suggest that the TMR could be materially lower than the range Ofgem has ultimately assumed. That being the case, we set out below some additional evidence which Ofgem may wish to have regard to when finalising its views on the TMR for RIIO-2.

Table 1: Ofgem's methods for determining the TMR

Method	Nominal	Real CPI*	Real CPIH
Long-term rates of return in the UK equity market as advised by UKRN, using data from Dimson, Marsh and Staunton	-	6% - 7%	-
CEPA's DDM model (including share buy-backs)	7.9% - 8.5%	5.9% - 6.5%	-
Survey of investment professionals	6.59%	4.59%	-
Ofgem's proposed range for TMR	-	-	6.25% - 6.75%

Source: Ofgem's RIIO-2 Sector Specific Methodology Consultation

**Assuming 1% wedge between RPI and CPI and a conservative assumption of 2% deflation to reach CPI values*

Ofgem may have placed too much weight on historical returns data:

As noted above, Ofgem has had regard to a range of different methods for estimating the TMR. We consider that this is appropriate given the TMR is not observable and there is no consensus amongst academics or practitioners on the single best methodology to use.

We consider the methods which Ofgem has had regard to are reasonable, though not exhaustive. There are several approaches to estimating the TMR which can be considered reasonable methods given they have been used widely in the academic literature and in practice, including methods based on historical outturn data and on forward-looking methods derived in different ways.

Table 2: Methods for determining TMR

Method	Description	Example
Historical ex-post	Studies that assume that historical realized returns are equal to investors' expectations	Long-term rates of return in the UK equity market
Historical ex-ante	Studies that fit models of stock returns to historical data to separate out ex-ante expectations from ex-post good or bad fortune	Dividend Discount Models (DDMs)
Forward looking approaches	Studies that use current market prices and surveys of market participants to derive current forward-looking expectations	Surveys of market participants

Source: Competition Commission

We note that the methods which Ofgem has considered are consistent with the recommendations from the 2017 The UK Regulators Network (UKRN) study[24], which recommended that regulators base their estimate of the TMR on long-run historic averages, taking into account both UK and international evidence. Ofgem broadly follows this approach, estimating the TMR by looking at

[24] https://www.ukrn.org.uk/wp-content/uploads/2018/11/2018-CoE-Study.pdf

the historical long-run average of market returns, while also considering whether this matches with historical ex-ante methods (CEPA were commissioned to produce a Dividend Discount model (DDM)) and forward-looking approaches, including a survey of investment professionals.

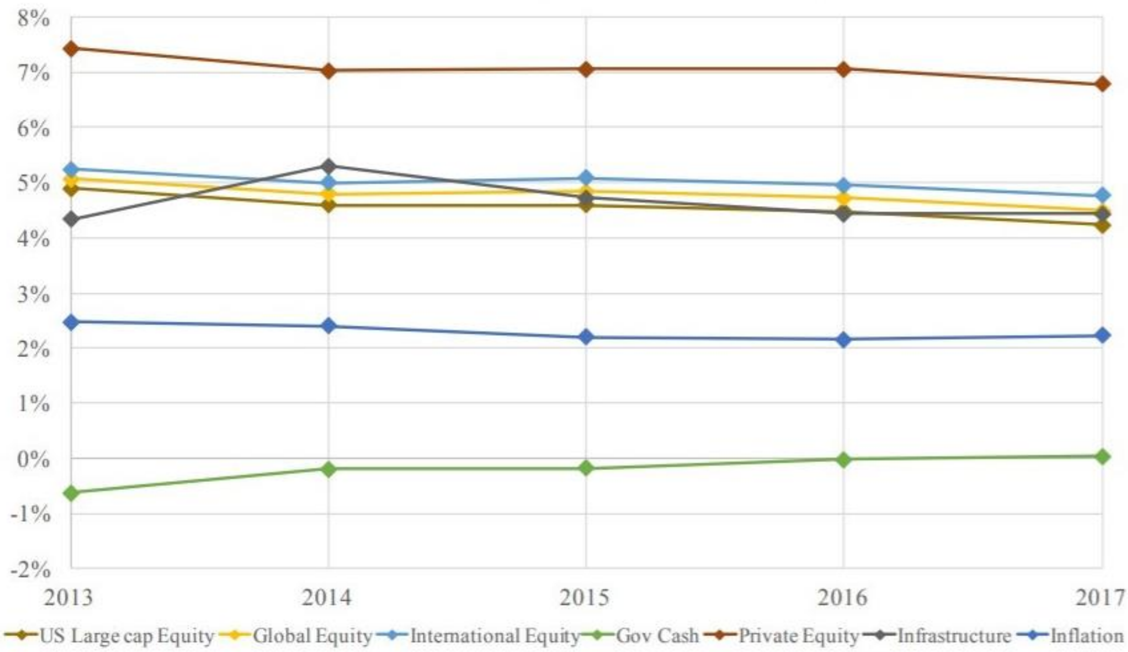
We are not convinced that Ofgem has placed appropriate weight on each of the different methods that it has considered. Ofgem's estimate of the TMR for RIIO-2 is only marginally below the TMR assumed for RIIO-1. So, while we believe it is correct for Ofgem to review the TMR and reduce the level from RIIO-1, it is not clear if Ofgem has placed enough weight on current evidence in line with the UKRN's 'cost of capital principles'[25], which includes a commitment to regularly reviewing the parameters for the cost of capital.

The TMR tends to be stable over time, as its component elements are negatively correlated, and therefore as the RFR rises, the ERP falls. This has been detailed in a number of academic publications[26]. However, the TMR is not a fixed parameter, and can change over time in line with investor expectations. There is a variety of evidence – as we illustrate below - to show that TMR has decreased in recent years and will remain at a low level for the duration of the price control.

<u>Investor expectations:</u>

The UKRN's report on the cost of equity points to a decline in expected return based on investor surveys. It suggests a growing consensus of financial practitioners that expected returns on global stock markets have been weakening in recent years.

Figure 2: Compound Average Real Expected Returns, 10-year horizon



Source: UKRN report, based on data from Horizon Actuarial Services and Survey of Capital Market Assumptions, editions 2012-2017

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[25] https://www.ukrn.org.uk/wp-content/uploads/2018/06/2016MarCoC-Principles.pdf

[26] For example, see De Paoli and Zabzcyk (2009) "Why do risk premia vary over time? A theoretical investigation under habit formation", Bank of England Working Paper No. 361

Vanguard investment, in their Economic and Market Outlook 2018, have also stated that "…*Recent returns have been largely driven by a recovery from the huge market falls during the financial crisis, with equity market valuations buoyed further by low interest rates and quantitative easing. These tailwinds cannot last indefinitely...*"[27]

Other investors[28] point to downward revisions to long run productivity, lower forecasts of GDP growth, and higher stock market valuations as a result of the low interest rate environment, which leads to weaker dividend yields.

To some extent, investors can predict long term returns, for example using cyclically adjusted P/E multiples[29]. This suggests more weight should be given to investor views. While there is not necessarily a good quantitative method to determine the expected return, we believe Ofgem's survey of investment professionals provides a good starting point, and suggests that a TMR below historical averages would be appropriate. We also note that investor views can be subject to optimism bias[30], which would suggest an even lower TMR could be justified.

Low Interest Rates:

One obvious reason for the reduction in the TMR in recent years is the period of record low interest rates that has prevailed in the UK and many advanced economies since the global financial crisis. There has been some debate about whether the TMR assumption should be revised downward as a result of the prolonged period of very low interest rates that the UK has experienced since the financial crisis, which flow through into equity markets. Moreover, notwithstanding some modest increases in official interest rates in the last year or so, future expectations of interest rates also remain low, as demonstrated by the yields on long-term government bonds.

The policy of Quantitative Easing (QE) has decreased long-term bond yields, increasing the present value of future dividends and therefore increasing equity values. As investors move away from bonds towards equities the ERP should fall[31], lowering the TMR. The Bank of England has stated that an end to QE would only be acceptable after interest rates have risen a few times.

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[27] https://www.vanguardinvestor.co.uk/articles/latest-thoughts/markets-economy/why-investors-prepare-for-lower-returns

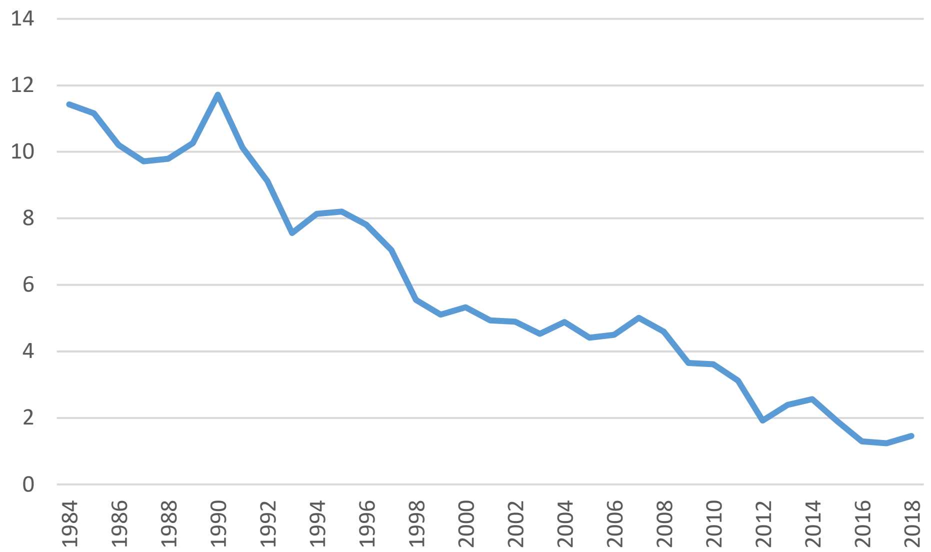
[28] Including the FCA https://www.fca.org.uk/publication/research/rates-return-fca-prescribed-projections.pdf, Lazard https://www.lazardassetmanagement.com/docs/-m0-/1313/LazardOnTheUK_2019Q1_en.pdf, and Schroders https://www.schroders.com/en/sysglobalassets/digital/insights/2017/pdf/2018_long_run_forecasts_cb.pdf

[29] Price–Earnings Ratios as Forecasters of Returns, Robert J. Shiller, 1996 http://www.econ.yale.edu/~shiller/data/peratio.html

[30] See for example The Courage of Misguided Convictions, Barber and Odean, 1999

[31] The financial market impact of quantitative easing, Bank of England, 2010 https://files.stlouisfed.org/files/htdocs/conferences/qe/wp393.pdf

Figure 3: Annual average yield from 10-year British Government Securities

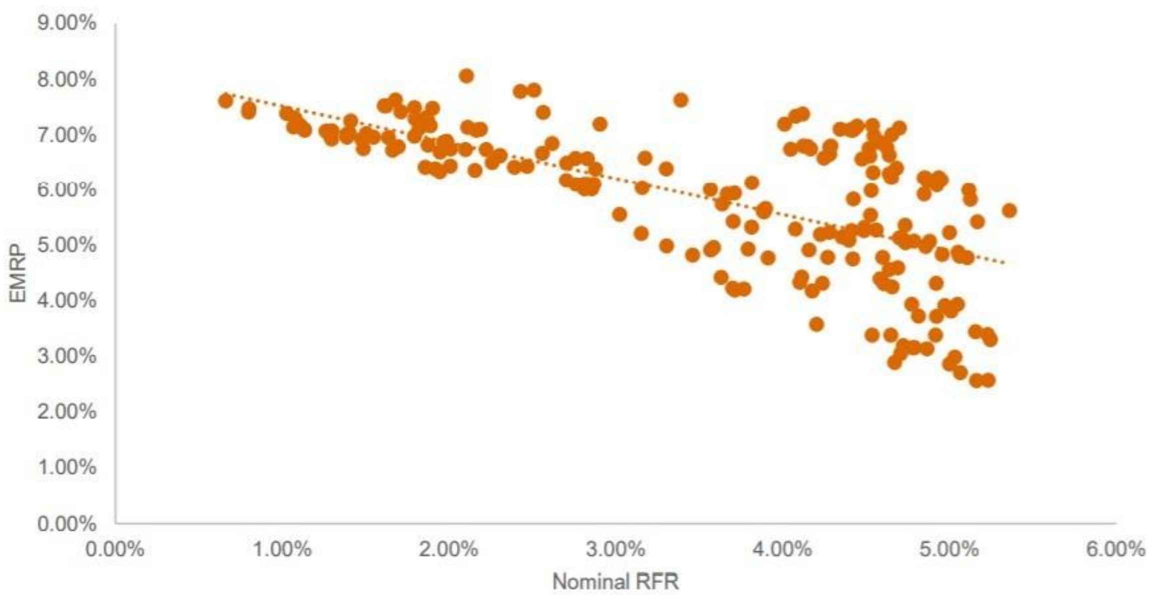


Source: Bank of England data

<u>Less than perfect correlation between the risk-free rate and the market risk premium:</u>

A PWC report for Ofwat[32] as part of PR19 considered that a further reason the TMR has decreased is that the negative correlation between the RFR and the market risk premium (MRP) is less than one, meaning that as the RFR has fallen, it has not been offset in full by an increase in the ERP, and therefore TMRs have fallen.

Figure 4: Relationship between the risk free rate and equity risk premium from implied DDM model



Source: PWC report for Ofwat

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32 https://www.ofwat.gov.uk/wp-content/uploads/2017/12/PwC-Updated-analysis-on-cost-of-equity-for-PR19-Dec-2017.pdf

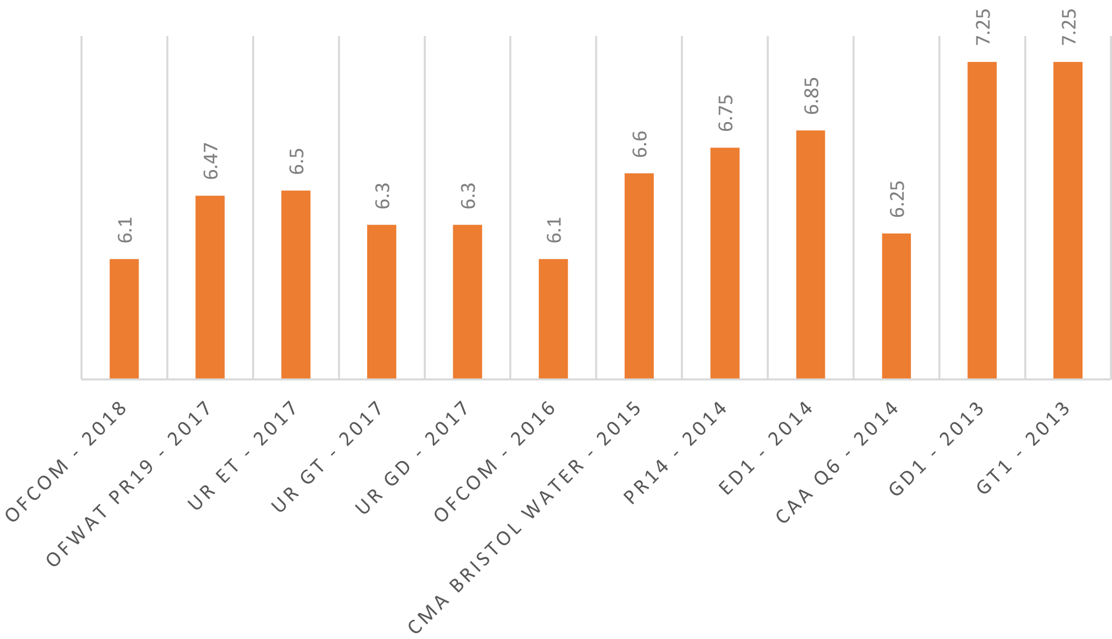
UK regulatory precedent:

A number of UK economic regulators have recently reduced, or proposed reducing, the TMR assumption compared to earlier price reviews. Ofwat, in their proposal for PR19[33] estimated a central figure of 6.47% real CPIH for TMR, compared to 6.75% in PR14. It cited "a fundamental change in economic conditions since the financial crisis" through which there has been falling yields across a range of assets including equities. It also pointed towards medium term forecasts, such as from the OBR, which suggested growth will remain low and weakness in productivity will continue until at least 2022.

