RIIO-2 Framework Consultation

Our response

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2 May 2018

By email only to RIIO2@ofgem.gov.uk

Dear Jonathan

RIIO-2 Framework Consultation

Thank you for the opportunity to comment on the above consultation. We are pleased to see that the consultation and accompanying documents build upon the RIIO-2 Open Letter that was published in July 2017, and the subsequent workshops. Our response should be treated as consolidated on behalf of UK Power Networks' three distribution licence holding companies: Eastern Power Networks plc, London Power Networks plc, and South Eastern Power Networks plc.

Our industry is on the cusp of fundamental change with the rapid uptake of electric vehicles (EVs), increased distributed and renewable generation, as well as the emergence of disruptive technologies. Electricity Distribution Networks (DNOs) are at the heart of enabling this low carbon transition. Therefore, it is critical that the evolution of the RIIO framework creates the right environment that encourages appropriate investment in the networks and promotes continued innovation in reliability, resilience and service improvement for the benefit of all customers.

The evolution of the RIIO framework should also ensure that any issues in the current RIIO-1 settlement, whether 'perceived' or 'real', are fully addressed. In Table 1 below, we have summarised our understanding of some of the perceived issues with RIIO-1 and offer up solutions for how these could be addressed within an overall RIIO-2 package:

Perceived issues	Potential solutions
Generous cost allowances	• Greater use of volume drivers and uncertainty mechanisms to further improve the RIIO framework's ability to respond to a fast changing energy sector • Tiered sharing factor allows greater customer benefit for increased network efficiency
Incentives targets are too easy	• Annual updating of incentive targets based on benchmarking of revealed performance

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Perceived issues	Potential solutions
Cost of capital is too high	• Efficient historic debt should receive a fixed allowance to service this and all new debt for the period should be indexed • We disagree with the range for the cost of equity calculated by CEPA, we have noted issues e.g. the risk premium attached to equity needs to be higher than that of debt
Forecasting errors	• Shortening of the price control period to five years given the greater levels of uncertainty • Use of indexation where appropriate to mitigate forecasting errors • Greater use of volume drivers and uncertainty mechanisms to further improve the RIIO framework's ability to respond to a fast changing energy sector
IQI/Fast-track perceived to be too generous	• A smaller reward than in RIIO-1, calibrated upfront and based on RIIO-1 performance as well as the quality of RIIO-2 plans • Simpler mechanism than IQI, provided it is set out clearly in strategy decision documents
Whole system solutions not fully addressed	• A standalone totex pot that recognises where more than one NWO (Network Operator) can propose a solution to an identified network issue to ensure the delivery of the best cost solution • Working groups or similar, such as the ETO User Groups, will provide an opportunity for all parties to identify these activities that could be included within this pot.
Asymmetry of information	• Greater use of volume drivers and uncertainty mechanisms to further improve the RIIO framework's ability to respond to a fast changing energy sector • Annual updating of incentive targets based on benchmarking of revealed performance

Table 1 – Perceived issues with RIIO-1 and possible solutions

Taking these shortcomings and solutions, we have expanded upon these against Ofgem's key topics below and with detailed answers in Appendix 1.

Giving consumers a strong voice

We welcome the introduction of Customer Engagement Groups (CEGs). The non-prescriptive nature of their operation aligns well with our view that network operators are best placed to decide the most appropriate way to engage stakeholders when developing and shaping business plans. We strongly advocated this in our response to Ofgem's RIIO-2 Open Letter and believe it is important for RIIO-2 that the wants and needs of local customers of that network operator are captured in company business plans. Whilst it appears this is the key objective for CEGs, we would welcome clarity on the degree of emphasis Ofgem will expect to place on stakeholders' views when assessing business plans. If Ofgem or subsequent Open Hearings unpick and ignore views formalised through the CEG process, it will undermine all the engagement, time and effort that has gone before.

We believe it is important that business plans reflect stakeholder input and the assessment of the plans should take into consideration those views when Ofgem applies its benchmarking, incentive targets and incentive rates. That is, the RIIO-2 framework should clearly distinguish and allow recognition and reward for those companies that best capture, and subsequently reflect, those views in their business plans.

Responding to changes in how networks are used
To best address this key Ofgem topic, we believe the framework needs to be capable of responding to:

- Changing circumstances;
- Improved network operators' performance; and
- New requirements.

Taking each in turn, the price control framework must be able to take account of the fast paced and radical changes being witnessed within the energy sector, particularly within electricity distribution. It needs to be flexible and able to respond in such a way that companies and customers are not unduly penalised or receive a subpar service respectively. A shorter, five-year price control helps to reduce the risk of forecasting errors and is one of the reasons we are advocates to this move, but going further, we recommend the adoption of indexing where possible and practical so that the price control remains responsive to external changes.

Indexation of elements such as RPEs and cost of new debt ensures protection for network operators and customers, and also ties in with Ofgem's objective of ensuring fair returns within the price control. One area where we feel indexation is not appropriate is in setting cost allowances. Cost allowances set over a price control period provide the incentive for companies to find efficiencies, innovate and ultimately provide better service at lower cost. Ratcheting costs too soon will not only remove the opportunity for companies and customers to benefit from the savings, but also significantly dilute the incentive to seek efficiencies.

The appropriate time to 'reset' allowances is at the start of a price control and we believe a clear element of the RIIO-2 framework should be that companies are rewarded for revealing true costs over the previous period, i.e. RIIO-1. That is, the network operators that are at the frontier of cost efficiency in the previous settlement should receive a reward for helping to lower those benchmarked costs for the following period.

Another area where the price control can be improved to reflect changes is through the annual updating of targets through benchmarking revealed performance. Targets should be sufficiently challenging to continually drive performance throughout the period, and using benchmarked revealed performance to do so ensures simple and transparent rules for network operators and customers to understand. It also rewards true high performance whilst driving continuous improvement. Further work will be required and we will be testing with our stakeholders their appetite for targets that may relax as well as tighten during the period.

In an uncertain future, to accurately predict the uptake of EVs, heat pumps, distributed generation etc. is challenging – but the RIIO-2 framework needs to protect customers from unnecessary costs if these types of activities do not materialise at the scale and timing envisaged at the time of the settlement. For this reason we believe the price control should make greater use of volume drivers and uncertainty mechanisms which may operate to return money to customers in period, further enhancing protection for customers from outturns being significantly different to forecasts.

Whilst the Ofgem consultation makes reference to the importance of addressing whole system activity, we have proposed mechanisms to further realise the benefits across sectors. For example, when developing the energy system, all parties capable of delivering a solution should be identified upfront and be equally incentivised to propose a solution. This is an area which warrants further development to ensure the opportunity of whole system solutions can be realised, and we look forward to working with all parties. Furthermore, there are other key areas in which further benefit can be achieved, such as new incentive arrangements for the delivery of key strategic national priorities (e.g. energy efficiency), enabling low carbon distributed generation to connect and ensuring networks are utilised efficiently.

We believe the points highlighted above are key to how the RIIO-2 framework should look and operate. They go a long way in addressing many of Ofgem's key topics, whilst protecting customers and ensuring that companies are fairly rewarded for truly frontier performance.

Driving innovation and efficiency
Innovation has been a key success within RIIO-1, and is rapidly becoming a business-as-usual (BAU) activity within many companies. As such, we agree with Ofgem's view that innovation funding should be removed for those projects where the benefit is clearly visible and payback is over a shorter horizon. Instead, funding should be retained and expanded for those larger, harder to define projects, particular those pertinent to the energy transition. The increased collaboration with third parties within innovation and indeed wider network needs is a principle we support, but there are a number of factors that need to be considered to ensure it is in customers' interests:

- We welcome the benefits of opening up innovation funding to third party access. We believe that a mechanism, akin to the incentives on connections or stakeholder engagement, would further encourage and instil this culture. We would welcome the opportunity to work with Ofgem to develop this further;
- The current totex model is held in high international regard and incentivises companies to find the best cost solution – if said solution is available in the market there is no reason why a well-run network operator would not opt for this solution, as demonstrated by our flexibility tenders; and
- We welcome competition but only where there is a clear need or benefit for its introduction. Investment decisions must always be in the best interests of customers.