Placing more weight on forward-looking methods for estimating the TMR may be more in line with the views of the Competition Commission, which stated in the Northern Ireland Electricity appeal during 2014 *"…it is now appropriate to move away from this upper limit based on historical ex post realized returns and place greater reliance on ex ante estimates derived from historical data…"*[34].

Ofgem's estimate of TMR is broadly in line with the recent decisions of other regulators.

Figure 5: Past regulatory decisions on total market return



Source: Various regulators' price control determinations

[33] https://www.ofwat.gov.uk/wp-content/uploads/2017/12/Appendix-12-Risk-and-return-CLEAN-12.12.2017-002.pdf

[34] Competition Commission final determination, Northern Ireland Electricity price determination, 2014, pg 388
https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf

International regulatory precedent:

Given that UK energy networks compete with international energy networks for investment, Ofgem might also have regard to the TMR estimates adopted by international economic regulators. We have set out below a table of the TMR used by other energy regulators.

Table 3: International comparison of TMR

Country	Sector	Reg period	TMR
Australia	Gas	2017-2022	6.52%
Australia	Electricity	2017-2022	6.57%
Germany	Gas	2018-2022	4.83%
Germany	Electricity	2019-2023	4.83%
France	Gas	2017-2021	6.60%
France	Electricity	2017-2021	6.60%
Denmark	Gas	2018-2021	4.00%

Source: Regulators' web pages

A simple dividend discount model of the FTSE 100 estimate of the TMR:

The DDM is based on the theory that a stock is worth the present value of all its future dividends. It allows us to calculate the nominal cost of capital as the sum of its dividend yield and its long-term growth rate.

There are various ways in which the DDM can be calculated. In its simplest form the model can be described as:

$$\text{nominal cost of equity} = \frac{D}{P} + g$$

where:

D/P = dividend yield

g = long term growth rate

The model is implicitly geometric as the growth in dividends is assumed to be constant.

We have applied this model for the FTSE 100 to test Ofgem's assumptions of TMR. We have estimated the long-term growth rate using the historical growth rate of dividends since 1980, which is 1.6%[35]. We have calculated the dividend yield using historical data of the FTSE100 from the last 5 years, which is 4.4%.

Table 4: FTSE 100 dividend yields over the last five years

2014	2015	2016	2017	2018
4.65	4.22	3.99	4.02	4.91

Source: Bloomberg

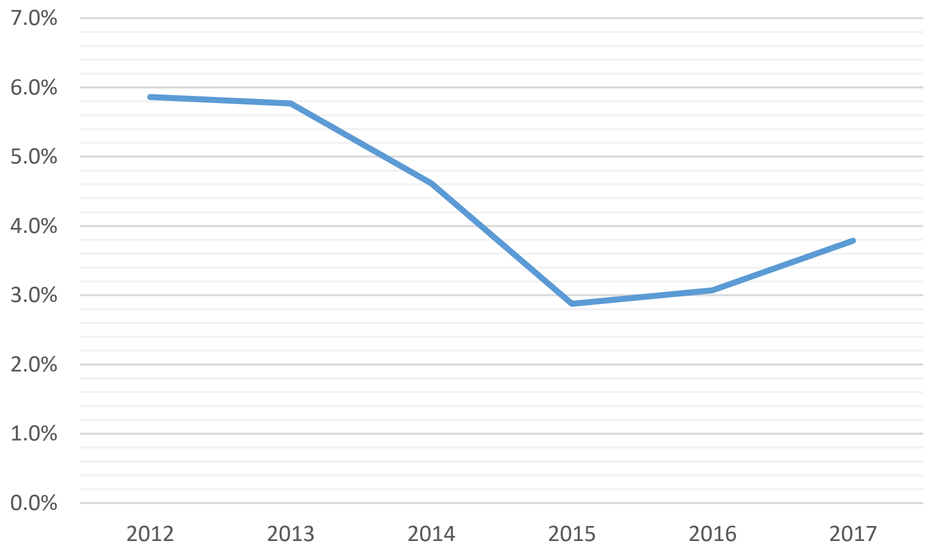
The cost of equity given by our model is therefore 1.6% + 4.4% = 6.0%. This suggests that a TMR below Ofgem's 6.25 – 6.75% range might be more reasonable for RIIO-2.

[35] https://assets.publishing.service.gov.uk/media/54edfe9340f0b6142a000001/Cost_of_capital.pdf

Evidence from Dimson Marsh and Staunton:

Even if Ofgem considers that long run historical equity returns data remains the most appropriate way to estimate the TMR for RIIO-2, reviewing long term historical equity returns data from the Dimson, Marsh and Staunton sourcebook 2018 provides evidence that TMR has declined since the RIIO-1 price control.

Figure 6: 10y Rolling Average of Compound Annual Growth Rate of Equities



Source: Dimson, Marsh and Staunton sourcebook 2018

Conclusion:

Noting all of the above evidence that suggests TMR changes over time and has decreased materially since RIIO-1, Ofgem's approach to the TMR for RIIO-2 risks placing too much weight on a relatively static measure of the TMR i.e. long term historical averages which are, by their very nature, slow to change over time (as each new year of data is only a small percentage of the overall observations in the time series) and accordingly may fail to take into account recent developments which suggest a lower TMR.

We , therefore, encourage Ofgem to consider if it is has placed sufficient weight on the DDM and survey based estimates of the TMR.

Equity beta questions

FQ15. What is your view of the proposed Ofgem approach with respect to beta?

Ofgem have proposed an asset beta of between 0.35 – 0.36 and a debt beta of between 0.10 and 0.15, which implies – in combination with a notional gearing assumption of 60% - a notional equity beta between 0.65 – 0.76. This is lower than the corresponding assumptions for RIIO-1, and we think closer to the true value of beta for energy networks in Great Britain. While a reduction in beta will enhance the legitimacy and fairness of the price controls, we also think there is evidence that an even lower range for notional equity betas would be justified.

Beta is significantly lower than for RIIO-1:

Equity beta is an estimate of the riskiness of investing in one company compared to investing in the equity market as a whole. Traditionally, economic regulators in the UK have used simple econometric techniques such as ordinary least squares (OLS) to derive raw equity beta estimates. Specifically, they have looked at the historical relationship between a group of comparator stock prices and the whole market. Regulators have traditionally used short samples of daily data to allow a point estimate for beta. This is the kind of approach Ofgem used at RIIO-1.

However, there is evidence that these techniques may overestimate the true value as they fail to take into account the movement of beta over time[36]. It is generally accepted that betas can change over time, in which case OLS estimates will suffer from heteroscedasticity and will probably overestimate the true beta. Indepen found that there is a heteroscedasticity problem for all network companies when using daily or weekly data observations[37]. This tends to suggest that the techniques used in the past may have overestimated the beta for energy networks.

Short windows and point estimates of beta may also be more reflective of the use of beta by the finance industry, which cares more about short horizons. The UKRN, study[38] on the appropriate methodology for setting the cost of capital recommends that all components of the CAPM model, including beta values, are estimated using a methodology that is consistent with the chosen horizon. Ofgem's time horizon should therefore be consistent with that used in setting the RFR and the TMR. This means estimating betas using a longer time series of data, not just the last couple of years.

The UKRN report also recommends that regulators make more use of robust econometric estimates of equity beta and that sound econometric evidence and practice, utilising all available data should be used when calculating the betas of listed companies.

We believe that the above points mean that Ofgem is correct to modify its approach to calculating beta values and specifically to use a generalised autoregressive conditional heteroskedasticity (GARCH) model to take into account movement in beta values over time, and to consider both high frequency and lower frequency observations to help remove heteroscedasticity.

Ofgem's proposal to adopt a non-zero debt beta is also a step in the right direction. Debt beta is a measure of the systematic risk of corporate debt. It is often assumed to be zero (and was at RIIO-1), but this assumes none of the systematic risk of higher gearing is transferred to debt investors (which is unrealistic) and all of that risk is transferred to equity investors. This can have the effect of overstating the equity beta because it will reflect systematic risk that has actually been transferred to debt investors rather than equity investors.

It is appropriate therefore that Ofgem assumes a non-zero debt beta. We note that Ofgem's choice in line with figures used in other regulatory decisions, which range between 0 – 0.15, as

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36 This has been known for a long time. See for example "Beta as a Random Coefficient", Fabozzi and Francis, 1978

37 https://www.ofgem.gov.uk/system/files/docs/2018/12/final_beta_project_riio_2_report_december_17_2018_0.pdf

38 https://www.ukrn.org.uk/wp-content/uploads/2018/11/2018-CoE-Study.pdf

summarised in the table below. We also note Indepen highlighted that there is academic support for a range of 0.05 – 0.22.

Table 5: Debt beta used in other regulatory decisions

Regulator / decision	Debt Beta
Ofwat – PR19	0.10
CC Heathrow Q5	0.10
CAA H7	0.05
PR14	0
Ofcom 2014	0.10
CMA Bristol Water appeal	0
Ofgem RIIO-1	0
Ofcom 2013	0.15
CMA NIE	0.05

Source: Various regulatory decisions

Aside from the emergence of new, better, techniques for the estimation of betas, and the adoption of a non-zero debt beta, it is worth recalling that there are a number of other aspects of the proposed RIIO-2 regulatory framework which help to de-risk investment compared to RIIO-1 and therefore are consistent with lower equity betas. Some of these measures are summarised in the table below.

Table 6: Measure which de-risk investment in RIIO-2

Control	How it can de-risk investment
Indexation of the cost of equity	Indexation protects networks from changes to the risk-free rate. If the risk-free rate, measured by the yields on long term government bonds, were to rise, then the cost of equity would rise accordingly.
Return adjustment mechanisms	Ofgem are proposing mechanisms which would protect companies from the costs of overspending: • Under sculpted sharing, individual companies would have their RoRE adjusted if it deviates from a predetermined collar. This means that consumers would share the costs of a network's underperformance. • Under anchoring the network companies will have adjustments to the RoRE based on the sector's performance as a whole. This means that consumers could share the costs of the sector underperforming.
Indexing of real price effects	Adjustments for real price effects protect companies from the risk of their input costs rising above inflation.
Modified tax trigger mechanism	The tax trigger mechanism allows networks to increase their allowed revenue in accordance with the tax they pay, protecting them from the risk that tax rates increase. While this provision existed in the RIIO-1 framework, Ofgem are consulting on modifying it, including consideration of passing through actual tax costs.
Other uncertainty mechanisms	Uncertainty mechanisms will protect companies from the effects of the energy system changing unexpectedly. Specific mechanisms are included for cyber resilience and for projects relating to whole system outcomes. Networks can also propose their own uncertainty mechanisms which could allow them to increase their allowed revenue should specific future events require them to spend more.
Shorter price control	A shorter price control allows the cost of capital to be updated more often and protects the networks from increases to the cost of capital.
Cashflow floor	If a company becomes unable to finance its debt obligations the cashflow floor means networks can receive top up payments, paid back over time. This reduces their risk of default.

Source: Ofgem RIIO-2 Sector Specific Methodology Consultation documents

<u>Beta may actually be lower than Ofgem have proposed:</u>

As noted above, we welcome the various improvements and refinements to Ofgem's approach to estimating betas for RIIO-2. However, there is evidence that an even lower beta value could be justified which we believe Ofgem should have regard to before finalising its estimate of the betas for RIIO-2. This evidence includes:

- The Indepen report recommends a broad range of 0.55 – 0.7 and a narrow range of 0.57 – 0.65, with 0.6 as the central estimate. Ofgem have not sufficiently justified why they have adopted a more conservative range.

- Short time horizon used for top of range: the top end of Ofgem's raw equity beta range has been derived from a five-year dataset, and therefore may be inconsistent with the UKRN report, which recommends that all components of the CAPM model are estimated using a methodology that is consistent with the chosen horizon, which would justify a longer range for computing beta. We also note that CEPA have shown[39] the relationship between asset beta and equity beta expected through the level of gearing does not hold in the short run, but does hold in the long run. This suggests it would be better for regulators to use long time horizons when estimating beta values.

- No 'pure play' comparators: since there are no 'pure play' listed energy network companies in the UK, Ofgem does not have access to an ideal comparator for estimating betas. The necessary reliance on proxies, whose businesses include either unregulated activities or pursuits in different sectors, may lead to a bias in the beta estimates. It is likely that this will be an overestimation, as the other activities are likely to present more risk than regulated ones.

- 'Re-gearing' may be unnecessary: A standard methodology of regulators (including Ofgem) is to estimate equity betas from market data and then 'de-gear' these estimated equity betas to derive asset betas. Where a regulator's notional leverage differs from observed market leverage, it will 're-gear' the asset beta to derive the equity beta for the notional company, which will be used in the CAPM model. However, Mason, Pickford and Wright are sceptical of the assumptions underlying 're-gearing'[40]. They believe that the estimated equity beta determines the marginal cost of equity, and should be used directly if a company is listed. This would tend to lead to lower beta values.

- Academic views: three of the authors of the UKRN report, Mason, Pickford and Wright, believe that the equity beta assumed in recent price controls (including the values of 0.8 and 0.9 chosen by Ofwat and Ofgem respectively) are inconsistent with econometric evidence. They point to evidence that shows estimation on longer-term data and at lower frequencies results in distinctly lower equity beta estimates, in the range 0.3-0.5. Their view is supported by evidence from Market Asset Ratios (MARs), which show that network companies are continually valued above their regulated asset base. In their view one plausible reason for this could be that betas are much lower than regulators' estimates.

It is also worth noting that Ofgem's estimates of notional equity betas remain much higher than other regulated utilities internationally. Given that energy networks in Great Britain will be competing for capital with other similar businesses around the world it is not obvious that the cost of equity should be higher in GB than elsewhere (and this would be the natural implication of assuming a higher equity beta, all else equal).

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[39] https://www.ofgem.gov.uk/ofgem-publications/52014/short-term-relationship-between-asset-and-equity-betas-cepa-2010pdf
[40] Estimating the cost of capital for implementation of price controls by UK Regulators, pg 10
http://www.bbk.ac.uk/ems/faculty/wright/wrightburnsmasonpickford2018.pdf

Table 7: Equity betas for a number of international utility companies

Equity	Country	Industry	Market Cap (£)	Equity Beta*
American Electric Power Company Inc	United States	Electricity	30.18bn	**0.153**
American Water Works Company Inc	United States	Gas, Water & Multi-utilities	13.85bn	**0.2399**
Algonquin Power & Utilities Corp	Canada	Electricity	4.17bn	**0.4842**
Atmos Energy Corp	United States	Gas, Water & Multi-utilities	8.71bn	**0.2546**
CenterPoint Energy Inc	United States	Gas, Water & Multi-utilities	11.39bn	**0.4436**
Spark Infrastructure Group	Australia	Electricity	2.10bn	**0.3354**

*Source: FT equities screener; companies over £2bn market cap, worldwide utilities and selected for their focus on regulated business; *5 year equity beta from the Multex Ratios and Statistics table, provided by Reuters*

Ofgem's estimated range for the equity beta is not out of step with those assumed by other economic regulators. However, given Ofgem is the first regulator to adopt the new, improved techniques (e.g. GARCH) outlined above, it is arguable that Ofgem's equity beta for RIIO-2 should be lower than those other historical beta estimates.

Table 8: Equity betas assumed by other UK regulators

Price control	Year	Asset beta	Notional Equity beta
Ofcom WLA UK telecoms	2018	0.73	1
Ofwat PR19 (provisional)	2017	0.37	0.77
UR RP6	2017	0.38	0.61
CMA GD17 Firmus	2017	0.4	0.77
UK GD17 PNGL	2016	0.4	0.77
Ofcom LLCC Openreach	2016	0.55	0.74
CC NIE	2015	0.35 - 0.4	0.6 - 0.7
ORR CP5	2013	0.37	0.95

Source: Various regulatory decisions; UKRN Annual WACC summary

Conclusion:

The evidence above suggests Ofgem have estimated a notional equity beta that is closer to the true value of beta for energy networks in Great Britain relative to RIIO-1, and used econometric techniques which have helped deal with the issues such as heteroscedasticity that have biased previous estimates.

However, we note that a number of other good arguments have been put forward that equity betas might be even lower, including by academics in the UKRN report, and through international comparison. As well as these downside arguments, there are also a number of measures which de-risk investment in the networks in RIIO-2 which we encourage Ofgem to take into account when choosing a notional equity beta.

Cross-checking the CAPM-implied cost of equity questions:
FQ16. Do you agree with our proposal to cross-check CAPM in this way?

It is sensible to cross check the CAPM-implied cost of equity. However, Ofgem appears to be adopting a conservative approach in bringing the constituent elements together and applying the cross checks. For instance, Ofgem does not appear to give much, if any, weight to the views of investment managers and advisors in either this section or in the section on TMR.

FQ17. Do you agree that the cross-checks support the CAPM-implied range and lend support that the range can be narrowed to 4-5% on a CPIH basis?

For the reasons set out above in relation to the TMR and Equity Beta values, we believe the lower end of 4.0% is likely to be too high. Further, Ofgem have rounded up the Indepen range of for the raw equity beta (from 0.55 – 0.7 in the Indepen report, to 0.6 – 0.7). Therefore, we do not agree with the narrowing of the downside range to 4.0% (from 3.8%). As Ofgem notes, the financial impact of each 10bps (10 basis points or 0.10%) on the cost of equity is worth approximately £172m over the course of the RIIO-2 price controls. Whilst we note these values are purely illustrative at this stage, such rounding up needs to be fully justified.

Expected and allowed return questions
FQ19. Do you agree with our proposal to distinguish between allowed returns and expected returns as proposed in Step 3?

Ofgem has proposed an adjustment to the allowed cost of equity of around 50 basis points of return, to reflect that investors expect companies to outperform the price control by around 50 basis points, thereby ensuring that the expected cost of equity (including expected outperformance) is equal to investors' required rate of return. We welcome Ofgem's recognition of this potential issue, However, we also note that it is important for Ofgem to set its cost allowances and output targets in a way that ensures companies cannot easily outperform them.

Investors may expect outperformance in excess of 50 basis points:
Ofgem has proposed an adjustment to the allowed cost of equity for network companies for outperformance equivalent to 50 basis points.

Calibrating cost allowances, performance targets and incentives is inherently difficult and it is more likely that companies will outperform these targets than underperform because:

- there is asymmetric information between the regulator and network companies in setting performance targets. Companies face a strong financial incentive in price control submissions to present a conservative view of the level of outperformance that is achievable.

- the risks to the regulator and to industry of setting overly challenging performance targets are also asymmetric - if set too tightly, they may lead to companies becoming financially unviable. A cautious regulator may be too lenient.

The tendency of regulators to set lenient performance targets that lead to excessive returns is borne out by both historical experience of network companies' performance under RIIO-1 as well as investor expectations for future price controls. For example, in RIIO-1, it is expected that all 26 networks will have outperformed against the allowed RoRE, while all four energy network sectors saw average sector outperformance (with the sector average forecast RoRE outperformance for RIIO-1 ranging from 0.7% to 4.0%). This is illustrated below.

Table 9: Forecast RoRE outperformance over RIIO-1 price controls, and forecast performance

	Allowance	Actual	% difference
ET1	7.0%	9.8%	2.8%
ED1	6.1%	9.4%	3.3%
GT1	6.8%	7.5%	0.7%
GD1	6.7%	10.7%	4.0%

Source: Analysis of Ofgem Annual Reports 2016-17 for each price control

As illustrated in the table below, most of the outperformance achieved in RIIO-1 has been against totex targets, which is an area of the price control where Ofgem has persistently (i.e. at several price control reviews, not just RIIO-1) underestimated the ability of network companies to spend less than allowances (whether due to efficiency gains or to forecast error). Across all energy sectors, Ofgem overestimated totex by 7% in RIIO-1.

Table 10: Forecast Totex outperformance (£m 2016/17 prices)

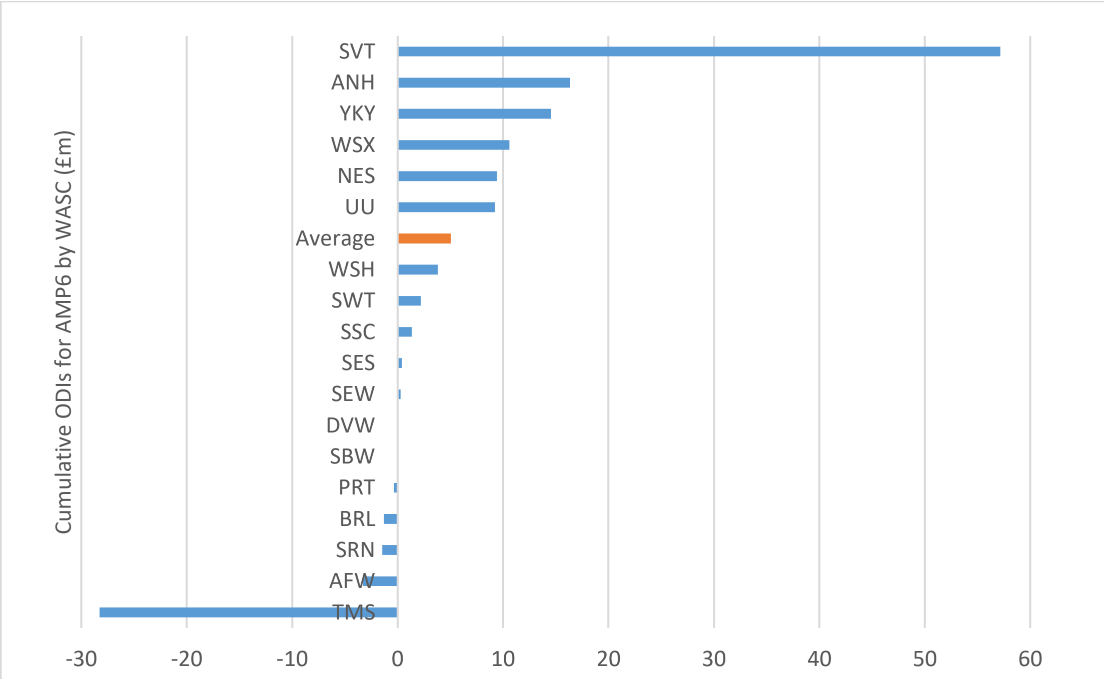
	Allowance	Actual	% difference
ET1	17,521	15,823	-10%
ED1	26,662	25,423	-5%
GT1	3,073	3,300	7%
GD1	17,621	15,511	-12%
Total	64,877	60,057	-7%

Source: Analysis of Ofgem Annual Reports 2016-17 for each price control

On the basis of the above, the level of company outperformance against allowed returns in RIIO-1 is likely to lead investors to anticipate that the cost allowances set by Ofgem for RIIO-2 will continue to be outperformable, regardless of any claims about RIIO-2 being a 'tough' price control and regardless of some of the other changes which Ofgem has proposed to make to the regulatory framework for RIIO-2 e.g. introduction of RAMs and a wider suite of uncertainty mechanisms.

Investors may also expect to outperform against RIIO-2 targets based on the experience of water and sewerage companies (WASCs). As shown below, the majority of water companies are outperforming Ofwat's PR14 targets (for the 2015-20 period). Investors in energy networks could read-across from the water to energy sectors and anticipate that Ofgem will provide similarly challenging targets for energy networks i.e. that those targets can be outperformed by the network companies.

Figure 7: Cumulative outperformance by water and sewerage companies in AMP6 (2014/15 to 2019/20)



Source: Ofwat[41]

Analysis of MARs also provides evidence that investors expect rewards for outperformance to continue going forward into future price controls. A MAR greater than one is evidence that investors expect to earn returns on the company's RAV in excess of the cost of equity.

We note that there has been a wide range of studies supporting the view that UK utilities are traded at a premium over their RAV, including the analysis Ofgem commissioned from CEPA. These findings have been supported by evidence from:

- Analysis of publicly traded share values of regulated WASCs (i.e. Pennon, Severn Trust and United Utilities), which identified a MAR of between 1.18 and 1.70. MAR premia.[42] This demonstrates that these companies have typically traded at a premium over their

[41] Outcomes, performance commitments and outcome delivery incentives 2016-17; https://webarchive.nationalarchives.gov.uk/20180207161659/https://www.ofwat.gov.uk/publication/outcomes-performance-commitments-outcome-delivery-incentives-2016-17/
[42] https://www.ofgem.gov.uk/ofgem-publications/130262

RAV, albeit one that has fluctuated over time. Similarly, PWC identified premia of 10% for United Utilities and 12% for Severn Trent based on analysis of MARs.[43]

- Analysis of M&A transactions involving privately held shares. As Ofgem noted in its "Open Letter on the RIIO-2 Framework", recent sales of interests in gas distribution networks occurred at prices representing premia of more than 40% above the RAV, while parties acquiring interests in the water sectors have paid premiums of 40-80% above the RAV.[44]

- Notwithstanding the latest consultations from Ofgem on its approach to RIIO-2, including a much lower WACC than RIIO-1, numerous infrastructure funds, strategic investors and even some of the incumbent DNOs have been linked with an upcoming sale of Electricity North West.[45]

The fact that significant MAR premia have been identified across a wide range of transactions and over several years strongly suggests that network companies have been, and continue to be, expected to outperform their price controls significantly. Moreover, the size of these MAR premia is consistent with investors expecting the energy networks to outperform quite significantly i.e. well in excess of 50 basis points.

Ofgem should review its assumptions about expected outperformance:

Given the historical levels of outperformance in both the energy networks and water sectors and the clear evidence from MARs, as well as signs that investor appetite for assets in the energy networks sector have not diminished, Ofgem may need to reconsider its assessment that a 50 basis points adjustment to the allowed cost of equity is sufficient to ensure that expected returns are equal to allowed returns and that the price controls are fair and transparent for consumers.

Whilst the expected-allowed return wedge and RAMs proposals have come about from the same underlying issue (systemic outperformance), they are trying to achieve different things and so should be considered separately. The expected-allowed return wedge is directly addressing an expectation of a level of outperformance. The RAMs are a failsafe mechanism if something goes wrong generating either systemic outperformance of systemic underperformance – this is demonstrated by the symmetric nature of the RAMs. The RAMs are required regardless of the level of expected-allowed return. Potentially, there may be some interaction around the expected-allowed return wedge and where the RAMs range is centred. If a 0.5% outperformance is expected then this may not be considered to be an indicator of any failing and so the symmetric range could be centred around the cost of equity without the expected-allowed wedge being stripped out i.e. a range that would appear asymmetric around the cost of equity. However, as we note below, we believe the proposed range for the RAMs needs to be tightened.

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43 https://www.ofwat.gov.uk/wp-content/uploads/2017/12/PwC-Updated-analysis-on-cost-of-equity-for-PR19-Dec-2017.pdf

44 https://www.ofgem.gov.uk/system/files/docs/2017/07/open_letter_on_the_riio2_framework_12_july_final_version.pdf

45 https://www.inframationnews.com/news/3412061/hicl-preps-bid-for-electricity-north-west.thtml and https://www.inframationnews.com/news/3253076/strategics-funds-considering-bids-for-enw.thtml

Financeability questions

FQ22. What is your view on our proposed approach to assessing financeability? How should Ofgem approach quantitative and qualitative aspects of the financeability assessment? In your view, what are the relevant quantitative and qualitative aspects?

Ofgem has indicated that it will require companies to conduct financeability analysis on an actual balance sheet basis, in addition to analysis on the notional balance sheet, as part of their RIIO-2 Business Plans. Ofgem's increased focus on testing financeability on an actual balance sheet basis should not provide backstop protections for companies to the detriment of consumers. Ofgem should be clear that that responsibility for addressing financeability issues continues to lie with companies and their investors.

Companies are responsible for addressing financeability issues:

Under the rules of the energy sector, both the regulator and licence holders have a role to play with regards financeability of energy network companies. Ofgem is required to "have regard for the need to secure that licence holders are able to finance the activities which are the subject of obligations on them",[46] in performing their duties. Licence holders must take all appropriate actions to ensure that it maintains an Investment Grade Issuer Credit Rating at all times.[47, 48, 49]

Ofgem's approach in the past, and the weight of UK regulatory precedent, is that the onus to achieve and maintain financeability on the actual balance sheet lies with the companies using a number of tools that are available to them within the price control framework e.g. dividend restrictions, equity injections or in some cases adjustments to capitalisation rates or asset lives used in calculation of depreciation.