Simplifying the price controls
We have already touched on methods above with regard to the in-period resetting of targets based on benchmarking of revealed performance and the importance of not adjusting cost allowances within the period to ensure simple, justifiable and fair price controls. There are, however, further areas in which this can be improved. We agree with Ofgem's view that there is benefit in incentivising companies to produce high quality business plans, but that the benefit provided by fast-tracking should be reassessed. We do not believe early settlement is necessary, but that the quality of a business plan should be rewarded, most likely through a distinguishable sharing factor, ex-ante reward or a combination of both. As mentioned earlier, the views from the CEGs should also form part of this assessment on business plan quality. That is, the incentive and reward on business plan quality is undertaken on both a quantitative and qualitative level, with the rules around how this will be achieved being clear and transparent to all parties upfront.

Fair returns and financeability
We believe that the overarching principle for setting the cost of capital should be that it remunerates both efficiently incurred past investment and be of a level to attract investment into the sector, based on the risks faced. We are concerned that Ofgem's current proposals and associated methodology will result in the cost of capital being set below a fair level. This risks setting an investor perception that incremental capex destroys value and hence disincentivises investment. This would not be in customers' interests, particularly as significant investment may be required in RIIO-2 to continue to enable the low carbon transition.

For financeability topics such as the cost of debt, we agree that customers should pay no more than the cost to raise efficient debt and that companies should be incentivised to obtain the lowest cost financing without incurring risk. We believe that if a company is assessed as having efficient historic debt then it should receive a fixed allowance to service this and all new debt for the period should be indexed. This would act as a simple, transparent and upfront approach to the cost of debt.

We believe that the cost of equity needs to reflect the level of risk network operators face and it should be derived using sound and well-evidenced economic theory. Whilst we acknowledge the use of the CAPM model along with historical long-run data when calculating the Total Market Return (TMR), there are significant abnormalities that have been applied by CEPA in their approach to setting the indicative range for the cost of equity. We have supplied more detail when addressing the relevant questions in the appendix but in short, we have concerns in that CEPA have apportioned a higher premium to debt risk than that given to equity risk – which goes against logic and casts significant doubt on the estimates provided by CEPA. Furthermore, there are abnormalities in their approach to setting the TMR, the derivation of the asset beta and various other elements in indicating their view. We would welcome working with Ofgem to analyse and work through these issues.

Good performing companies (those delivering outputs at the lowest cost whilst delivering great customer service) should be appropriately rewarded. On the other hand, poor performing companies (those overspending cost allowances whilst delivering poor customer service) should be penalised. This is the basis of RIIO-1 and with our proposals outlined above we are confident this would build on its successes, whilst facilitating an environment for a clearer range in company performance and ensuring fair returns.

These proposals for RIIO-2 must have their rules clearly set out upfront. The use of ex-post failsafe mechanisms such as anchoring, fixed or zero-sum incentive pots would have a counter-productive effect on company drivers to innovate, find efficiencies, reduce costs and would ultimately result in customers receiving a poorer standard of service. Utility regulation should enable an environment for which investors can anticipate the context for future decisions and to make long-term investments with confidence[1].

With that in mind, we believe that by following the above proposals we can ensure a price control that protects customers and delivers frontier performance at the lowest cost, whilst enabling companies to be financeable and appropriately rewarded. This will ensure the RIIO framework remains internationally recognised as being at the forefront of utility regulation and responsive to future energy challenges.

We hope that you will find our comments helpful and if you wish to discuss any part of our response, please do not hesitate to contact us. We look forward to working with you over the coming months to develop the suggestions in this response, and to set up a clear process for RIIO-2 and subsequently RIIO-ED2.

Yours sincerely

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[1] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/31623/11-795-principles-for-economic-regulation.pdf

Appendix 1

Please find our detailed responses to the questions outlined in the Consultation below.

1. **How can we enhance these models and strengthen the role of stakeholders in providing input and challenge to company plans?**

    - **What are your views on the proposal to have Open Hearings on areas of contention that have been identified by the groups?**

We welcome Ofgem's proposals to enhance stakeholder engagement through the establishment of independently chaired Customer Engagement Groups (CEGs). We agree that this new approach will provide greater uniformity across DNOs and enable Ofgem and its challenge group to better assess the quality of stakeholder engagement that informs their business plans. The use of CEGs should also provide increased assurance not only to Ofgem, but also to the DNO, that business plans reflect the expectations and needs of its customers and local communities. As per our response to the RIIO-2 Open Letter, we advocate strong company ownership of business plans and stakeholder engagement and have demonstrated this through activities such as our willingness to pay research[2].

The proposal for Open Hearings is interesting and worth more detailed consideration, with our initial thoughts on the benefits and shortcomings provided below:

Benefits

- Increases the transparency of business plan development
- Allows greater scrutiny and discussion on contentious areas
- Potential forum to highlight best practice in areas of commonality

Shortcomings

- Danger that RIIO-2 Challenge Group and/or Open Hearings could unpick/re-cover ground that has already been debated within the CEGs or other stakeholder discussions
- It is unclear on the positions of each of these groups in the overall hierarchy (does one group's opinion hold more weight than others?)
- Risk that over-representation of invited stakeholders could result in bias of opinions, and again disregard the results from the CEGs and other stakeholder discussions
- Unclear as to how invited stakeholders can be judged to be 'experts' above those already consulted during CEGs or otherwise during business plan development[3]

We recognise that the detail provided by Ofgem thus far is limited and would welcome more detail and examples of how this approach in other sectors has benefitted customers.

[2] http://library.ukpowernetworks.co.uk/library/en/RIIO/Stakeholder_Engagement_Supporting_Documents/

[3] https://www.ofgem.gov.uk/system/files/docs/2018/03/ofgem_consumer_first_panel_year_9_wave_2_consumer_involvement_in_the_price_control_process.pdf

2. **Do you agree with our preferred position to set the price control for a five-year period, but with the flexibility to set some allowances over a longer period, if companies can present a compelling justification, such as on innovation or efficiency grounds?**

   - **What type of cost categories should be set over a longer period?**
   - **How could we mitigate the potential disruption this might cause to the rest of the framework? See below.**
   - **What additional measures might be required to support longer-term thinking among network companies? Do you instead support the option of retaining eight-year price controls with a more extensive Mid-Period Review (MPR)?**
   - **What impact might the alternative option of an eight-year price control with a more extensive MPR have on how network companies plan and operate their businesses?**

As stated in our RIIO-2 Open Letter response, we remain strong advocates of a return to five-year price controls. We believe the increased uncertainty that industry is facing at this time warrants a shorter price control. Such an arrangement presents a better opportunity to set ex-ante allowances alongside appropriate uncertainty mechanisms with improved information for all participants and hence reduce the scope for forecasting errors. We recognise that there are some disadvantages of a shorter price control period, which include:

- Potentially reducing the scope to innovate and deliver greater benefits to customers;
- Potentially reducing the strength on incentives, as investments will pay back over a shorter time frame, resulting in smaller performance improvements; and
- Potential additional costs, as running price controls more frequently will increase the administrative costs that Ofgem sought to reduce when it moved to an eight-year control.

However, in a rapidly evolving landscape, affording stakeholders more regular opportunity to express what they want and how much they value it, aligns well with delivering a price control that delivers the best outcome for customers.

We struggle to see how the practicalities would work for elements of a price control set for a longer period, away from the core set in five years. Allowing certain allowances to run over a longer period would go against Ofgem's desire to construct a simpler price control. Whilst solutions could be adopted to make this achievable, there are many perverse outcomes that could materialise and the administrative load on Ofgem would undoubtedly increase.

It may be attractive to have longer price controls – for HVPs, for example. However, the number of individual discrete HVPs in Great Britain, compounded with different price controls, will unnecessarily complicate the price control even more and increase the burden on Ofgem.

Given the potential for an increased risk of forecasting errors due to the fast-changing nature of our sector, we, like Ofgem, do not believe that continuing with an eight-year price control is the most effective way to combat these concerns. Furthermore, an alternative option of an eight-year price control with a more extensive MPR, as suggested by Ofgem would effectively generate two sub-optimal four-year price controls. An MPR would never allow the same amount of 'resetting' that would be possible during a full price control as the tools available to Ofgem are not as extensive as those available when defining the start of a new price control. It also creates additional resource burden, further complication and increased possibility of challenge from various parties. This is not an option that we support.

3. In what ways can the price control framework be an effective enabler or barrier to the delivery of whole system outcomes?