Companies' autonomy over their capital structure and raising funds is not known to have resulted in any financial distress under RIIO-1, to date, or under any previous price control set by Ofgem. No company has sought to use the price control disapplication mechanisms that Ofgem introduced explicitly for this purpose. Further, no energy network company has publicly stated that they are experiencing financeability challenges. There are also arrangements in place that would ensure the continuation of services to consumers should a network company ultimately become insolvent.

Companies have a range of tools available to address financeability issues and these tools are sufficient for that purpose. We consider companies should not be allowed to address any financeability issues on the actual balance sheet basis through price control levers, such as decreasing capitalisation rates to increase the pot of fast money leading to higher revenues in the short term (at the expense of lower revenue in the longer term, compared to a higher capitalisation

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46 See https://www.ofgem.gov.uk/publications-and-updates/powers-and-duties-gema

47 See https://epr.ofgem.gov.uk//Content/Documents/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20-%20Current%20Version.pdf

48 See https://epr.ofgem.gov.uk//Content/Documents/Electricity%20transmission%20full%20set%20of%20consolidated%20standard%20licence%20conditions%20-%20Current%20Version.pdf

49 See https://epr.ofgem.gov.uk//Content/Documents/Gas_transporter_SLCs_consolidated%20-%20Current%20Version.pdf

rate). Instead, if financeability problems are identified, solutions can include equity injections or reducing dividends, and diverting money to debt repayments.

Companies can also enhance their financial position through better operational performance: reductions in costs enhance profitability, while financial rewards under incentive mechanisms for sector leading performance can also boost financeability.

Given this range of tools, it should be for companies to resolve, and bear the burden of any resolution to, financeability issues, created by aggressive financing structures and/or inefficient past debt raising programmes.

A role for testing of financeability on the actual balance sheet basis:

We note that Ofwat assess financeability by reference to the notional structure that underpins the cost of capital, and also require Boards to provide assurance that they will be financeable on both a notional and actual basis. We consider that, with appropriate safeguards in place, companies should be required to demonstrate their proposed financing arrangements and projected expenditure are financeable on an actual balance sheet basis as part of the Business Plan process for RIIO-2. We believe that this can be important to enhancing the legitimacy of the price controls by providing confidence to consumers that companies are responsibly financed and that expected dividends and returns to investors are commensurate with the performance of the company and with continuing to maintain overall financeability. It can also enhance the transparency of the sectors' financial arrangements and facilitate better understanding of companies' returns to shareholders and how those returns are linked to the actual performance of the companies.

As financeability for network companies is linked to network companies achieving and maintaining an investment grade credit rating, the information that the network companies should provide could include the ratios that credit rating agencies use in their assessment of companies' financeability, such as those outlined in the table below.

Table 11: Financeability ratios[50]

Gearing (net debt/RAV)
Interest Cover (FFO[51] /cash interest)
Adjusted cash interest cover (FFO + Cash interest expense – Regulatory depreciation + Profiling adjustment) / Cash interest expense
FFO/Net debt
RCF[52]/Net debt

[50] These financeability ratios are used by Moody's and Standard & Poor's
[51] Funds from operation
[52] Retained cash flow

In keeping with Ofgem's expectations for well-justified Business Plans from the network companies,[53] any analysis of these ratios projected over the RIIO-2 period would need to be undertaken using a base case, as well as alternative scenarios where any one or combination of the inflation rate, actual cost of debt, output performance and totex is 'flexed'.

In addition to considering financeability in the short and medium term, it is equally important for Ofgem to consider financial sustainability over the longer term. Proposed financeability adjustments may work for a number of years (e.g. decreasing capitalisation rates), but leave the company exposed in the longer term, which may result in higher costs to consumers. It is for this reason that some credit ratings agencies 'reverse out' any acceleration of revenue into the current price control period by companies. It is therefore important to require companies to provide evidence about their long term financial resilience. In this regard, Ofgem could again require companies to provide information on both an actual and a notional balance sheet basis, noting that this could also act to enhance transparency and legitimacy around the sector. Ofgem could require energy network companies to consider a range of downside scenarios including:

- Totex underperformance
- Cost of any new debt financed above the allowed cost of debt
- Under-delivery against output targets, resulting in a penalty
- Relatively poor performance against output targets compared to peers, resulting in a penalty

Conclusion:
The RIIO-2 price controls must enable a company that is efficiently financed and operated to be financeable, but Ofgem has no such responsibility to enable inefficiently financed or operated companies to achieve financeability, nor to protect companies from risks arising from overly aggressive financial structures.

Consistent with this, Ofgem has always focused on conducting financeability assessments on a notional balance sheet basis, rather than having regard to the financeability of the actual companies. Ofgem's decision to require companies to submit information about their financeability on an actual balance sheet basis for RIIO-2 accordingly represents an important change from Ofgem's approach in the past.

It is imperative that Ofgem's approach does not undermine its wider incentive-based regulatory framework by providing backstop protections to inefficiently financed and operated companies: to do so would be detrimental to consumers' interests and would undermine the legitimacy of the overall price control framework.

We believe, however, that with appropriate safeguards in place it would be appropriate for Ofgem to require companies to conduct financeability tests on an actual balance sheet basis. We consider that this information could enhance transparency and legitimacy in the sector.

[53] For example, see
https://www.ofgem.gov.uk/sites/default/files/docs/2012/02/120217_gdn_initial_assessment_annex.pdf

FQ23. Do you agree with the possible measures companies could take for addressing financeability? Are there any additional measures we should consider?

Some of the proposed financeability adjustments may work for a number of years (e.g. decreasing capitalisation rates, or depreciation rates), but leave the network company exposed in the longer term, which may result in higher costs to consumers.

FQ24. Do you agree with the objectives and principles set out for the design of a cashflow floor?

Yes.

FQ25. Do you support our inclusion of and focus on Variant 3 of the cashflow floor as most likely to meet the main objectives?

We continue to believe that the onus for ensuring financeability should lie with the companies. However, if regulatory measures are required to address financeability, it is essential their impact is NPV-neutral from a consumer perspective. It is also important to ensure that company or network measures do not have a negative impact on long-term financeability.

With respect to the cashflow floor variants, whilst we prefer Variant 3 over the others, since it is less likely to be triggered, we are concerned about the proposed mechanics. In appendix 5, step one assumes that the shortfall is funded by consumers via additional charges on bills from suppliers. However, if this is through short notice changes to SO charges levied on suppliers, then it is likely that the majority of this cost will be unable to be factored into supplier charges and will therefore instead be a loss of profits for suppliers. Due to competitive pressures, those suppliers that faced this loss are unlikely to recoup it when SO rates reduce again to return the shortfall (unless it was returned in proportion to market share at the time of the initial cash call). Ofgem needs to give full consideration to how such an approach would work for suppliers, particularly with respect to any remaining price caps.

It may be worth exploring whether the shortfall could instead be paid for by the other network companies themselves with each network then able to increase use of system charges using normal notice periods to recover the costs from suppliers (and ultimately consumers). Placing the onus onto network companies who can be certain to recoup the cost should result in less risk overall than placing the onus onto supply companies who are unlikely to recoup the cost.

RAV indexation (CPIH) questions

FQ29. What is your view on our proposal for an immediate switch to CPIH from the beginning of RIIO-2 for the purposes of RAV indexation and calculation of allowed return?

FQ30. Is there a better way to secure NPV-neutrality in light of the difficulties we identify with a true-up?

We agree that there should be a move away from RPI. RPI is no longer a formal measure of inflation and so should not be relied upon. We also agree with the proposal for an immediate switch to CPIH from the beginning of RIIO-2. This is a genuinely NPV neutral way to mitigate against any financeability concerns associated with the lower cost of equity for RIIO-2.

On balance, we agree that NPV-neutrality is best secured, in terms of RAV and allowed returns, by a one-off, point-in-time switch from RPI to CPIH, reflecting the expected difference at that time, rather than monitoring the difference over time or truing up for any outturn RPI or wedge values. We consider a true-up would add significant complexity to the regime. We also note that a true-up would be inconsistent with the approaches for the cost of equity and the cost of debt, which also emphasise expectations rather than outturns. Naturally, the size of the adjustment is of critical importance, and we reserve judgement on this.

ESO roles and principles questions:

ESOQ1. Do you agree with our proposal to maintain the current roles and principles framework for RIIO-2?

We agree it is appropriate to maintain the current roles and principles framework for RIIO-2. It is prudent not to make major changes to the Principles[54] until there is evidence to suggest some or all are no longer fit-for-purpose or are driving the wrong behaviours. The Roles and Principles are fundamental elements of the regulatory and incentive scheme for the ESO – they guide how stakeholders set out their expectations of the ESO, shape the Forward Plan and influence how the ESO's performance is assessed. This means it may not be appropriate to change or merge Principles without formally consulting stakeholders.

ESOQ2. Do you agree with our proposals to keep the ESO's code administration, EMR delivery body, data administration, and revenue collection functions in place for RIIO-2? Do you believe that any of these functions (or any other functions) should be opened up to competition, either now or in future?

We agree that, at this stage, there is no compelling evidence to support the delivery of the 'data administration and information provision', 'revenue collection and pass-through' and 'EMR delivery function' functions by another party. We also agree it is prudent to allow the Energy Networks Codes Review[55] to be concluded before making changes to the ESO's responsibilities. This means an appropriate uncertainty mechanism should be included in the ESO's price control if the implementing the Review outcomes requires changes to the ESO's roles, functions, outputs and allowances.

ESOQ3. Do you consider the ESO is best-placed to run early and late competitions?

Based on the evidence presented in the consultation, it is not clear whether the ESO is best-placed to run 'early' and 'late' competitions. For example, it has not been suggested how the perception of bias can be mitigated, which may materially affect the ESO's suitability. It may be possible for arrangements to be implemented that sufficiently mitigate the risk of bias.

Though not proposed in the consultation, the suitability of the ESO to run competitions at the distribution level should be considered, on the basis arrangements that sufficiently mitigate the risk of bias can be implemented. There could be greater perception of bias if network companies are required to run competitions in their 'host' areas. It is not appropriate for network companies

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[54] Ofgem has signalled its intent to make minor changes to the Principles. See: https://www.ofgem.gov.uk/system/files/docs/2019/02/final_consultation_on_changes_to_2019-20_eso_incentives_framework.pdf.

[55] The joint government and Ofgem review of the codes which govern the energy system. See: https://www.gov.uk/government/publications/energy-network-codes-review?utm_source=ad694866-5994-4898-9fa1-0d26d3f1b662&utm_medium=email&utm_campaign=govuk-notifications&utm_content=immediate.

to run competitions to deliver projects while also competing to deliver the same projects. Requiring the ESO to run competitions at the distribution level may be a way of mitigating against the risk of bias. The economies of scale to be derived from the ESO (or another third party) running competitions at the transmission and distribution levels in the electricity system (and potentially for the gas sector) should be considered.

ESOQ4. Do you agree with our proposal to move to a two-year Business Planning cycled price control process for the ESO? If not, please outline your preferred alternative, noting any key features (e.g. uncertainty mechanisms or re-openers) that should be included.

In the short- to medium-term, implementing either the two-year cycle or the twin-track cycle is an appropriate way of ensuring the ESO's price control is sufficiently flexible to account for future uncertainties in the development of the energy system. The full 'reset' of outputs and allowances after two years (with certainty provided for investment spanning multiple planning cycles) or the 'reset' of opex allowances after two years with capex allowances set over a longer period (with appropriate uncertainty mechanisms included in the arrangements) may, pragmatically, provide similar flexibility.

We welcome the ESO being required to develop its Business Plan in the context of its longer-term vision. Given the role the wider industry now plays in the regulation and governance of ESO, the longer-term vision should be influenced by stakeholders. The explicit requirement for Business Plans to be developed in the context of its longer-term vision further embeds the push to deliver against stakeholders' requirements. This complements the requirement on the ESO to demonstrate how the annual Forward Plan supports the long-term vision[56] and for its performance assessment to consider delivery against long-term objectives[57]. This, along with the proposed remuneration model and the evaluative incentive, should provide the ESO with sufficient incentives certainty to plan for the longer term.

It is proposed the current annual regulatory cycle (e.g. development of the Forward Plan) is retained in the next price control. It may be necessary to consider how the annual regulatory cycle and the Business Plan process can be streamlined to ensure the right balance between the regulatory processes and delivery is struck.

ESOQ5. What stakeholder engagement mechanisms should be put in place for the ESO's Business Planning and ongoing scrutiny of its performance? Do you agree with our proposal to maintain, and build upon, the role of the Performance Panel?

The current requirements on the ESO to build stakeholder views into its business planning are reasonable. No firm conclusion about the arrangements for the ongoing scrutiny of the ESO's performance can be drawn since a full regulatory cycle of the new regulatory arrangements has

[56] "The Electricity System Operator Reporting and Incentive Arrangements: Guidance Document"; paragraph 5.6: https://www.ofgem.gov.uk/system/files/docs/2018/03/esori_arrangements_guidance_document.pdf.

[57] "The Electricity System Operator Reporting and Incentive Arrangements: Guidance Document"; paragraphs 3.13-3.14.

not yet been completed. Nevertheless, the transparency brought about the new regulatory regime represents an improvement on the arrangements that existed before.

ESOQ6. Do you agree with our proposed approach of using evaluative, ex-ante incentives arrangements for the ESO?

No firm conclusion about the operation of the evaluative, ex-post arrangements can be drawn since a full regulatory cycle of the new regulatory arrangements has not yet been completed. However, in principle, we support the approach because it encourages the ESO to be more responsive to its stakeholders' requirements and to deliver across the full spectrum of its activities. We note improvements to the assessment arrangements have been proposed[58]. The proposed improvements seem sensible. In addition, we recommend greater clarity on the factors to be considered when assessing performance is provided.

In the current price control, interactions between the evaluative incentive, performance assessment and baseline funding and expectations cannot be fully resolved because of the combined ESO and Transmission Operator. This price control review should result in a common understanding of baseline delivery and funding. It also provides an opportunity for it to be reinforced that the evaluative incentive is meant to reward or penalise performance against objectives instead of funding performance improvements.

> *This is where a decision on financial incentives is made at the end of the year based on an assessment of the ESO's performance against its objectives (which would cover both short and long-term outcomes).*[59]

This should not prevent the ESO from investing to deliver performance improvements. Ofgem previously stated:

> *We would also like to clarify that the ESO should be investing in order to unlock incentive payments, and that the ESO should not be protected from the costs of this investment.*[60]

The proposed remuneration model supports this approach by providing the ESO with discretion to invest on activities not in the baseline to deliver consumer value. The proposed cost disallowance mechanism should encourage the ESO to ensure the incremental expenditure is not demonstrably inefficient. We recommend the cost disallowance criteria are widened to require the ESO to demonstrate stakeholder support for the additional initiatives and expenditure and that the expenditure is justified. Also, costs associated with the gas sector or shared system

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[58] See: https://www.ofgem.gov.uk/system/files/docs/2019/02/final_consultation_on_changes_to_2019-20_eso_incentives_framework.pdf.