- **If there are barriers, how do you think these can be removed?**
- **What elements of the price control should we prioritise to enable whole system outcomes?**

We welcome Ofgem's declared policy objective to ensure that the energy system's needs are looked at as part of the whole system, rather than solely from a transmission or distribution system perspective[4]. We believe price controls can play a pivotal part in enabling whole system outcomes but they must provide certainty, transparency and clarity of accountabilities. Getting this right should ensure the lowest overall cost to the consumer can be achieved, and we have already started to identify types of works that could fall into this category, as shown below:

- Balancing services;
- Reactive power;
- Reinforcement;
- Distributed Energy Resources;
- Procurement and dispatch coordination;
- Voltage control;
- Demand Side Response; and
- Connections.

However, rather than try to highlight all the areas where a whole system solution could be applied, Ofgem should focus on those areas of greatest benefit to customers. For these 'focused' areas, the whole system mechanism needs to ensure all players that can contribute to the outcome, can, and that ultimately, the outcome produces the best cost solution for customers.

<u>Enabler</u>

To achieve this, Ofgem needs to take steps prior to the initiation of the respective RIIO-2 price controls, i.e. in 2021 for RIIO-T2 and 2023 for RIIO-ED2. These steps include:

(a) **Identifying the interactions between licensees across network areas and across the whole system.** (This could potentially include interactions across vectors, i.e. between the gas and electricity systems.)

For example, reactive power needs can be addressed in three ways: through investing in assets at the transmission level; through the Electricity Transmission System Operator contracting with generators; or through DSOs developing and operating reactive power markets in the distribution network. One such tangible example is UK Power Networks' joint project with National Grid Electricity Transmission System Operator, known as Power Potential.

Hence, Ofgem needs to understand what individual network licensees can deliver for their own network and for the whole system.

Figure 1 illustrates the separation of activities that are solely delivered by any of the operators in the energy sector:

- Electricity Transmission Operator (ETO);
- Distribution Network Operator (DNO);
- Gas Distribution Network (GDN);
- Gas Transmission (System) Operator (GT(S)O); and

[4] Ofgem's consultation on Future arrangements for the electricity system operator: its role and structure – January 2017
https://www.ofgem.gov.uk/system/files/docs/2017/01/future_arrangements_for_the_electricity_system_operator.pdf

- Electricity Transmission System Operator (ETSO).

Those activities that could be delivered by more than one party are also identified and separated into a standalone 'whole system pot'. Working groups or similar, such as the ETO User Groups will provide an opportunity for all parties to identify these activities that could be included within this pot.

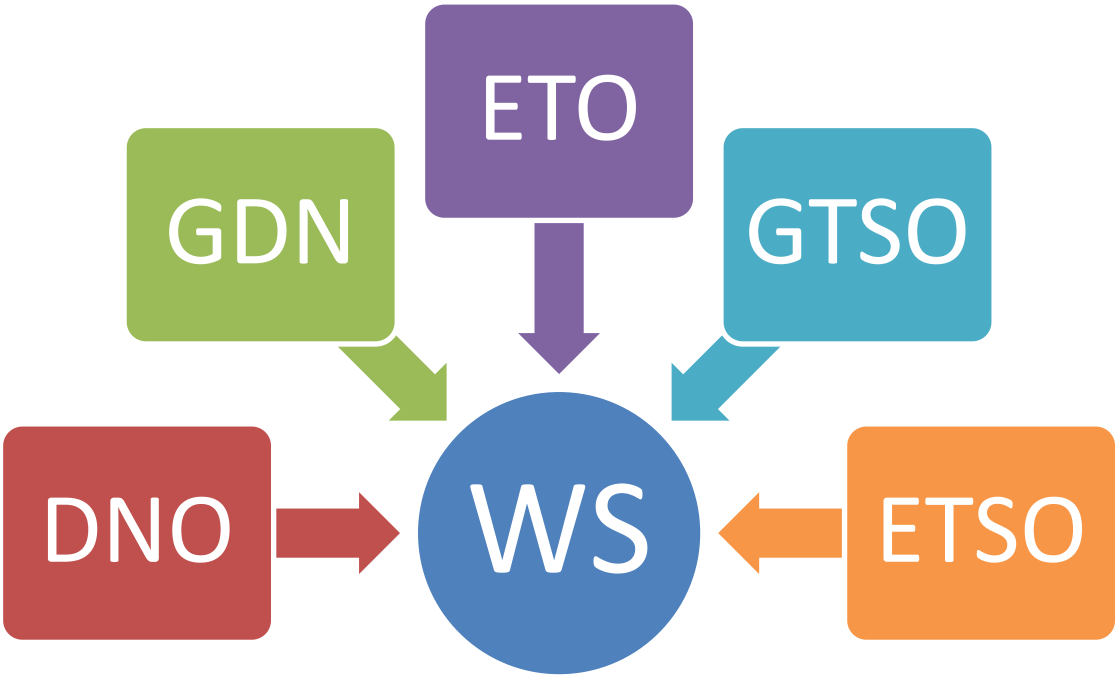

Figure 1 – Diagram illustrating the whole system pot

(b) Identifying the licensees that have the capabilities and resources to deliver outputs across their network and the whole system.

Network licensees have developed specific capabilities that suit the needs of their customers in terms of assets and users' ways of operation. For example, network operators may deploy a mix of asset intervention and flexibility market solutions to tackle peak demand requirements. This means they have the:

- Capabilities to optimise their network and contribute to the wider system; and
- Need to be able to access the resources within their network in an effective way.

Further to Power Potential, UK Power Networks is already demonstrating the capabilities of a DSO via its ANM platform and flexibility tenders. This in combination with (a) above indicates that UK Power Networks will be capable of delivering outputs across both its network and the whole system in RIIO-2.

(c) Clearly assign roles and responsibilities to the licensees with respect to the outputs for their network areas and for the whole system.

Currently, DNOs are acting within their roles and responsibilities. However, DER can have contractual arrangements with third parties other than the DNOs, i.e. with the ETSO. This results in the ETSO utilising resources within a DNO's license area with limited coordination with the DNO, this can potentially produce inefficient outcomes. For example, instructions from the ETSO through the capacity market may not be conducive to the distribution system if it is facing thermal constraints, i.e. instructions outside of the DNO's control could compromise the distribution network's security of supply.

It is therefore imperative that Ofgem ensures that network operators have priority over other operators in their respective network in managing assets and other resources available to them as, ultimately, it is the network operator who is responsible for keeping the lights on.

(d) Structure price controls, e.g. ET2 and ED2, to accommodate different licensees delivering whole system outcomes.

In order to clearly demarcate whole system responsibilities, it is necessary to separate and identify such works that could be delivered by both distribution and transmission, but proves better value for the customer if one is able to do it over the other more cost efficiently. This separated pot must have uniform incentive conditions, i.e. sharing factor, so that any party delivering work in this pot is not favoured over the other due to non-consistent incentive arrangements. The arrangements must also ensure outcomes such that a passive operator, i.e. not delivering the deliverable, does not receive an incentive.

Figure 2 below demonstrates how licensees could behave when presented with a portfolio of incentives for both their network and the whole system. Each licensee will deliver across a frontier (the dashed line below). If the strength of incentives is weighted towards whole system, the licensee will focus its performance towards the outputs in Box A. On the other hand, if the incentives around the licensee's individual system carry more weight, the licensee will focus its performance to deliver the outputs in Box D. Hence, RIIO-2 needs to be clear in how it incentivises whole system outputs without compromising on the delivery of outputs related to licensees' individual networks. This will ensure that licensees progress towards an optimised delivery (Box B).

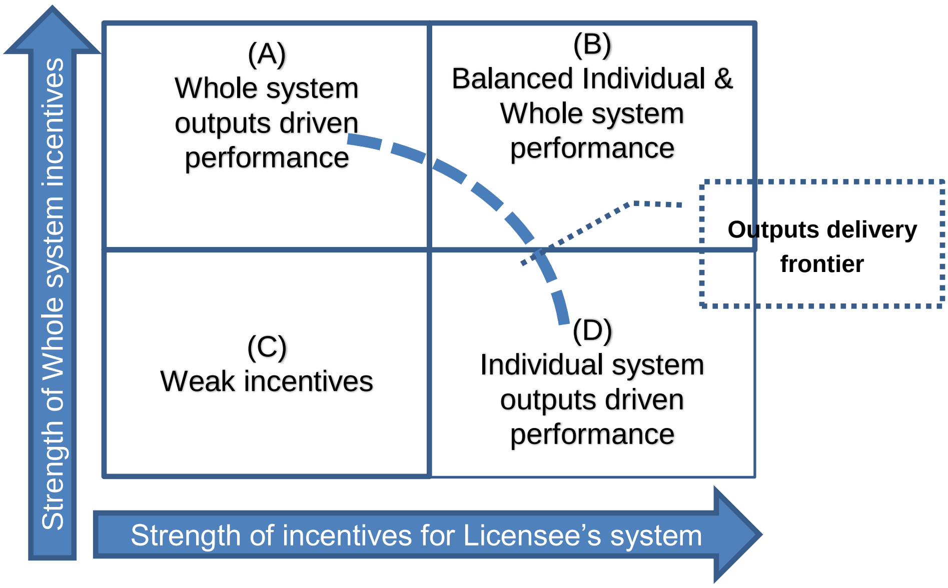

Figure 2 – Representation of how licensees respond to portfolio of incentives

Effectively, RIIO-2 needs to allow licensees to optimise their delivery across the delivery frontier as presented above and balance their outputs across the two axes.

<u>Barrier</u>

The proposed separation of the GD/T and ED starting points of the RIIO-2 price controls will require upfront work across all licensees to ensure that whole system incentives are efficiently calibrated. This should not present an insurmountable obstacle providing all parties recognise the need to work together and it does not become the preserve of those parties whose price controls occur first. For example, the transmission sector would have two years to consider, evaluate cost and plan for whole system projects, whereas the electricity distribution sector would consider similar activities two years behind. This could present a risk that the electricity distribution sector will be disadvantaged over other sectors providing whole system solutions.

The proposed transmission User Groups will, to some extent, mitigate some of this risk by allowing DNOs to provide challenge to schemes that could be delivered by a different sector, however this effectiveness is limited by the realistic level of engagements and early sight of works that could be considered for whole system contestable works. This is further compounded by the natural aversion of the TO to identify parts of its totex allowance that could be delivered at a lower cost via a separate whole system pot, i.e. the TO would forgo the sharing factor sum that it would have got if the project was included in its allowance rather than a DNO delivering it for less, and effectively removing the TO from the work.

Furthermore, the lack of alignment of incentives, sharing factors, cost of equity etc., could lead to the wrong outcomes being delivered due to different signals in different price controls, see Figure 2 above. This can be further distorted with the application of perverse fair return mechanisms such as anchoring. In this situation, a whole system solution could be chosen ex-ante to be delivered most cost-effectively through the ED sector; however, subsequent re-evaluation of sectoral performance results in retrospective application of the anchoring mechanism, causing the ED whole system solution to be worth less to ED licensees. It is important that mechanisms based on relative performance are not operated within price controls, as the predictability of how they will be operated in the period cannot be managed and will result in decisions made at the start of a price control potentially being undone later in the period.

For example, the electricity transmission and distribution sectors both start the year with the whole system unit of output being worth £1. At the end of year one, sectoral performance in ED results in an anchoring adjustment of 0.5 being applied, whereas in transmission the adjustment is 2. The whole system incentive strengths are now £0.5 per unit of output in ED and £2 per unit of output in T.

Summary

RIIO-2 provides the opportunity to include a whole system perspective within the RIIO price control framework. However, in order for this to be successful, Ofgem needs to ensure that it:

- Assigns clear roles and responsibilities to network licensees in the energy system;
- Enables actors to develop and utilise the resources on an equitable basis;
- Aligns outputs and incentives with operators' roles, responsibilities and resources;
- Ensures that incentives and rewards are proportionate to the individual licensees' role in delivering jointly whole system benefits;
- Structures the incentives in a coherent manner enabling licensees to identify a balanced approach in delivering outputs for both their networks and the whole system; and
- Develops a monitoring framework that allows it to verify the performance of licensees, especially where they share the responsibility for whole system outputs with other licensees.

4. Do you agree with our minded-to position to retain the current start dates for the electricity transmission and electricity distribution price controls, and not align them?

As per our RIIO-2 Open Letter response, we believe that extending the RIIO-T1 price control period to align with the start of RIIO-ED2 would make it easier to deliver benefits for customers through supporting the development, assessment and funding of lower cost, whole system solutions. However, we understand and note Ofgem's position to retain the current start dates for electricity transmission and distribution, and as such we agree with the minded-to position. It is imperative that items pertaining to whole system outcomes are developed upfront so that the gap of two years between RIIO-T2 and RIIO-ED2 does not present a barrier to providing the most cost-effective solutions – please see our response to question three.

5. In defining the term 'whole system', what should we focus on for the RIIO-2 period, and what other areas should we consider in the longer-term?

- **Are there any implementation limits to this definition?**

Please see our response for question three. However, in the longer term, for RIIO-3, more focus will need to be given to the decarbonisation of heat and solutions across all vectors, not just between electricity transmission and distribution.

6. Do you agree with our view that National Grid's electricity SO price control should be separated from its TO price control?

Yes, given the direction of legal separation of the ETSO, the next logical step is a separate price control for it. It is important that ETSO solutions that can be attributed to whole system outcomes which are aligned with those equivalent solutions within the transmission and distribution sectors i.e. so no one sector is favoured over the other to ensure the best cost for customers.

However, there are clear distinctions between why an SO needs to be separated from National Grid and why a DSO should be integrated within a DNO, i.e. the DNO to DSO transition. For example, the distribution network is far more interconnected and interdependent, requiring an intimate knowledge of the operation and characteristics of the local distribution network, existing supporting infrastructure and resources. There are ongoing projects and work to facilitate the journey to realising this transition[5].

7. Do you agree that we should be considering alternative remuneration models for the electricity SO?

- **If so, do you have any proposals for the types of models we should be considering?**

Yes – the ETSO is asset light, and its operations will be predominately services based. There are papers that explore different remuneration models for a DSO that views the totex model as superior in avoiding capex bias, which may have some read across when developing ETSO specific models[6]. Any model must take into account services that will be provided by the DSO as to avoid overlap or duplication, and thus not hinder the development of DSOs. That is, such a model should enable DSOs to develop and utilise the resources on an equitable basis. Please see our responses to questions three and six for further detail.

8. Should we consider alternative remuneration models for the gas SO? If so, why and what models?

No comment.

9. What options, within the price control, should be considered further to help protect consumers against having to pay for costly assets that may not be needed in the future due to changing demand or technology, while ensuring companies meet the reasonable demands for network capacity in a changing energy system?

We understand the benefits of avoiding unnecessary capex that would be costly to customers and utilising alternative solutions that would meet the demands in a changing energy system.

We are aware that this idea is not unique to the GB energy system and is being actively discussed internationally. In March 2018 the Grattan report was published, discussing the stranding and under-

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[5] http://futuresmart.ukpowernetworks.co.uk/

[6] Utility Earnings in a Service-oriented World - Optimizing Incentives for Capital and Service-Based Solutions, Advanced Energy Economy Institute, January 2018.

utilisation of assets in the Australian electricity network ultimately resulting in customers' electricity bills being $100 to $400 higher than they should be[7].

In contrast, GB DNOs have a good track record on this front to build upon, including recent developments under RIIO e.g. incentives, totex and sharing factors which have driven the best cost solution regardless of capital or operational expenditure. In addition, we believe there are additional mechanisms that could improve the framework further:

- **Generation Index:** A key role of a DSO will be to maximise the use of existing network assets in order to defer and/or avoid investment to save money for customers. A good measure of how well we achieve this is the utilisation of our assets. We already have Load Indices (LI) in place, but there is currently no metric to capture how we utilise our assets for generation. As the UK economy continues its transition, moving away from traditional fossil fuel power generation and towards renewable generation, we think there is merit in developing a reporting framework around the utilisation of the network by generators at both the primary and the secondary level[8]. This will help identify where DNOs are using smart solutions, such as flexibility, to maximise utilisation of network assets and facilitating the connection of generation, and where companies are simply investing in new assets. Taking this concept further, the level of utilisation of assets could be used as a trigger or evidence to support DUoS funded reinforcement where this could reduce the constraints which DER are subject to. Therefore, there must be an overall measure of asset utilisation. This idea will need further development – in particular, how it would interact with the current LIs.

- **Distribution (secondary) Load Indices:** Utilisation of assets at the distribution (secondary) level could be monitored with smart meter data. Currently in RIIO-ED1, we have the LI at a primary level, but the current limited visibility of load at the secondary level has meant a restricted indication of how our network is utilised. Smart meter data could resolve this and further maximise network utilisation as well as providing early warning signals of where intervention is required. We recognise the importance and need for appropriate handling of consumer data, security and privacy controls and in addition to being GDPR compliant we are developing a Data Privacy Plan which will underpin our approach to the collection and utilisation of consumption data. Our approach in this matter will be informed and tested with our stakeholders before implementation.