[59] "The Electricity System Operator Regulatory and Incentives Framework from April 2018 - Consultation on our minded to decision"; paragraph 2.17: https://www.ofgem.gov.uk/system/files/docs/2017/12/eso_regulatory_and_incentives_framework_from_april_2018.pdf.

[60] "The Electricity System Operator Regulatory and Incentives Framework from April 2018 – Final decision"; paragraph 2.77: https://www.ofgem.gov.uk/system/files/docs/2018/02/policy_decision_on_electricity_system_operator_regulatory_and_incentives_framework_from_april_2018.pdf.

operation costs across the gas and electricity sectors which are disproportionately allocated to the electricity sector should be disallowed.

It has been recognised the EMR incentive scheme expires in 2021. It should be clarified whether it is intended to retain incentives relating to EMR and, if so, whether the mechanism will form part of the evaluative incentive.

In the consultation, it is proposed that the evaluative incentive could be used to drive cost efficiencies. On the basis that the evaluative incentive is meant to reward or penalise overall performance, it is not clear how effective the evaluative incentive can be at driving efficiencies.

ESOQ7. Do you agree that we should continue to apply a single 'pot' of incentives to the ESO, and that this should be a symmetrical positive/negative amount? If not, why not?

In the first instance, a single 'pot' of incentives should continue to apply to the ESO instead of multiple pots for each ESO activity. We are unaware of evidence confirming consumers place greater 'value' on some of the ESO's activities, especially since those activities have not yet been defined. Further, applying the 'pot' equally across the Roles[61] retains focus across the Roles and reduces the risk of consumer value being lost because of the 'boundaries' between activities.

As the evaluative incentive is meant to reward or penalise performance, it is appropriate to retain a two-sided incentive as a means of encouraging the ESO to ensure performance does not fall below baseline expectations. We recognise the unique position of the ESO in electricity system and the significant consumer value it actions could realise. This means upside-only incentive arrangements could be considered, to encourage the ESO to pursue consumer value. However, licence obligations would be required, to protect against performance falling below baseline expectations. Alternatively, an asymmetric incentive with greater upside could be considered.

ESOQ8. Do you agree with our proposed approach to assessing the costs of the ESO under RIIO-2? Do you think we should assess costs on an activity-by-activity basis? How would you go about defining the activity categories? Are there alternative approaches we should consider?

We agree with the proposed approach to assessing the costs of the ESO under RIIO-2. We also agree costs should be assessed on an activity-by-activity basis. This will provide greater transparency of the ESO's internal costs and should help stakeholders assess whether the ESO intends to allocate resources to align with stakeholders' priorities. Additionally, this may help to ensure the ESO does not to seek optimise its costs 'internally' based on the differentials in margins across activities.

Assessing costs on an activity-by-activity basis may also reduce the risk of cross-subsidy across sectors. As of April 2019, the ESO will become a legally-separate entity within the National Grid

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[61] This change has been proposed for the 2019-20 scheme year. See: https://www.ofgem.gov.uk/system/files/docs/2019/02/final_consultation_on_changes_to_2019-20_eso_incentives_framework.pdf.

group but the System Operators (SOs) across the gas and electricity sectors will be operated as a combined function. The gas SO will remain 'integrated' with the Transmission Operator. This creates the risk that expenditure associated with the gas sector which should be funded through National Grid's totex allowances could be allocated to the ESO, which is then funded via the pass-through remuneration model. Assessing costs on an activity-by-activity basis for the ESO should reduce this risk.

ESOQ9. Do you consider the types of cost assessment activities we outline in this chapter are the right ones? Are there additional activities you think we should consider?

We agree costs should be assessed on an activity-by-activity basis. We acknowledge some activities have been proposed in the consultation and agree they could be defined more granularly. We look forward to the output from the next phase of work.

ESOQ10. Do you agree with our proposed remuneration model for the ESO under RIIO-2? Do you think it provides the right incentives for the ESO to deliver value for money for consumers and the energy system? Are there other models you think are better suited?

The proposed remuneration model for the ESO under RIIO-2 is appropriate. The model allows the ESO greater discretion to commit resources, even if expenditure exceeds baseline allowances. It allows the ESO the flexibility to pursue initiatives to unlock consumer value that may not have been anticipated at ahead of the price control, thereby avoiding delaying or not realising additional consumer value. The remuneration model is compatible with the evaluative incentive approach – the ESO has the discretion to invest to unlock performance against the incentive while the incentive rewards or penalises performance instead of funding service improvements. It is necessary to consider whether it is appropriate for the margin(s) to be applied to efficient expenditure above baseline allowances to meet baseline expectations, which was triggered by changes in circumstances.

ESOQ11. Are there any risks associated with our proposed remuneration model that you do not think have been effectively captured and addressed? Do you think that we should put in place any of the mechanisms intended to provide additional security to the ESO outlined in this chapter – e.g. parent company guarantee, insurance premium, industry escrow or capital facility?

The proposed remuneration model does not effectively capture or address the risk of cross-subsidy. As of April 2019, the ESO will become a legally-separate entity within the National Grid group but the System Operators (SOs) across the gas and electricity sectors will be operated as a combined function. Further, the gas SO will remain 'integrated' with the Transmission Operator. This creates the risk that expenditure for the combined SO function cannot be allocated reliably between gas and electricity. This risk could be reduced by extending the cost disallowance mechanism to cover the allocation of costs between gas and electricity.

Clarity should be provided on how the expenditure disallowance mechanism is likely to operate and on the criteria against which expenditure is assessed. We recommend the disallowance mechanism is considered only in extreme circumstances. If the ESO believes the disallowance mechanism is reasonably likely to be employed, then the ESO may be reluctant to commit to spending.

ESOQ12. Do you agree with our proposal relating to remove the cost sharing factor? Can you foresee any unintended consequences in doing so, and how could these be mitigated?

We agree with the proposal to remove the cost sharing factor – this reduces the risk of consumer value being lost by way of the ESO having an incentive to reduce expenditure over delivering consumer value. Removing the sharing factor also reduces the risk of creating a perverse incentive for the ESO to over-forecast expenditure requirements. The proposed cost disallowance mechanism can mitigate somewhat against the risk of the ESO not seeking cost efficiencies where appropriate. However, we do recognise that an efficiency incentive is a desirable. If Ofgem is not confident this can be delivered through the evaluative process, retaining the cost sharing factor should be considered.

ESOQ13. Do you agree with our proposal to introduce a cost disallowance mechanism for demonstrably inefficient costs? What criteria should we apply in considering what constitutes 'demonstrably inefficient'?

We agree with the proposal to introduce a cost disallowance mechanism for demonstrably inefficient costs. The mechanism can mitigate the risk of the ESO not seeking cost efficiencies where appropriate. The mechanism can also mitigate the risk of the ESO inefficiently incurring incremental expenditure above baseline allowances given the proposed remuneration mechanism allows the ESO greater discretion to do so.

The criteria should be widened to cover the allocation of costs between gas and electricity..

Clarity should be provided on how the expenditure disallowance mechanism is likely to operate and on the criteria against which expenditure is assessed. We recommend the disallowance mechanism is considered only in extreme circumstances. If the ESO believes the disallowance mechanism is reasonably likely to be employed then the ESO may be reluctant to commit to spending.

ESOQ14. Do you agree with our proposals to retain an innovation stimulus for the ESO, but tailor aspects of this innovation stimulus to take account of the nature of the ESO business?

We agree an innovation stimulus for the ESO should be retained. It is proposed a new network innovation funding pot that will have a sharper focus on strategic challenges, such as those relating to the energy system transition, should be introduced. This fund may be used to support collaboration within the regulated sectors (whole system projects) if this likely to generate net benefits to network consumers. Given the ESO's unique role in the energy system, it is essential the ESO can participate in projects relating to the strategic challenges.

Chapter 3 questions – Meet the needs of consumers and network users

GDQ2. For each potential output considered (where relevant):

a) Is it of benefit to consumers, and why?

b) How, and at what level should we set targets? (e.g. should these be relative/absolute)

c) What are your views on the design of the incentive? (e.g. reward/penalty/size of allowance)

d) Where we set out options, what are your views on them and please explain whether there are further options we should consider?

Unplanned interruptions average restoration time incentive:

This incentive could be of benefit to consumers. It is meant to drive GDNs to restore gas supply efficiently and effectively following an unplanned interruption. We support the intent of the incentive.

We think there is merit is setting separate targets for MOBs, on the basis MOBs may require an inherently different approach to restoring supply. We recognise there are concerns about data and inconsistencies in reporting between GDNs at a disaggregate interruption level[62], and that targets were revised during RIIO-GD1[63]. We recommend data quality and reporting issues at the disaggregate interruption level are resolved before a financial incentive is set. Otherwise, this creates the risk of windfall gains and losses. Further, benchmarking outputs may be less reliable if those issues exist. Until those issues are resolved, it may be appropriate to introduce a licence condition to obligate the GDNs to ensure performance does not worsen below that achieved during RIIO-GD1.

Once the data quality and reporting issues at the disaggregate interruption level have been resolved, targets should not be set at the level the average performance achieved during RIIO-GD1. This does not embed the levels of performance that have been achieved during RIIO-GD1. Targets should be updated year-on-year so that future annual targets capture revealed performance. It may be necessary to place a ceiling on the baseline duration in each year, so that performance does not deteriorate below the target level at the start of RIIO-GD2.

Emergency response time:

Retaining this licence obligation is of benefit to consumers.

Emergency response and enquiry service:

This proposed licence obligation would be of benefit to consumers because it obligates the gas networks to the ensure emergency response phone line should always be operational to receive calls.

[62] Gas Distribution annex; paragraph 3.172.

[63] "Decision on amendments to reliability (loss of supply) targets for RIIO-GD1": https://www.ofgem.gov.uk/system/files/docs/2018/11/dorset_decisionletter_assessment_final_0.pdf.

Guaranteed Standards of Performance:
GDQ18. Do you support the proposal to make all GSOP payments automatic for RIIO-GD2 and why?

We agree all GSOP payments should be made automatic.

Average restoration time incentive for total unplanned interruptions:
GDQ23. What do you think of the proposed new output based on average restoration time for total unplanned interruptions?

This incentive could be of benefit to consumers. It is meant to drive GDNs to restore gas supply efficiently and effectively following an unplanned interruption. We support the intent of the incentive.

We think there is merit is setting separate targets for MOBs, on the basis MOBs may require an inherently different approach to restoring supply. We recognise there are concerns about data and inconsistencies in reporting between GDNs at a disaggregate interruption level[64], and that targets were revised during RIIO-GD1[65]. We recommend data quality and reporting issues at the disaggregate interruption level are resolved before a financial incentive is set. Otherwise, there is a risk of windfall gains and losses. Further, benchmarking may be less reliable if those issues exist. Until those issues are resolved, it may be appropriate to introduce a licence condition to obligate the GDNs to ensure performance does not worsen below that achieved during RIIO-GD1.

Once the data quality and reporting issues at the disaggregate interruption level have been resolved, targets should not be set at the level the average performance achieved during GD1. This does not embed the levels of performance that have been achieved during RIIO-GD1. Targets should be updated year-on-year so that future annual targets capture revealed performance. It may be necessary to place a ceiling on the baseline duration in each year, so that performance does not deteriorate below the target level at the start of RIIO-GD2.

GDQ25. What are your views on separating interruptions that occur in MOBs into a specific output?

We think there is merit is setting separate targets for MOBs, on the basis MOBs may require an inherently different approach to restoring supply. We recognise there are concerns about data and inconsistencies in reporting between GDNs at a disaggregate interruption level[66], and that targets were revised during RIIO-GD1. We recommend data quality and reporting issues at the disaggregate interruption level are resolved before a financial incentive is set.

[64] Gas Distribution annex; paragraph 3.172.
[65] "Decision on amendments to reliability (loss of supply) targets for RIIO-GD1".
[66] Gas Distribution annex; paragraph 3.172.

Chapter 4 questions – Deliver an environmentally sustainable network
GDQ27. For each potential output considered (where relevant):
a) Is it of benefit to consumers, and why?
b) How, and at what level should we set targets? (e.g. should these be relative/absolute)
c) What are your views on the design of the incentive? (e.g. reward/penalty/size of allowance)
d) Where we set out options, what are your views on them and please explain whether there are further options we should consider?

Shrinkage:
In principle, this incentive should be of benefit to consumers. It is meant to encourage the GDNs to reduce the shrinkage on the network to deliver environmental and wider consumer benefits. While we support the intent of the incentive, we have concerns about how shrinkage is modelled, how targets are set and that GDNs' purchasing strategy may be contributing to market distortions. Also, we have concerns about placing an additional, significant financial incentive against it when much of the activity to address shrinkage is business as usual for the GDNs[67]. Ofgem should consider whether the current incentive 'strength', or even whether placing an incentive on shrinkage reduction, remains appropriate given the concerns we discuss below.

Model assumptions:
We recognise the reliance on the GDNs' model to estimate the targets and actual shrinkage. We have previously raised concerns that potential misallocation of gas volumes between shrinkage and unidentified gas creates the risk of market distortions. Several of the assumptions relied upon in the GDNs' model are outdated and require reassessing given their age. Some of the assumptions have not been reviewed in decades[68]. We are unaware of any evidence to suggest those leakage rates have not changed materially since the tests were conducted. We recommend:

- analysis of the materiality of the potential error associated with the use of outdated assumptions and the cost of reassessment is conducted so SLM improvements can be targeted, and
- a 'lifetime' for each key assumption is agreed with stakeholders so that the industry can be confident that such key assumptions will be reviewed at appropriate intervals.

Target-setting:
A significant financial incentive to encourage shrinkage reductions may not provide benefit to consumers since much of the activity to address shrinkage is BAU. The main driver behind shrinkage reductions over the RIIO-GD1 price control has been the Repex programme. Baseline targets for the GD1 price control were normalised to attempt to take account of the replacement of ageing infrastructure. It is acknowledged it this is very challenging to do. A financial incentive is appropriate only if there is sufficient confidence that the impact of Repex can be isolated. Otherwise, retaining the incentive creates the risk of 'windfall' gains.

[67] Gas Distribution annex; page 59.
[68] For example, see: https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/Joint%20GDN%20Response%20to%20Energy%20UK%20GRG%20Shrinkage%20Study_0.pdf.

Potential market distortions:
A methodology for profiling shrinkage volumes across the year should be developed. GDNs currently assume a 'flat' shrinkage profile i.e. it is assumed an equal amount of gas is lost through shrinkage in each day across the regulatory year. Given shrinkage volumes are influenced by factors that vary across the year (such as system pressures), we suggest a 'flat' shrinkage profile might not reasonably represent the profile of actual losses. This may lead to the misallocation of gas volumes between shrinkage and unidentified gas over shorter timer periods. We recommend a methodology for profiling shrinkage volumes to reasonably represent actual losses is developed.