- **Distribution Generation Curtailment Index:** There may be merit in the development of an incentive based around the amount of DG curtailment. For example, through our Flexible Distributed Generation (FDG) connection offering we allow DG resources to connect in areas of network constraint without the need for reinforcement, by providing a flexible connection. An incentive could be placed upon these types of arrangements to ensure this level of curtailment is not excessive, encouraging and developing a strong DG market.

In addition to the above, we should recognise existing mechanics that align the interest of customers and companies:

- **Retaining strong sharing factors and efficiency**: Network operators should be incentivised to maximise asset utilisation and efficiency such that operators are not perversely encouraged to invest and grow the RAV. It is also worth noting that fair return mechanisms such as the proposed anchoring option would dilute incentives. In the first two years of RIIO-ED1, we have returned over £150 million of funding to customers and are expected to make further returns over the course of the period through the operation of the annual updating of expenditure[9,10].

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[7] https://grattan.edu.au/wp-content/uploads/2018/03/903-Down-to-the-wire.pdf

[8] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/695797/Electricity.pdf

[9] http://library.ukpowernetworks.co.uk/library/en/RIIO/RIIO-ED1-Commitment-Report/UK+Power+Networks+RIIO-ED1+Business+Plan+Commitment+Report+2015-16.pdf

[10] https://www.ukpowernetworks.co.uk/internet/en/about-us/documents/6955%20ED1%20report%202017%2010%20INT%20final.pdf?track=ED-final

- **A framework that does not penalise traditional capex solutions**: As the first DNO to carry out flexibility tendering and Active Network Management (ANM), we have pioneered approaches that have avoided unnecessary capex spend[11]. The Flexible Plug-and-Play (FPP) project saved DG customers in our area £36 million on their connection offers in the trial area (a 700km² area of the distribution network between March and Peterborough in the East of England)[12]. The project has been fully adopted into BAU and continues under the name of Flexible Distribution Generation (FDG)[13]. However, a cost is still associated with flexible solutions and the framework must ensure the right economic decision can be made. For example, where a CBA points to a capex solution as better value than paying money for an alternative, the framework should not discredit the capex solution option.

- **Uncertainty and Volume Driver mechanisms**: In RIIO-ED1 there are mechanisms which protect customers from unnecessary costs[14]. For example, we have the load related expenditure reopener (LRR) whereby if demand does not materialise and DNOs do not spend beyond a threshold, 100% of the money is returned to the customer. These mechanisms are available in RIIO-ED1 and include:

    - Street works;
    - HVPs; and
    - Innovation roll-out, etc.

  Relatively simple enhancements to this framework could deliver further benefits. For example, the LRR mechanism could be run mechanistically in a symmetrical way every year. At the end of the price control an in-depth assessment could be undertaken to finalise any adjustments.

10. In light of future challenges such as the decarbonisation of heat, what should be the role of network companies, including SOs, in encouraging a reduction in energy use by consumers in order to reduce future investment in energy networks?

- **What could the potential scale of this impact be?**

One of our core responsibilities as a DNO is to ensure effective and efficient development of the distribution network and we recognise the role that energy efficiency can play in reducing peak demand. We have first-hand experience in this field through one of our innovation projects – **energy**wise (also known as Vulnerable Customers and Energy Efficiency)[15], investigating how DNOs, in collaboration with an energy supplier, charity groups and local community actors, can support residential customers who may be struggling with fuel bills to better manage their household energy usage, and consequently their energy bills, by changing their behaviour.

We believe learning from innovation projects such as **energy**wise can offset some, but not all, network reinforcement. For example, on average participants reduced their average electricity consumption by 3.3% over the energy saving trial, representing a 5.2% reduction in average evening peak demand per household[16]. However, for these savings to continue, the energy efficiency measures need to remain installed/used for a sufficient of period of time to ensure prolonged deferral of investment such that the economic case is justified.

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[11] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Plug-and-Play-(FPP)/

[12] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Plug-and-Play-(FPP)/Project-Documents/Close-Down-Report_Final.pdf

[13] https://www.ukpowernetworks.co.uk/internet/en/our-services/list-of-services/electricity-generation/flexible-distributed-generation/

[14] https://www.ofgem.gov.uk/sites/default/files/docs/2013/02/riioed1decuncertaintymechanisms_0.pdf

[15] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Energywise/

[16] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Energywise/Project-Documents/energywise+Final+Energy+Saving+Trial+report+v1.6+PXM+2017-05-24.pdf

Furthermore, a project by Electricity North West (ENW), called Power Saver Challenge, avoided investment in an urban primary substation, saving customers money and extending the life of the substation by giving customers a reward for reducing the amount of electricity used[17].

However, there are additional barriers to DNOs delivering energy efficiency:

- The lack of DNO experience in delivering such schemes; and
- The inability to monetise the additional benefits that do not accrue to the DNO (e.g. reduced generation costs).

DNOs can continue the learning of **energy**wise and Power Saver Challenge by collaborating with referral networks such as Citizens Advice and other established intermediaries.

Depending on local factors, energy efficiency may have benefits for the wider network or may increase costs to distribution customers without delivering benefits. The inclusion of energy efficiency will need to be considered carefully and all parties will need to understand and be clear on the roles and responsibilities as well as the incentive arrangements.

We welcome Ofgem considering the potential role that network operators, including system operators, could play in encouraging end-use energy efficiency[18]. However, the majority of households in Great Britain use mains gas to heat their properties. Only four million households in Great Britain use non-gas heating fuels, with more than half of these using electricity to heat their properties. Several key energy efficiency measures are targeting the thermal efficiency of properties (e.g. wall and loft insulation and double glazing) or heating systems (e.g. boilers, smart heating controls). With a small number of households on electric heating in Great Britain, these interventions will have a limited impact on the electricity DNOs as they will mainly result in reduced gas consumption. Only marginal electricity network benefits can be realised from these interventions when deployed to gas heated properties that also use secondary electric heating.

Therefore, it is a paramount priority to identify which energy efficiency interventions can benefit electricity distribution customers. Energy efficiency measures such as lighting, electricity smart meters and some smart home products have the potential to reduce the electricity consumption at peak times. However, the uncertainty over the savings realised through these interventions is higher compared to wall/loft insulation and heating systems as it will depend on:

- Customer uptake;
- Behavioural change and retention of the change over time; and
- Synchronisation and aggregation of customer responses and energy savings.

Furthermore, data from smart meters will give NWOs visibility of consumption and identify areas that could benefit from efficiency. On the other hand, smart meter data will inform NWOs where usage will increase from the proliferation of LCTs. There are opportunities to use the incentive framework to facilitate this.

On the decarbonisation of heat, significant societal benefits may be realised from a move away from using gas as the primary heat fuel in homes. Shifting demand onto electricity networks, even with energy efficiency measures in place, will undoubtedly require interventions on the electricity network. Whilst a full array of technologies will be deployed, there is no escaping the reality that in places, network upgrades will be required.

RIIO-2 should clearly set out the requirements licensees are expected to meet, so that business plans are developed accordingly and stakeholders are given ample opportunity to provide their input. Allowing coordinated network upgrades for heat requirements with those of EVs, should help keep cost increases as low as possible as the country transitions in both these key areas.

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[17] https://www.enwl.co.uk/innovation/smaller-projects/other-projects/power-saver-challenge/

[18] https://www.ofgem.gov.uk/system/files/docs/2018/03/riio-2_event_shaping_the_use_of_networks.pdf

We are currently working with a gas distribution network (GDN) operator and BEIS to understand the implications of a migration to electricity for heating.

11. Do you agree with our proposal to retain dedicated innovation funding, limited to innovation projects which might not otherwise be delivered under the core RIIO-2 framework?

We agree, but think the following characteristics should be considered for dedicated innovation funding:

- Funding for higher risk, low technology readiness level (TRL) solutions;
- Increased collaboration between licensees; and
- Opportunities to drive third party access to innovation funding.

However, a question remains in where the line is drawn between what is considered business as usual innovation activity and those larger projects which warrant innovation funding – we welcome the opportunity to work with Ofgem and stakeholders to clearly demarcate these two types of innovation activities.