<u>Decarbonisation of heat:</u>
The proposed approach is appropriate.

GDQ29. What are your views on the RIIO-GD1 outputs that we propose to remove?

The proposed approach is appropriate.

Decarbonisation of heat:
GDQ31. Do you agree with our proposed approaches to funding GDN activities over RIIO-GD2 related to Heat decarbonisation?

The proposed approaches are appropriate.

Chapter 5 questions – Maintain a safe and resilient network:
GDQ34. For each potential output considered (where relevant):
a) Is it of benefit to consumers, and why?
b) How, and at what level should we set targets? (e.g. should these be relative/absolute)
c) What are your views on the design of the incentive? (e.g. reward/penalty/size of allowance)
d) Where we set out options, what are your views on them and please explain whether there are further options we should consider?

<u>Repex:</u>
This output is necessary, to govern the replacement of old and deteriorating gas mains, services and risers. A portion of the Repex programme is driven by the need to ensure gas networks are compliant with HSE safety standards. We welcome the review of arrangements relating to the programme, to ensure efficient delivery from the consumer perspective. This review is being undertaken against the backdrop of allowances for the programme constituting a significant portion of overall totex allowances in RIIO-GD1 and the greatest degree of under-spend arises from Repex. Some of this under-spend is due to different diameter mixes and lay-to-abandon ratios compared to those initially proposed being delivered. There has also been a unit cost 'benefit. We note CEPA's observations in this area in their RIIO1 review:

Ofgem should consider using a workload profile for RIIO-GD2 that accounts for the assumed, rather than actual, repex profile for RIIO-GD1. This would protect consumers from cases where GDNs prioritised lower-cost work in RIIO-GD1 and left the higher-cost work for RIIO-GD2[69]

Asset categorisation:

'Mandatory' repex and 'asset management' repex are useful concepts that can be used to guide how delivery should be funded, whether uncertainty mechanisms are needed and how performance should be measured. Broadly, the 'mandatory' repex programme is volume-based according to HSE requirements while the 'asset management' repex programme is developed largely at the discretion of the GDNs. The boundary between the programmes could be more explicitly considered, according to whether HSE criteria are considered for investment purposes:

- 'Mandatory' repex – assets for which HSE criteria play a role in determining whether investment is undertaken. This includes mandatory decommissioning and decommissioning (or not) according the HSE risk threshold. Services are included because of the relationship with Tier 1 mains.
- 'Asset management' repex – remaining assets.

Our definitions result in Tier 2B mains being reclassified as part of 'mandatory' repex. This is shown in Table 12.

Outputs, funding and uncertainty mechanisms:

In line with our classification, we recommend outputs are 'tightly' defined for assets for which HSE criteria play a role in determining whether investment is undertaken.

- Tier 1: we agree PCDs should be used to define these targets. PCDs clearly link outputs to cost allowances and allow the GDNs to be held accountable for the workloads they will be funded to deliver. We also agree GDNs should be held accountable for delivering the diameter band mixes outlined in their Business Plans.
- Services: it may be appropriate to use PCDs to define these targets if there is sufficient certainty about workloads. If not, a volume driver should be considered.
- Tier 2A: we agree a target should not be set given the uncertainty about workloads
- Tier 2B: it may be appropriate to use PCDs to define these targets if there is sufficient certainty about workloads. If not, a volume driver should be considered.

In instances in which PCDs are used to set targets based on volumes abandoned, Ofgem should consider whether it would be appropriate to provide final allowances according to volumes laid instead of volumes abandoned.

Outputs for assets in the 'asset management' repex may be defined using PCDs or could comprise part of the overall asset health targets.

[69] "Review of RIIO Framework and RIIO-1 Performance"; page 6.

Table 12: 'Repex' programme classifications

Area	Description	HSE criteria in decision-making	Ofgem's proposal - category	Centrica's proposal - category	Ofgem's proposal - funding	Centrica's proposal - funding
Tier 1	Less than or equal to 8 inches in diameter. Must be decommissioned under a 30 year programme.	YES	Mandatory	Mandatory	PCD	PCD
Services			Mandatory	Mandatory	PCD or asset health funding	PCD or volume driver
Tier 2A	Greater than 8 inches to less than 18 inches in diameter, which breach a risk threshold. Must be decommissioned or remediated.	YES	Mandatory	Mandatory	Volume driver	Volume driver
Tier 2B	Greater than 8 inches to less than 18 inches in diameter, which are below a risk threshold. Mains can remain operational, but decommissioning funded if supported by CBA.	YES	Asset Management	Mandatory	PCD or asset health funding	PCD or volume driver
Tier 3	Greater than 18 inches in diameter. Mains can remain operational, but decommissioning funded if supported by CBA.	NO	Asset Management	Asset Management	PCD or asset health funding	PCD or asset health funding
Tier 3, Iron mains >30m, Elective steel pipes<=2", Risers, Steel pipes>2"		NO	Asset Management	Asset Management	PCD or asset health funding	PCD or asset health funding

NTS exit capacity:

This incentive is not of benefit to consumers. We previously highlighted flaws in the existing arrangements. We acknowledge elements of the proposals address our concerns about existing arrangements. For example, it is proposed that advance capacity price estimates should be replaced with final offtake capacity prices when calculating rewards and penalties. However, other developments such as the review and potential rebasing of baseline obligated capacities (which may result in opportunities to utilise 'flexible' capacity) and new arrangements arising out of the Gas Transmission Charging Review are likely to render the incentive mechanism redundant and of no benefit to consumers.

Gas holder demolitions:
This output is of benefit to consumers. It is meant to allow the GDNs to be held accountable for delivery. We support the intent.

Network Asset Risk Metric:
Our views on network asset risk metrics are set out in the responses to questions CSQ19-26.

Cyber resilience:
Our views on cyber resilience are set out in the responses to questions CSQ33-34.

Physical security:
Our views on physical security are set out in the responses to questions CSQ28-30.

GDQ36. What are your views on the RIIO-GD1 outputs that we propose to remove?

Sub-deducts off risk:
This output is no longer needed since it is expected the work programme will be completed by the end of RIIO-GD1.

Mains replacement level of risk removed:
The Mains Replacement Level of Risk Removed output is no longer needed since alternative arrangements have been proposed.

Repex:
GDQ37. What are your thoughts on our proposals for Tier 1 outputs?

We agree PCDs should be used to define these targets. PCDs clearly link outputs to cost allowances and allows the GDNs to be held accountable for the workloads they will be funded to deliver. We also agree GDNs should be held accountable for delivering the diameter band mixes outlined in their Business Plans.

GDQ38. Do you think we should set an output for replacing non-PE services?

We agree an output for replacing non-PE services should be set because of the relationship with Tier 1 mains. It may be appropriate to use PCDs to define these targets if there is sufficient certainty about workloads. If not, a volume driver should be considered.

GDQ39. Do you think we should set outputs for asset maintenance repex activities?

Outputs for assets in the 'asset management' repex may be defined using PCDs or could comprise part of the overall asset health targets. There may be greater flexibility in how outputs for asset maintenance repex activities since, by definition, GDNs have greater discretion how these activities are delivered since investment decisions are not linked to HSE criteria.

GDQ40. What are your thoughts on not including Mains Replacement Level of Risk Removed, GIBs and fractures as output measures for RIIO-GD2?

The Mains Replacement Level of Risk Removed output is no longer needed since alternative arrangements have been proposed. Ofgem should consider whether removing outputs relating to GIBs and fractures could encourage behaviours that are not in consumers' interests.

GDQ41. Do you agree with our proposed approach to repex uncertainty mechanisms?

A volume driver may be used to provide funding for the replacement of Tier 2B if there is insufficient certainty about workloads. We agree a re-opener should be included so that allowances and outputs can be adjusted in response to changes in HSE policy.

NTS exit capacity:

GDQ42. What are your views on our proposal to use final offtake capacity prices rather than T-3 offtake capacity price estimates in the calculation of incentive rewards and penalties in RIIO-GD2?

We do not believe the NTS Exit Capacity incentive has provided any benefit to consumers. We previously highlighted flaws in the existing arrangements. We acknowledge elements of the proposals address some our concerns about existing arrangements. For example, it is proposed that advance capacity price estimates should be replaced with final offtake capacity prices when calculating rewards and penalties. If the incentive is to be retained, it is also critical that the costs included for incentive performance purposes include all exit capacity costs incurred (e.g. including flexible capacity costs). Otherwise, networks receive rewards simply by moving costs out of the areas included for assessing performance, which would still be recovered through the pass-through mechanism.

However, we remain of the view that the incentive is not in consumers interests. It is important to note that the 'cost savings' achieved by GDNs in RIIO-1 are only notional, since the reduced revenue recovered from GDNs by National Grid Transmission have instead been recovered from consumers through the TO exit commodity charge i.e. there has been no reduction in overall cost to the consumer to offset the expected £115m rewards (0.3% RoRE impact) to be received by the GDNs in RIIO-1. Further, other developments such as the review and potential rebasing of baseline obligated capacities and new arrangements arising out of the Gas Transmission Charging Review are likely to render the incentive mechanism redundant and of no future benefit to consumers.

Chapter 6 questions – Cost assessment

GDQ47. Do you agree with our proposal for implementing symmetrical adjustments for regional or company specific factors?

We agree a high evidential bar should be set for accepting any cost adjustment claims and, by default, symmetrical adjustments should be considered, to reduce the risk of consumer detriment. The proposed approach to implementing symmetrical adjustments is appropriate.

Chapter 7 questions – Uncertainty mechanisms:

General uncertainty mechanism questions

GDQ48. What are your views on the proposed uncertainty mechanisms and their design?

Smart Meters rollout costs:

At this stage, there is sufficient uncertainty about the level of funding for GDNs to support the Smart Meters Implementation Programme. We recommend a volume driver, based on efficient unit costs, is included to allow allowances to adjust in response to the level of GDN activity.

Repex – HSE policy changes:

This mechanism should be included, so that allowances and outputs can be adjusted in response to changes in HSE policy.

Heat policy:

This mechanism should be included. A significant development of central government policy in this area may necessitate changes to GDNs' outputs and allowances.

GDQ50. What are your views on the RIIO-GD1 uncertainty mechanisms we propose to remove?

Agency (Xoserve) costs:

This uncertainty mechanism should be removed since Xoserve's funding, governance and ownership arrangements have been confirmed.

Review of the Non Gas Fuel Poor Network Extension Scheme:
This uncertainty mechanism should not be removed. Government decisions on the future of heat are due during the RIIO-2 period. Retaining the uncertainty mechanism would allow a review of the Scheme, if retained, to ensure it remains compatible with policy objectives.

Changes to charging boundary:
This uncertainty mechanism should be removed if the uncertainty it was meant to accommodate no longer exists.

Large load connection costs:
This uncertainty mechanism should be removed if the uncertainty it was meant to accommodate no longer exists.

Innovation Rollout Mechanism:
This uncertainty mechanism should be removed.

Appendix 5 - Gas Transmission Questions

Chapter 3 questions – Meet the needs of consumers and network users
GTQ4. For each potential output considered (where relevant):
a) Is it of benefit to consumers, and why?
b) How, and at what level should we set targets? (eg should these be relative/absolute).
c) What are your views on the design of the incentive? (eg reward/penalty/size of allowance).
d) Where we set out options, what are your views on them and please explain whether there are further options we should consider.

Quality of demand forecasts:
It is not clear whether this incentive will be of benefit to consumers. It should be expected that an efficient and competent network will produce accurate forecasts. As such, we consider this to be a baseline activity. It is not clear whether the current levels of performance create a defect and whether the defect causes consumer detriment. It is appropriate for consumers to fund improvements in the accuracy of the demand forecasts if the improvements generate at least equivalent consumer benefit. Ofgem should consider the extent to which the generality of consumers and NTS users would benefit from the improvements, to determine whether the incentive should be retained.

Maintenance - Use of Days and Changes schemes:
The Maintenance incentive has been of benefit to NTS users during RIIO-GT1. It has encouraged NGGT to adopt a more coordinated approach to maintenance planning, taking NTS users into account.

We acknowledge the levels of performance achieved during RIIO-GT1, particularly relating to the 'Change' scheme. It is appropriate to introduce penalty-only arrangements for the 'Change' scheme since Advice Notices (which are advance agreements between consumers and the System Operator) can be used. At this stage, it is unclear whether penalty-only arrangements for the 'Days' scheme is preferable, based on the evidence presented in the consultation. An alternative to the proposal would be to:

- Introduce a licence obligation on NGGT to ensure continuity of supply for those connections at which remote valve operations can be carried out without disruption.
- Retain the two-sided incentive but focus it on those connections at which remote valve operations cannot be carried out without disruption.

Entry and Exit Capacity Constraint Management:
In principle, the Entry and Exit Capacity Constraint Management (CCM) incentive should be of benefit to consumers. It is meant to encourage NGGT to optimise the costs of managing network constraints. We agree with the intent of the incentive.

We highlight the significant interrelationships with other elements of the price control framework and other policy areas, which are likely to have an impact on the design and operation of the CCM incentive. These include:

- Review of the levels of obligated entry and exit capacities
- Review of approach to selling unused capacity
- Gas transmission charging review

The combined impact of the above factors raises concerns about the ability to set robust targets. The extent to which NGGT will be required and the approach NGGT takes to manage constraints could materially change. Peak demand continues to reduce and flow patterns across the network have been changing. NTS user behaviour, which could affect flow patterns, could be affected by changes to market arrangements such as network charging, capacity purchases and capacity substitution. Additionally, the fact that the incentive in RIIO-GT1 was calibrated around the risk of a high-impact low-probability events suggests it may not be straightforward to capture revealed performance.

On balance, we think retaining a two-sided financial incentive is preferable since removing the incentive may lead to worse consumer outcomes. However, careful consideration should be given to the calibration and the strength of the incentive and how in-period targets can be adjusted to capture revealed performance.

GTQ10. Does NGGT's forecasts of demand provide a service that is valued by consumers and network users? Please explain why.

The demand forecasts produced by NGGT do not provide material value to our business. We are unable to comment on the extent to which they are used or are valued by other stakeholders.

GTQ11. Should gas consumers pay for NGGT to produce accurate demand forecasts? What is the value for consumers from increased accuracy?

It should be expected that an efficient and competent network will produce accurate forecasts. As such, we consider this to be a baseline activity. It is appropriate for consumers to fund improvements in the accuracy of the demand forecasts if the improvements generate at least equivalent consumer benefit. Ofgem should consider the extent to which the generality of consumers and NTS users would benefit from the improvements, to determine whether the incentive should be retained.

Chapter 4 questions – Deliver an environmentally sustainable network
GTQ13. For each potential output considered (where relevant):
a. Is it of benefit to consumers, and why?
b. How, and at what level should we set targets? (e.g. should these be relative/absolute).
c. What are your views on the design of the incentive? (e.g. reward/penalty/size of allowance).

d. Where we set out options, what are your views on them and please explain whether there are further options we should consider.

Compressor Emissions (IED and MCP Directives):

This output, and its construction, are of benefit to consumers. Consumers will be required to fund NGGT to undertake investment to achieve compliance with the various environmental regulations. During the 2018 reopener window, it was deemed too much uncertainty about outputs and the level of expenditure remained to allow NGGT to retain the ex-ante allowances[70]. The ex-ante funding was removed and it was stated funding would be considered as part of the RIIO-GT2 price control review[71].

We support the proposal to require NGGT to develop a Compressor Emissions Compliance Strategy. This should help identify the solutions that are likely to result in the greatest consumer value and the associated efficient levels of expenditure. We agree PCDs should be used to hold NGGT accountable for successful delivery and an uncertainty mechanism should be included to allow outputs and allowances to be adjusted when better information becomes available.

We acknowledge there has been ambiguity during the RIIO-GT1 price control about what NGGT was required to deliver and how NGGT could confirm delivery in line with requirements. This price control review presents an opportunity for unambiguous deliverables to be defined. We support deliverables being defined according to outcomes rather than specific outputs (except when circumstances require specific outputs) that allows NGGT discretion to invest to deliver the greatest consumer benefits. Defining deliverables according to outcomes also allows networks the opportunity to innovate and, potentially, deliver greater consumer benefit, compared to defining specific outputs. As such, we recommend PCDs are specified according to Option 2 and compliance is assessed according to Option 2B.

GHG emissions (Venting):

The GHG emissions incentive is likely to be of benefit to consumers. The incentive is meant to encourage NGGT to achieve the efficient level of emissions reduction by taking the cost of GHG emissions into account when deciding whether to depressurise compressor units. We agree with the intent of the incentive and support NGGT being encouraged to achieve the efficient level of emissions reduction.

We agree the downslide-only incentive should be maintained since it is required NGGT should proposed a target that represents the reflect an efficient level of GHG venting. That target should be supported be stakeholders since it should be agreed by the User Group and the independent Challenge Group. We acknowledge concerns about the ability to set robust targets. However, reducing the strength of the incentive or applying a floor could mitigate those concerns.

70 "RIIO-T1: Our decision on National Grid Gas Transmission's application under the Industrial Emissions Costs reopener"; pages 1-2 : https://www.ofgem.gov.uk/system/files/docs/2018/09/industrial_emissions_costs_decision.pdf.

71 "RIIO-T1: Our decision on National Grid Gas Transmission's application under the Industrial Emissions Costs reopener"; pages 14.

NTS shrinkage:

The NTS shrinkage incentive could be of benefit to consumers, because it meant to encourage NGGT to minimise the cost of shrinkage. We agree with the intent of the incentive and support NGGT being encouraged to minimise this cost.

It is proposed that the two-sided incentive is retained. However, concerns have been raised about the calibration of targets and the extent to which shrinkage NGGT's control. We recommend the proposal is reviewed if confidence in the target-setting process (to avoid windfall gains or losses) is achieved or it cannot be confirmed that shrinkage is within NGGT's control.

Low carbon energy systems and decarbonisation of heat:

We agree that, at this stage, it may not be possible to define outputs. However, as a matter of course, low carbon energy systems and decarbonisation should be a fundamental theme upon which NGGT's Business Plan is based.

We recognise that, in line with the Clean Growth Strategy, government is due to decide on the long-term future of heat in the first half of the 2020s. The Heat Policy Reopener proposed for the gas distribution price control should be considered for the gas transmission price control. A significant development of central government policy in this area may necessitate changes to NGGT's outputs and allowances.

GTQ16. We welcome views on whether further regulatory mechanisms are needed to drive NGGT to be more proactive in reducing its impact on the environment and contributing to the transition to the low carbon energy system.

The Heat Policy Reopener proposed for the gas distribution price control should be considered for the gas transmission price control. A significant development of central government policy in this area may necessitate changes to NGGT's outputs and allowances.

NTS Shrinkage:

GTQ17. Do you think that the 'compressor fuel use' element of the shrinkage incentive should be included within NGGT's baseline Totex allowance? To what extent do you think elements of shrinkage are within the control of National Grid Gas

To the extent that NGGT can control expenditure on this element of shrinkage, it may be appropriate to include it within NGGT's baseline totex allowance. If it is deemed expenditure on the elements of shrinkage is not sufficiently controllable, costs should be passed through to consumers and the incentive mechanism discontinued. Retaining the incentive mechanism if expenditure on the elements of shrinkage is not sufficiently controllable risks creating windfall gains or losses.

Opportunity to propose bespoke outputs:
GTQ19. Do you think we should consider proposals from NGGT for additional outputs and incentives to support our environmental objectives?

Proposals from NGGT for additional outputs and incentives should be considered. The proposals should be accepted if it is assessed they are demonstrably likely to provide consumer benefit and do not overlap other areas of the proposals.

Chapter 5 questions – Maintain a safe and resilient network
GTQ21. For each potential output considered (where relevant):
a. Is it of benefit to consumers, and why?
b. How, and at what level should we set targets? (e.g. should these be relative/absolute).
c. What are your views on the design of the incentive? (e.g. reward/penalty/size of allowance).
d. Where we set out options, what are your views on them and please explain whether there are further options we should consider.

Asset Resilience:
Our views on asset resilience are set out in the responses to questions CSQ19-26.

Safety:
We agree it is not necessary to include a formal price control output or delivery incentive since NGGT's performance against its statutory obligations are monitored and enforced by the HSE.

Network Capability Assessment
We welcome the proposed approach to Network Capability and believe it is benefit to consumers. It is important that network investment aligns with the changing needs of consumers and NTS users and is efficient. It is not ideal that, in some instances, consumers are required to fund capacities that could be above efficient levels. It is also important to reduce the risk of the inefficient allocation of costs between end consumers and other NTS users.

Capacity obligations set at efficient levels should reduce the risk of distorting other elements of the regulatory framework such as the Capacity Constraint Management incentive and the 1-in-20 peak day gas demand obligation. Additionally, capacity obligations set at efficient levels should reduce the risk of distorting market arrangements such has capacity bookings and 'user commitments'. Nevertheless, care should be taken to ensure the outcomes of the network capability review do not result in artificial network constraints being created. This would introduce inefficiency.

Network Capability Target:
The Network Capability Target is of benefit to consumers since network capability ultimately facilitates the flow of gas across the transmission network and is fundamental to NGGT's investment plans. We agree it is appropriate to treat the target as a licence condition since is

network capability is crucial for efficient market operation. We also agree PCDs should be used to hold NGGT accountable for the successful delivery of large discrete investment projects.

The requirement for NGGT to review current network capability and propose levels of obligated baseline entry and exit capacities will provide inputs into the target-setting process. Ofgem should reserve the right to alter baseline obligated entry or exit capacities beyond NGGT's proposals if it is deemed NGGT's proposal could cause consumer detriment.

Maintain 1:20 demand capability:
Retaining this obligation is of benefit to consumers since it the primary security of supply standard that NGGT must meet as the operator of the NTS.

Network Asset Risk Metrics:
Our views on network asset risk metrics are set out in the responses to questions CSQ19-26.

Cyber resilience:
Our views on cyber resilience are set out in the responses to questions CSQ33-34.

Physical security:
Our views on physical security are set out in the responses to questions CSQ28-30.

Safety:
GTQ24. Do you have views on whether the proposed approach on safety is appropriate for RIIO-GT2?

The proposed approach is appropriate.

Network capability:
GTQ25. Do you agree with our assessment of the problems with the current arrangements, and how these problems can lead to consumer detriment?

We welcome the proposed approach to Network Capability. It is important that network investment aligns with the changing needs of consumers and NTS users and is efficient. It is not ideal that, in some instances, funding continues to be provided for capacities that could be above efficient levels. It is also important to reduce the risk of the inefficient allocation of costs between end consumers and other NTS users. Efficient capacity levels should be assessed so as to reduce the risk of distorting other elements of the regulatory frameworks for gas networks such as the Capacity Constraint Management incentive, 1-in-20 peak day gas demand obligations and the Exit Capacity Incentive.

The proposed principles for the network capability review are an appropriate starting point. We suggest the following principle is included:

- Physical capability should be based on a range of factors relating to the operation of the NTS including operating margins, network pressures and flexibility.

Care should be taken to ensure the outcomes of the network capability review do not result in artificial network constraints being created. This would introduce inefficiency.

NGGT should not be allowed to recover revenue from consumers and NTS users for investment that has not been committed and is not needed. We welcome the opportunity to meet with you to discuss examples of where this may be currently happening.

GTQ26. Do you agree with our proposal to require NGGT to carry out an initial network capability assessment and submit the results as part of its Business Plan?

We agree NGGT should be required to carry out an initial network capability assessment and submit the results as part of its Business Plan. This assessment should help Ofgem and stakeholders understand whether NGGT's proposed investment plan is efficient.

GTQ27. Do you agree that if baseline obligated entry or exit capacities are found to be at inappropriately high levels, we should consider revising them downwards in line with NGGT's proposals?

We agree baseline obligated entry or exit capacities should be revised downwards if they are found to be at inappropriately high levels, and allowances should be reduced where relevant. It is not appropriate to require consumers and NTS users to continue to fund capacities that are not needed. Changes to baseline obligated capacities could reduce the risk of the inappropriate allocation of costs between consumers and other NTS users. Ofgem should reserve the right to alter baseline obligated entry or exit capacities beyond NGGT's proposals if it is deemed NGGT's proposal could cause consumer detriment. Nevertheless, care should be taken to ensure artificial network constraints are not created. This would introduce inefficiency.

Arrangements for accessing unsold capacity:
GTQ28. Do you agree with our proposal to require NGGT to review the arrangements for accessing unsold capacity?

We agree NGGT should be required to review the arrangements for accessing unsold capacity. This review could lead to the more efficient use of the transmission infrastructure. We recommend NGGT is required to formally consult on its proposals and Ofgem should formally direct whether the revised arrangements are implemented, given the potential commercial impact on consumers and NTS users.

GTQ29. Do you agree with our proposed scope for the review? Are there other aspects of access that should be reviewed at the same time?

The proposed scope of the review is appropriate. Particularly, we welcome the review of the appropriateness of user-commitment requirements. This element of the review should specifically consider whether NTS users should continue to be tied to 'user commitments' if the additional capacity can be provided via substitution and network investment to satisfy requests for additional capacity has not been committed. We welcome the opportunity to meet with you to discuss examples of where this may be currently happening.

Chapter 7 questions – Uncertainty mechanisms
General uncertainty mechanism questions
GTQ35. What are your views on the proposed uncertainty mechanisms and their design?

The proposed uncertainty mechanisms are appropriate.

In our responses to questions CSQ28-30 and CSQ33-34, we recommend the scope of the Physical Security and Cyber Resilience reopeners is extended to accommodate changes in outputs and allowances that are not driven by changes in government policy.

We support the introduction of the Incremental Capacity reopener. Following the transmission network capability review, it is expected obligated entry and exit capacities will more closely align with consumers' and NTS users' needs over RIIO-GT2. This means the need for funding for incremental capacity during RIIO-GT2 should be highly uncertain. It is unnecessary to maintain the obligation on NGGT to maintain the Generic Revenue Driver Methodology since ad-hoc requests for funding for incremental capacity will be individually scrutinised. If funding is provided, Ofgem should also consider whether NTS users should continue to be tied to 'user commitments' if the need for incremental capacity goes away or the need can be satisfied without additional network investment.

GTQ36. Are there any additional mechanisms that we should be considering across the sector? If so, how should these be designed

The Heat Policy Reopener proposed for the gas distribution price control should be considered for the gas transmission price control. A significant development of central government policy in this area may necessitate changes to NGGT's outputs and allowances.

GTQ37. What are your views on the RIIO-GT1 uncertainty mechanisms we propose to remove?

One-off Asset Health Costs (Feeder 9):

This uncertainty mechanism should be removed because a decision on funding for the replacement of the Feeder 9 pipeline under the River Humber has been made[72]. Further, the use of Price Control Deliverables, in combination with other uncertainty mechanisms if needed, allows for outputs and allowances to be set during RIIO-GT2 in cases in which there is not sufficient certainty of the outputs and/or allowances during the price control review.

Network flexibility:

This mechanism is not needed because the review of baseline obligated entry and exit capacities should result in levels that are appropriate for the duration of RIIO-GT2.

Quarry and Loss Development:

This mechanism should be retained but refocussed exclusively on material one-off claims. During the 2018 reopener window, the discrepancy between the Final Proposals document and NGGT's licence and Price Control Financial Model was highlighted. The GT1 Final Proposals document stated this reopener should be focussed only on material one-off claims but baseline ex-ante allowances were not provided in NGGT's settlement[73].

As a part of its 2018 reopener application, NGGT requested funding for a material one-off claim relating to 'Quarry C'. Funding was not provided as it was deemed unlikely that NGGT would incur any costs during GT1[74]. It was also decided that "*…NGGT can apply for appropriate funding as part of future price control reviews if it believes that any works will be necessary…*"[75]. Ex-ante funding should be provided only if it is confirmed a liability has arisen. If not, a reopener that allows NGGT to apply for funding during GT2, that can be triggered only when the liability is confirmed, is appropriate.

Agency (Xoserve) costs:

This uncertainty mechanism should be removed since Xoserve's funding, governance and ownership arrangements have been confirmed.

Innovation Rollout Mechanism:

This uncertainty mechanism should be removed.

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[72] "RIIO-T1 reopener: One-off Asset Health Costs (Feeder 9)": https://www.ofgem.gov.uk/system/files/docs/2018/09/one-off_asset_health_costs_decision.pdf.

[73] "RIIO-T1 Reopener Consultation - Quarry and Loss Development Claims Costs"; paragraph 1.7: https://www.ofgem.gov.uk/system/files/docs/2018/08/quarry_and_loss_nggt_consultation_document_ofgem_public_version_-_may_2018.pdf.

[74] "RIIO-T1 Reopener Consultation - Quarry and Loss Development Claims Costs"; paragraph 2.33.

[75] "RIIO-T1: Our decision on National Grid Gas Transmission's application under the Quarry and Loss Development Claims Costs reopener"; page 5: https://www.ofgem.gov.uk/system/files/docs/2018/09/quarry_and_loss_development_costs_decision.pdf.

ETQ2. For each potential output considered (where relevant):
a) Is it of benefit to consumers, and why?
b) How, and at what level should we set targets? (e.g. should these be relative/absolute)
c) What are your views on the design of the incentive? (e.g. reward/penalty/size of allowance)
d) Where we set out options, what are your views on them and please explain whether there are further options we should consider?

Timely connections:
This output is likely to be of benefit to network users. The licence obligation and penalty-only incentive are meant to encourage the TOs to play their role in the connections process in a timely manner. We support the intent of the licence obligation and penalty-only incentive.

We agree the licence obligation and penalty-only incentive should be retained. We also agree the penalty mechanism should be extended to include NGET. All TOs should be subject to the same obligations given the separation of the ESO within the National Grid group as of April 2019.