12. Do you agree with our three broad areas of reform: i) increased alignment of funds to support critical issues associated with the energy transition challenges ii) greater coordination with wider public sector innovation funding and support and iii) increased third party engagement (including potentially exploring direct access to RIIO innovation funding)?

i. Yes – networks have made marked progress to align strategic priorities through the sector specific Innovation Strategies[19]. Whilst we identify with the need to utilise the funding to channel strategic energy initiatives, it is important that the funding available can be applied flexibly, so that the sector can respond appropriately to a fast-changing energy landscape and does not ignore upcoming challenge areas and unintentional loss of associated opportunities.

ii. Yes – however, interdependencies of the funding requirements should be accommodated. Networks currently utilise the Network Innovation Allowance (NIA) to fund the licensee costs, as the network benefits will accrue to customers. Please see our NIA annual reports for more detail and examples[20].

iii. Yes – we understand the benefits of opening the funding up to third party access. UK Power Networks' 2018 Network Innovation Competition (NIC) bid is third party led and this approach is supplying us with first-hand experience of the challenges unregulated third parties face when bidding in a regulated environment. We welcome Ofgem's definition of engagement in this context. A possible solution is to incentivise networks to engage with third parties, i.e. through a mechanism akin to the incentives on connections or stakeholder engagement.

13. What are the key issues we will need to consider in exploring these options for reform at the sector-specific methodology stage, including:

(i) What the critical issues may be in each sector and how we can mitigate the bias towards certain types of innovation through focusing on these issues?
(ii) How we can better coordinate any dedicated RIIO innovation funding with wider public sector funding and support (including Ofgem initiatives such as the Innovation Link and the Regulatory Sandbox)?

[19] Innovation Strategy (ENIS) can be found here: http://www.energynetworks.org/assets/files/electricity/futures/network_innovation/electricity_network_innovation_strategy/Energy%20Networks%20Association%20-%20Electricity%20Network%20Innovation%20Strategy-March%202018.pdf

[20] http://innovation.ukpowernetworks.co.uk/innovation/en/why-we-innovate/#how

(iii) How we can enable increased third-party engagement and what could be the potential additional benefits and challenges of providing direct access to third parties in light of the future sources of transformative and disruptive innovation?

i. As RIIO-ED2 is several years away, the focus should not be on determining innovation areas now based on current issues or second guessing future priorities. Instead the framework should focus on how innovation areas will be determined, reviewed and refreshed throughout RIIO-ED2.

   Critical strategic areas to focus on should align with national strategies such as the government's Clean Growth Strategy, Industrial Strategy and National Infrastructure Commission roadmaps, as well as key strategies from the Mayor of London's office, where applicable to electricity networks. Key issues, as we see them, could be:

   - Improving energy efficiency – energy efficiency is a key area that can reduce the carbon footprint of each customer; as such, the ability for networks to engage and demonstrate future efficiency solutions could prove to be a key area.

   - Facilitating the transition to low carbon transport – by 2030, we currently forecast 1.2–1.9 million EVs on our networks; as such, to ensure networks facilitate this transition, new solutions and products should continue to be trialled in this area.

   - Accelerating clean growth, delivering clean, smart flexible power – the future distribution network will need to be incredibly dynamic and agile to facilitate clean growth; as such, we should focus on developing new solutions and flexibility products to facilitate the low carbon transition. The added benefit to the whole system would be to develop a liquid market for flexibility. Our Flexible Plug and Play (FPP) project is an example of how innovation can facilitate more renewable energy connecting to our existing distribution networks without the need for reinforcement.

ii. Better co-ordination between Innovation Link/Regulatory Sandbox and networks on the above strategic priorities would be beneficial as we currently do not have an opportunity to provide advice or support to any Innovation Link/Regulatory Sandbox submissions that may involve networks. Furthermore, the development of a 'Yellow Pages' of innovation across these sectors could be a practical opportunity to drive consistency and streamline guidance across the sector. Such a tool could include a Frequently Asked Questions section for any initial interactions and provide a roadmap of process.

   Collaborations between various funding sources in the market have been evident in 2017. Examples of rare consortia being formed under the Innovate UK, Vehicle to Grid fund are a true example of this approach working in action. UK Power Networks participated in five of the consortia bids, and upon award is utilising NIA funding to deliver the network learning. Access for networks to this level of collaboration with cross-sector participants is extremely valuable.

   It is important to note that the NIC framework would not be suitable for this type of cross-sector funding due to the speed and onerous nature of the bidding process. We welcome a framework within RIIO-ED2 to ensure network customers continue to benefit from such demonstrators in the future.

iii. To increase engagement of third parties, we suggest continuing to raise awareness at:

   - Energy Innovation Centre (EIC);
   - Power Networks Demonstration Centre;
   - Hackathons;
   - Innovation events on key topics, sustainability and cross-sector; and
   - Problem statement releases and calls for ideas.

There are clear benefits of third party engagement in innovation, with the potential to provide richer ideas and disruptive approaches. However, there are challenges that need to be noted:

- The cost of bidding into the NIC is vast, and the effort required resource intensive, and as a result NWOs could be reluctant to compile several bids with third parties simply to fail. Furthermore, feedback from third parties suggests they require licensee experience to help them with the bidding process;
- Controls to ensure transparency of the use of public funds;
- Efficiency arrangements on how mandatory contributions are managed;
- Consideration needs to be given to how data can be released at the bid stage to allow third parties to develop their benefits case without compromising data security and protection; and
- Earlier validation that the issues being addressed by a third party are indeed priority areas.

14. What form could the innovation funding take?

- **What would be the advantages and disadvantages of various approaches?**

Innovation Funding Form	Advantages	Disadvantages
Roll 0.3% of revenues into the allowance settlement, separately bucketed to ensure networks continue to innovate to reduce costs to customers – potentially with a separate sharing factor	• Gives licensee autonomy on areas to innovate to outperform the business plan • Reduced reporting and regulatory governance costs • Increased pace • Increased incentive to utilise the funding to achieve near term benefits for customers	• Focus could only be on near term benefits and high technology readiness levels • Reduced licensee collaboration and sharing as this solution may drive commercial advantages • Reduced fast follow opportunity for other networks
Rebrand NIC to be a Network Innovation Collaboration fund – with high consortia and collaboration bid entry requirement weighting	• Removes the competition element across licensees • Increased wider industry actors, which could drive faster wide spread deployments • Drives collaboration between sectors and licensees	• Bidders could get the wrong message regarding primary objectives of the fund, and could mistake the main objective of the fund to being collaboration.
Remove IRM as RIIO-ED1 has shown this mechanism to be ineffective	• Licensees are able to make or defend a case, based upon benefits delivered, exceptionality of the innovation delivered, this will ensure licensees are incentivised to share and can be rewarded for such leading behaviour	• Ability to respond to a changeable energy sector may be limited by removal of the IRM – however uptake and award of the IRM has not been successful

15. How can we further encourage the transition of innovation to BAU in the RIIO-2 period? How can we develop our approach to the monitoring and reporting of benefits arising from innovation?

We advocate continued use of strong sharing factors to incentivise companies to innovate, as this will encourage companies to adopt innovation into BAU so that companies will seek cost efficiency through innovation. Allowances should be based on revealed costs in the RIIO-1 period in which innovation has revealed efficiency. Consideration needs to be given to how fair return mechanisms, such as anchoring, would distort and dilute the incentive to innovate – please see our response to question 45.

The existing electricity reporting mechanism (table E6 in the annual RIGs submission) is effective and we have demonstrated how BAU transitions have been a success in RIIO-ED1 – e.g. we have the highest number of deployed solutions and savings to customers. Furthermore, a consortia of electricity and gas networks through the EIC have commissioned a piece of work to inform the future measurement of innovation across all licensees. We would welcome the results of this work being taken into account when developing Ofgem's approach to monitoring and reporting of benefits in RIIO-2.

16. Do you agree with our proposal to extend the role of competition across the sectors (electricity and gas, transmission and distribution)?

- **What are the trade-offs that will need to be considered in designing the most efficient competitions?**

We agree with Ofgem in the desire to extend the role of competition in areas where there is clear evidence that competition will deliver benefits to customers. It is important to factor in the context and sector specific characteristics and ensure that a full, rounded evaluation is undertaken, recognising the energy transition required of parties.

Ofgem will need to balance the investment case with the burdens of:

- Constructing;
- Simplicity; and
- Greater dependency in DSO world, etc.

However, we do not agree with 'forcing' competition, i.e. propping up infant and underdeveloped sectors. A well thought out price control, with strong, appropriate incentives, should always favour providing the best cost solution, as network operators are driven to do so regardless of whether it is an internal or market provided solution (e.g. flexibility tendering).

For distribution networks, one of the benefits of flexible solutions is – as Ofgem indicates – the option value of being able to avoid reinforcement that may not ultimately be required. However, on some occasions this may mean solutions could be more costly in the short term but still be in customers' long term interests. It is important that Ofgem's approach to benchmarking recognises this additional 'option value' and does not penalise companies for pursuing appropriate higher cost solutions. Furthermore, there needs to be recognition that the uncertainty involved in decision making may lead to additional capital investment, such as preparatory work being undertaken, simply to keep an option open.

From our response to question 35, there are distinct differences between OFTOs and DNOs:

- Fixed 20-year revenue stream which is RPI linked;
- No risk of regulatory reset;
- No construction risk; and
- Financing can be largely completed upfront, implying limited refinancing risk.

Furthermore, applying transmission-style competition to distribution companies is not appropriate due to the:

- **<u>Difficulty to identify separate parts of the distribution network for tender</u>**: We consider that at the distribution level it will be even more difficult than for offshore and onshore transmission to identify separate assets which can be subject to a competitive tender process. The distribution network has much greater interconnectivity and interdependency such that we are concerned that if new, high value distribution assets are subject to tendering, this will have an impact on how we run our existing networks and the service we will be able to provide to our customers.

- **<u>Risk that customers do not get the same level of protection</u>**: We are concerned that Independent Distribution Network Operators (IDNOs) and Competitively Appointed Transmission Operators (CATOs) are not subject to the same outputs and incentives as DNOs and TOs.

Consequently, customers on those networks may not receive the same quality of service – particularly around response to faults, engaging with customers and stakeholders to understand their needs and helping to deliver social obligations. These are considerations that IDNOs or CATOs do not need to consider to the same degree when bidding for work and as such it is likely an artificially lower cost can be presented, but one that provides considerable danger of not being to the same standard nor taking account of future requirements of the wider network.

Equally, the regulatory framework is driving us to proactively consider how we play a role in delivering the benefits of a smart, flexible system. The lack of exposure to the price control framework may limit the extent to which IDNOs and CATOs can play a role in delivering lower cost whole system solutions for customers. Growth of these independent networks meshed within an existing DNO present a significant risk of creating inefficient network operation and as the role of the DSO increases, the inability to make use of, or being forced to work around the IDNOs and CATOs networks, will ultimately result in the customer paying more. Therefore, careful consideration needs to be given to increasing the role of competition in these areas, as we do not want it to be at the cost of a poorer, and more expensive service for customers.

17. Do you consider there are any reasons why our new, separable and high value criteria might not be applicable across all four sectors?

- **If so, what alternative criteria might be suitable?**

We have a greater number of smaller value projects in comparison to those seen at the transmission level. As a result, the £100 million high value threshold set by Ofgem would have a limited effect at the distribution level. If this value were to be lowered to capture a greater number of distribution projects, we would also question Ofgem's desire to do this. Any lowering of the threshold and therefore increase in the volume of projects that would be put through this mechanism will add complexity, which is at odds with Ofgem's desire to simplify the price controls.

Furthermore, Section 9 of the Electricity Act 1989[21] places a duty on the electricity distributor:

a) to develop and maintain an efficient, co-ordinated and economical system of electricity distribution; and
b) to facilitate competition in the supply and generation of electricity.

The risk of having multiple operators over a geographic site (i.e. many more IDNOs within a DNO area) will hinder the ability for a DNO to maintain a centralised and strategic view of ensuring its network is operated efficiently. Additionally, issues may arise as IDNOs and non-regulated competitors are not subject to the same stringent regulations applied by the RIIO framework and would possibly run the risk of a poorer, less coordinated service for customers – please see our response to question 16 for more detail.

18. What could the potential models be for early stage competitions (for design or technical solutions)?

- **What are the key challenges in the implementation of such models, and how might we overcome them?**

In electricity distribution, we are using flexibility tenders in our transition to a DSO whilst making effective use of asset utilisation. We identify a problem and go out to the market for technology agnostic solutions. But given the licensee has the obligations, it seems to us that the most holistic solution will be for the DNO/DSO to design and run the tender rather than Ofgem. It would be an insurmountable challenge and incredibly resource intensive for Ofgem to manage flexibility tenders nationwide. Similarly, the current TSO does not have the capabilities to carry out this role, nor should it seek to do so in the future.

[21] https://www.legislation.gov.uk/ukpga/1989/29/section/9

The DSO's responsibilities encompass a far broader spectrum than that of the current TSO – including reliability and customer service. Ensuring a fully co-ordinated and integrated approach at the local level will be best achieved by the local operators themselves. We are aware of advocates for contracting all of the roles and responsibilities but reference our response to the Helm review in this regard:

> *"Whilst we understand the concept of an overarching organisation contracting out all services, and delivering best value for customers – it is a model that is suited to large, high cost infrastructure projects. Where the majority of work is multi-disciplined, high volume and low cost, such as cable fault repairs and low value connections – administrative burden, contractual issues and potential exploitation can all result in greater cost and poorer service to the consumer. The recent Strategic Vision for Rail echoes this view, recognising that "energy and time which could be spent solving the problem can be lost in contractual debate and industry dispute processes."*[22]

Risk of non-delivery is mitigated – but not eliminated – by contract management. It is important to note that only the financial risk can be mitigated, whilst a licence breach and ultimate reputational loss cannot and will have to be subsumed by the network operator.

19. What views do you have on our proposed approach to specifying outputs and setting incentives?

- **When might relative or absolute targets for output delivery incentives be appropriate?**
- **What impact would automatically resetting targets for output delivery incentives during a price control have? Which outputs might best suit this approach?**

We would welcome further detail on the interaction between licence obligations and output delivery incentives. It is our understanding that a licence obligation are effectively a 'minimum standard' that must be met by licensees. Failure to do so would result in a licence breach and penalty. An interpretation of the current definition from the RIIO-2 consultation of output delivery incentives suggests that a reward could be applied to any service beyond that minimum standard and that any service below would result in an incentive penalty and a licence breach simultaneously, as depicted in Figure 3 below.

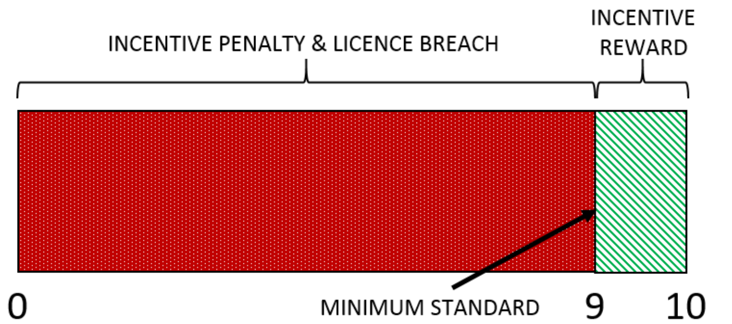

Figure 3 – Interpretation of RIIO-2 interaction of Licence Obligation and Output Delivery Incentive

If this is the correct interpretation, this scenario is a far cry from what the licence conditions are today. With RIIO-2 promising to deliver 'tougher' targets, there is a real risk that licensees could find themselves in a licence breach scenario. A licence breach is a serious label to apply to not hitting a target, and would undoubtedly bring with it severe ramifications, both financial and reputational. If it is Ofgem's intention to set the minimum standard at a deemed 'acceptable' level and not that of a tough, frontier level, then it is more likely that licensees will find themselves in reward territory – a situation Ofgem has set out to guard against. We do not believe Figure 3 is representative of Ofgem's position. Instead, we consider Figure 4 to be the correct interpretation of what was intended, but we welcome clarification on this point. That is, a minimum

[22] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/663124/rail-vision-web.pdf

standard should be set at a level deemed acceptable, and a tougher target set at a higher level of performance with a reward and penalty mechanism symmetrically applied around this target. Any performance difference between the maximum penalty and the defined minimum standard would sit in a dead banded area, as depicted below in Figure 4.

This will guard against unnecessary licence breaches and ensure targets can be set at suitably challenging levels.