We agree it would be beneficial to develop a mechanism that measures and allows the quality of the connection offers and associated engagement with stakeholders to be compared. Introducing a formalised connections survey component as a part of the Stakeholder Satisfaction Output is appropriate. Given the increasing number of requests for connections at the distribution level that rely on assessments that the transmission level, Ofgem should consider how the licence obligation, incentive and survey component can be extended to accommodate these types of connections.

Energy Not Supplied:
In principle, we agree this incentive is of benefit to consumers. The incentive is meant to encourage the TOs to consider short-term operational risk to deliver a higher level of reliability above the minimum standards required by SQSS, where it is good value for consumers. We support the intent of the incentive.

We acknowledge the high levels of performance across all three TOs that has been sustained over the RIIO-ET1 price control. This means Ofgem should consider whether any further increases in reliability are efficient and can be delivered by the TOs. These considerations should guide the design and structure of the incentive. Ofgem should also consider whether there are any interrelationships between levels of reliability and system balancing actions taken by the ESO i.e. to what degree are ESO actions responsible for the level Energy Not Supplied.

Timely Connections Output:

ETQ15. Do you have any views on whether we should retain the RIIO-ET1 Timely Connections Output (which applies to the connection offer stage) for RIIO-ET2, including the penalty rate, and extend it to NGET?

This output is likely to be of benefit to network users. The licence obligation and penalty-only incentive are meant to encourage the TOs to play their role in the connections process in a timely manner. We support the intent of the licence obligation and penalty-only incentive.

We agree the licence obligation and penalty-only incentive should be retained. We also agree the penalty mechanism should be extended to include NGET. All TOs should be subject to the same obligations given the separation of the ESO within the National Grid group as of April 2019.

ETQ16. Do you have any views on options for capturing the quality of the overall connections process through our stakeholder engagement proposals, for example through the use of a survey?

We agree it would be beneficial to develop a mechanism that measures and allows the quality of the connection offers and associated engagement with stakeholders to be compared. Introducing a formalised connections survey component as a part of the Stakeholder Satisfaction Output is appropriate. Given the increasing number of requests for connections at the distribution level that rely on assessments that the transmission level, Ofgem should consider how the licence obligation, incentive and survey component can be extended to accommodate these types of connections.

ETQ17. Are there any alternative options for capturing the quality of the overall connection process, not identified in this consultation document, which we should be considering?

Given the increasing number of requests for connections at the distribution level that rely on assessments that the transmission level, Ofgem should consider how survey component can accommodate these types of connections.

Energy Not Supplied:

ETQ19. Do you have any views on whether we should retain the ENS incentive, and whether we should retain it as a positive reward mechanism, or move towards a penalty-only scheme? What impact could the move to a penalty-only mechanism have on TO decision-making and behaviours? Please evidence.

We acknowledge the high levels of performance across all three TOs that has been sustained over the RIIO-ET1 price control. This means Ofgem should consider whether any further increases in reliability are efficient and can be delivered by the TOs. These considerations should guide the design and structure of the incentive. Ofgem should also consider whether there are any interrelationships between the higher level of reliability this incentive is meant to encourage and system balancing actions taken by the ESO. For example, Ofgem should consider whether system balancing actions taken by the ESO affect energy not being supplied and, therefore, affects the TOs performance.

Chapter 4 questions – Deliver an environmentally sustainable network

ETQ30. For each potential output considered (where relevant):

a) Is it of benefit to consumers, and why?

b) How, and at what level should we set targets? (e.g. should these be relative/absolute)

c) What are your views on the design of the incentive? (e.g. reward/penalty/size of allowance)

d) Where we set out options, what are your views on them and please explain whether there are further options we should consider?

<u>Environmental considerations embedded in business plans (incl. for example BCF, losses and SF6):</u>

This is likely to be of benefit to consumers and stakeholders since TOs will be required to more explicitly outline how they will use allowances to deliver better environmental performance.

<u>Annual environmental performance reporting (incl. BCF and losses):</u>

This is likely to be of benefit to consumers and stakeholders since TOs will be required to demonstrate progress against initiatives to deliver better environmental performance as outlined in their Business Plans.

<u>Sulphur hexafluoride (SF6) and other IIG leakage:</u>

This incentive is likely to be of benefit to consumers. The incentive is meant to fund initiatives that are likely to reduce the leakage of these gases. We support the intent of the incentive.

In principle, we support the two-sided incentive being retained. This is on the basis that the TOs demonstrate stakeholder support for the baseline targets, Ofgem assesses the baseline targets to represent an efficient level and baseline allowances are provided to deliver the baseline targets. The financial incentive will allow TOs to deliver even greater reductions in leakage if it is efficient to do so. We agree targets should be set to mitigate the risk of a double reward and all TOs companies should use a consistent methodology for measuring and reporting leakage.

<u>Mitigating visual amenity impacts in designated areas:</u>

If the scheme is retained, it is essential the willingness to pay (WTP) analysis is updated. in RIIO-ET1, the amount of funding available was linked to the mean WTP estimates in 2012 National Grid study[76]. The study refers to survey respondents' concerns about affordability[77]. We would expect that concerns about affordability are as least as much an issue as in the period in which the National Grid study. As such, it should be carefully considered whether mean or median WTP estimates are a sufficiently high threshold on which to linked to amount of funding in RIIO-ET2. It

[76] "Consumer Willingness to Pay research"; paragraph 8: https://www.nationalgrid.com/sites/default/files/documents/NationalGridWTPreport.pdf.

[77] "Consumer Willingness to Pay research"; paragraphs 24-26.

is also important that the amount of funding that might be made available in ET2 is considered in the context of other areas of expenditure on transmission infrastructure.

If high value mitigation projects are to be delivered via the 'baseline' RIIO-ET2 framework, we agree they should be classified as PCDs. This allows TOs to be held accountable for successful delivery. We recommend a reopener is attached to the PCDs so that outputs and allowances can be adjusted if alternative solutions, which are not the result of genuine innovation, are identified.

It should be considered whether high value mitigation projects should be delivered via the competition mechanism. We note the project reducing visual amenity impacts in the Dorset Area of Outstanding Natural Beauty, for which funding was awarded in 2018, satisfies the 'high value' criterion for the 'late' competition model. National Grid will be allowed to recover £116m of expenditure allowances[78]. Using 'early' competition to deliver visual mitigation projects could result in solutions being brought forward that represent better consumer value.

Additional contribution to low carbon transition:

An option for the TOs to develop bespoke ODIs with stakeholders for delivering an additional contribution to the low carbon transition should be introduced. This could allow outputs not identified in the consultation to be considered. TOs developing bespoke ODIs with stakeholders should not mean they will automatically introduced. There remains an obligation on Ofgem to assess whether implementing the ODI is appropriate and is likely to be of benefit to consumers.

ETQ32. What are your views on the RIIO-ET1 outputs that we propose to remove?

Environmental Discretionary Reward:

We agree the Environmental Discretionary Reward because of the overlapping objectives with other elements proposed for the RIIO-ET2 price control.

ETQ35. We welcome views on the option of an annual reporting framework to increase transparency of the transmission networks' impact on the environment.

We agree an annual reporting framework to increase transparency of the transmission networks' impact on the environment should be introduced. The reporting framework would require TOs to demonstrate progress against initiatives to deliver better environmental performance as outlined in their Business Plans.

[78] "Determination on National Grid's proposal for reducing visual amenity impacts in the Dorset Area of Outstanding Natural Beauty"; page 1: https://www.ofgem.gov.uk/system/files/docs/2018/11/dorset_decisionletter_assessment_final_0.pdf

Potential for bespoke ODIs around the low carbon transition:

ETQ36. We welcome views on whether we should introduce an option for the TOs to develop bespoke ODIs with stakeholders for delivering an additional contribution to the low carbon transition.

An option for the TOs to develop bespoke ODIs with stakeholders for delivering an additional contribution to the low carbon transition should be introduced. This could allow outputs not identified in the consultation to be considered. TOs developing bespoke ODIs with stakeholders should not mean they will automatically introduced. There remains an obligation on Ofgem to assess whether implementing the ODI is appropriate and is likely to be of benefit to consumers.

In principle, we support the two-sided incentive being retained. This is on the basis that the TOs demonstrate stakeholder support for the baseline targets, Ofgem assesses the baseline targets to represent an efficient level and baseline allowances are provided to deliver the baseline targets. The financial incentive will allow TOs to deliver even greater reductions in leakage if it is efficient to do so. We agree targets should be set to mitigate the risk of a double reward and all TOs companies should use a consistent methodology for measuring and reporting leakage.

Electricity losses from the transmission network:

ETQ43. Do you have any views on the proposed approach for integrating any losses reporting requirements into the proposed Business Plan and annual public reporting framework?

The proposed reputational approach is appropriate given the difficulty of setting robust targets.

Visual amenity impacts of transmission infrastructure:

ETQ46. Do you have views on the retaining the existing scheme to mitigate the visual impact of pre-existing transmission infrastructure in designated areas? Do you agree that any decision to implement new funding arrangements should be subject to updated analysis around willingness to pay?

If the scheme is retained, it is essential the willingness to pay (WTP) analysis is updated. in RIIO-ET1, the amount of funding available was linked to the mean WTP estimates in the 2012 National Grid study[79]. The study refers to survey respondents' concerns about affordability[80]. We would expect that concerns about affordability are as least as much an issue as in the period in which the National Grid study. As such, it should be carefully considered whether mean or median WTP estimates are a sufficiently high threshold on which to linked to amount of funding in RIIO-ET2. It is also important that the amount of funding that might be made available in RIIO-ET2 is considered in the context of other areas of expenditure on transmission infrastructure.

[79] "Consumer Willingness to Pay research"; paragraph 8.
[80] "Consumer Willingness to Pay research"; paragraphs 24-26.

ETQ47. Do you agree with our proposals to modify the implementation process by which funding requests for mitigation projects are submitted and approved?

If high value mitigation projects are to be delivered via the 'baseline' RIIO-ET2 framework, we agree they should be classified as PCDs. This allows TOs to be held accountable for successful delivery. We recommend a reopener is attached to the PCDs so that outputs and allowances can be adjusted if alternative solutions, which are not the result of genuine innovation, are identified.

It should be considered whether high value mitigation projects should be delivered via the competition mechanism. We note the project reducing visual amenity impacts in the Dorset Area of Outstanding Natural Beauty, for which funding was awarded in 2018, satisfies the 'high value' criterion for the 'late' competition model. National Grid will be allowed to recover £116m of expenditure allowances[81]. Using 'early' competition to deliver visual mitigation projects could result in solutions being brought forward that represent better consumer value.

Chapter 5 questions – Maintain a safe and resilient network

ETQ50. For each potential output considered (where relevant):

a. Is it of benefit to consumers, and why?

b. How, and at what level should we set targets? (e.g. should these be relative/absolute).

c. What are your views on the design of the incentive? (e.g. reward/penalty/size of allowance).

d. Where we set out options, what are your views on them and please explain whether there are further options we should consider.

Network Access Policy:

Retaining the licence obligation to publish and comply with the Network Access Policy (NAP) is of benefit to consumers. The NAP sets out the commitment by the TOs to effectively coordinate outage planning and to identify ways in which TO actions can help the ESO minimise constraint costs. We support the intent of the NAP.

The introduction of a single, consolidated NAP for the whole of GB in RIIO-ET2 is sensible given the separation of the ESO and NGET TO as of April 2019 and the potential extension of scope to include third parties. We agree with the NAP being extended to include interactions with DNOs and other third parties – this will support the delivery of whole system outcomes. We recommend the licence obligation on the TOs to publish and comply with the NAP is extended to ensure it updated as needed to capture new processes, interactions, etc. Similar obligations should be placed on the DNOs.

Successful delivery of large capital investment:

The use of PCDs for the delivery of large capital investment is of benefit to consumers. This allows NGET to be held for successful delivery. We support the use of PCDs. We recommend appropriate uncertainty mechanisms are included to allow outputs and allowances to be adjusted if necessary.

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[81] "Determination on National Grid's proposal for reducing visual amenity impacts in the Dorset Area of Outstanding Natural Beauty"; page 1.

ETQ53. Do you agree with our proposed approach to safety?
We agree it is not necessary to include a formal price control output or delivery incentive since NGET's performance against its statutory obligations are monitored and enforced by the HSE.

Network Access Policy (NAP):
ETQ54. Do you agree with our proposal to retain the NAP as a licence obligation?

Retaining the licence obligation to publish and comply with the Network Access Policy (NAP) is of benefit to consumers. The NAP sets out the commitment by the TOs to effectively coordinate outage planning and to identify ways in which TO actions can help the ESO minimise constraint costs. We support the intent of the NAP. We recommend the licence obligation on the TOs to publish and comply with the NAP is extended to ensure it updated as needed to capture new processes, interactions, etc. Similar obligations should be placed on the DNOs.

ETQ55. Do you have any views on the potential risks and benefits of introducing a single, consolidated NAP, and of expanding the NAP to cover interactions with third parties?

The introduction of a single, consolidated NAP for the whole of GB in RIIO-ET2 is sensible given the separation of the ESO and NGET TO as of April 2019 and the potential extension of scope to include third parties. We agree with the NAP being extended to include interactions with DNOs and other third parties – this will support the delivery of whole system outcomes.

Successful delivery of large capital investment projects:
ETQ57. Do you agree with our proposed approach for ensuring TOs do not benefit financially from delays in delivering large capital investment projects?

TOs should not benefit financially from delays in delivering large capital investment projects. Otherwise, there is a risk that a perverse incentive could be created to encourage late delivery, which is not in consumers' interests.

Chapter 7 questions – Uncertainty mechanisms
ETQ68. We would welcome views on the design and suitability of existing uncertainty mechanisms for RIIO-ET2, and whether any of these should be removed.

The proposed cross-sector uncertainty mechanisms are appropriate. In our responses to questions CSQ28-30 and CSQ33-34, we recommend the scope of the Physical Security and Cyber Resilience reopeners is extended to accommodate changes in outputs and allowances that are not driven by changes in government policy.

We agree the ET-specific uncertainty mechanism should be reviewed to determine whether they are still appropriate.

ETQ69. Are there any additional mechanisms that we should consider across the sector and if so, how should these be designed?

The Heat Policy Reopener proposed for the gas distribution price control should be considered for the electricity transmission price control. A significant development of central government policy in this area may necessitate changes to NGET's outputs and allowances.

As recognised in the consultation, future government decisions relating to electric vehicles could have a material impact on transmission network investment needed during ET2. It is prudent to include a mechanism to accommodate this uncertainty.

ETQ70. We would welcome views from respondents on the continuing relevance of these mechanisms and any changes to the way that they operate if they are to continue.

We agree it is necessary to allow outputs and allowances to 'flex' in response to the outcomes of the Electricity Network Access project and the Transmission Charging Review, the development of competition in transmission and whole systems delivery.