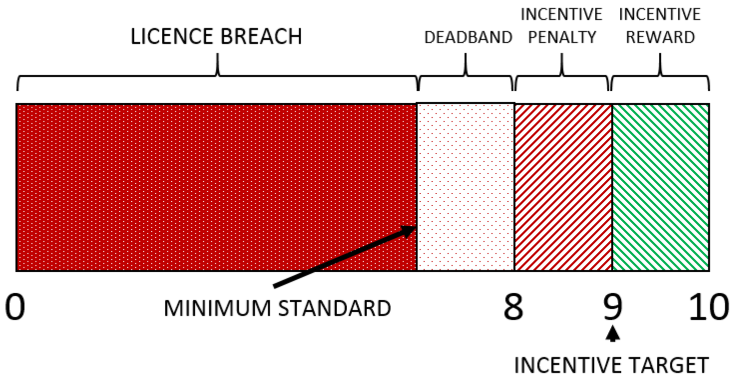

Figure 4 – UK Power Networks' view of RIIO-2 interaction of Licence Obligation and Output Delivery Incentive

We believe that it will be possible to annually update certain incentive targets within period, although we note that may entail additional work for all parties within period. Nevertheless, we think that if the target resetting methodology were set out clearly upfront, then annually updating benchmarks for revealed performance as price controls progress, will minimise scope for perceived errors to arise. One such example that has been cited by various stakeholders is the Interruptions Incentive Scheme, which was the subject of a legal challenge at the start of RIIO-ED1. Ofgem's approach, which was upheld at the CMA, was to set the targets early in the process and include improvement factors. For RIIO-ED2 we believe that to overcome the questions that have been posed against this approach it would be appropriate to apply the target setting methodology consistently over time, but to utilise new data as it becomes available to "fill in" the performance targets for latter years. Figure 5 provides a simplified example of how this could be achieved.

RIIO-ED1							RIIO-ED2				
Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 1	Year 2	Year 3	Year 4	Year 5
2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	48.0	47.0	45.9	44.9			47.8				
		47.0	45.9	44.9	43.7			46.7			
			45.9	44.9	43.7	44.7			46.2		
				44.9	43.7	44.7	46.1			46.2	
					43.7	44.7	46.1	45.9			46.5

Target tightens

Target flat

Target relaxes

Key
48.0 Revealed Performance
47.8 Target

4 year rolling average

2 year lag

Targets have the ability to tighten and relax depending on revealed performance

Figure 5 – Indicative example of target setting for CMLs

In the diagram above the targets for the first two years of RIIO-ED2 would be visible to licensees before the start of the control. In subsequent years, the earliest year of the benchmarking window is dropped and the window is moved a year to the right, thereby bringing in more recent performance. Using the same methodology to update targets as was used to set the initial targets provides clarity and certainty to licensees of the approach, whilst bringing in more recent benchmarked performance addresses Ofgem's and stakeholders concerns of including relative performance and recognising improvements that were not originally envisaged. The incentive to improve remains, each licensee has its own targets and in any one year it can outperform them, but the benchmarking results in tighter targets in future years, which not all licensees would be able to meet, unless they make further performance improvements, which customers would benefit from. Benchmarking revealed performance in this way also negates the need for Ofgem to postulate improvement factors, which may prove to be unduly conservative, or optimistic. In the diagram above we note that performance targets could relax, as well as tighten. We believe this requires further discussion and may ultimately need to be addressed in the detailed sector specific methodologies.

20. What views do you have on our general approach to setting cost allowances?

At this stage the Ofgem cost assessment is very high level, and we look forward to developing this more through the sector specific consultation. However, we have the following comments and suggestions:

- We have noted Ofgem's thoughts of annually reviewing the revealed costs of companies. This will complicate the price control, generate extra work and effectively create annual price controls. Ratcheting allowances in such a way reduces the incentive for companies to deliver frontier performance, as the scope to benefit from cost efficiency is severely curtailed;
- This lack of clarity extends to the role of different forms of cost assessment benchmarking that Ofgem may apply. As part of the RIIO-ED1 slow-track process, Ofgem used three overarching models which ultimately provided a 50:50 split between totex benchmarking and disaggregated models. Ofgem's suggestions of updating elements based on unit cost analysis imply a heavier reliance on disaggregated modelling – this would be a retrograde step. As the energy transition gathers pace, focussing on line item capex type activities rather than the overall picture would be unhelpful;
- On areas of competition, we welcome Ofgem's desire to increase competition but only when it is fully evidenced to be in customers' best interests. Please refer to our response to question 16;
- On the subjects of the IQI, fast-tracking and the business plan, we agree with Ofgem's position that the lack of comparators within the transmission sector makes it inappropriate to have fast-tracking but believe there are strong benefits in retaining similar mechanisms in the distribution sector. Please refer to our response to question 25;
- We note Ofgem's five suggested Return Adjustment Mechanisms (RAMs), but do not believe adjustments based on relative performance are in the best interest of customers. The effect of these would make it difficult for companies to plan business strategies due to unknown factors dependent on others' performance;
- On RPEs, please see our response to question 21; and
- We remain open to Ofgem's suggestion of the greater use of volume and revenue drivers where it can be clearly delineated, as their use in RIIO-1 has been successful at providing protection for customers and licensees. We look forward to participating in their development in the RIIO-2 sector specific phase.

21. What views do you have on our intention to index RPEs?

We support the indexation of RPEs in RIIO-ED1, as highlighted in our RIIO-2 Open Letter response, and we look forward to working with Ofgem to develop this thinking. This was an area in RIIO-1 that required a number of macro-economic and regional forecasts to be made, and experience has shown that errors in these forecasts can lead to companies and customers being exposed to factors largely outside of their control. Indexing should mitigate past experiences and provide improved protection for customers and companies. However, stepping back and taking a high-level view may indicate that if the overall materiality of the issue is relatively small – in our current eight-year control, we received circa £2 million a year – then providing no specific RPE allowances/mechanisms may be inappropriate.

22. What impact would resetting cost allowances based on actual cost performance (eg benchmarked to the average, upper quartile or best performer) during a price control have? Which cost categories might best suit this approach?

We have noted Ofgem's thoughts of annually reviewing the revealed costs of companies. This will complicate the price control, generate extra work and effectively create annual price controls. Ratcheting allowances too soon reduces the incentive for companies to deliver frontier performance, as the scope for capturing cost efficiency is severely curtailed.

There is the further question of what would happen if the upper quartile decreases – i.e. the worst companies get better, but the top companies get worse. That is, any resetting of allowances needs the ability to increase or decrease. Further, there is the possibility that costs will not always decrease in the fast-changing energy landscape we operate in today. For a method like this to be valid, it would place a larger onus on consistency of approaches and scrutiny of reporting to Ofgem. The totex regime under RIIO has been successful in providing companies with more levers to deliver services, resulting in solutions being delivered for lower costs. For example, UK Power Networks' Alliance has resulted in costs being recorded in different categories, due to us changing how we deliver work.

We do not believe any cost categories appear suitable for this type of annual adjustment. We believe the totex regime is better at revealing overall costs than running individual assessments at a disaggregated level within the price control/annually. Such a method would undermine the benefits of the totex system and potentially devalue approaches on flexibility, i.e. if such approaches yield higher unit costs in the short term, whilst providing option value over the medium to long term. Furthermore, relying solely on disaggregated assessments could be distorted by different stages in investment cycles across licensees, thus introducing volatility and inaccurate adjustments.

Benchmarking approaches for RIIO-ED1 made use, in places, of the full 13 years' worth of information that was provided by licensees. At RIIO-ED2 there will be cost information covering 18 years, for all 14 distribution companies, which should enable Ofgem to set challenging cost allowances upfront. We believe the benefits of making full and proper use of this wealth of information will far outweigh any perceived benefits of incrementally adjusting within period based on disaggregated unit costs. In addition this should place Ofgem in a very strong position with respect to the information asymmetry issues highlighted in the consultation document.

23. Do you agree with our assessment of IQI?

The analysis presented by Ofgem and CEPA shows an incomplete picture and, in the case of RIIO-ED1, fails to take account of the potential impacts of close-out mechanisms, which are likely to reduce the purported TIM benefits. Similarly, the analysis undertaken by CEPA on the possible benefits for each company had they bid their current view of totex at the time of submitting their business plans appears to have been done on a somewhat selective basis. CEPA appear to have held all other licensees' views of RIIO-ED1 expenditure at the level from their business plans and iterated one company at a time to their current in price control forecast. In reality, it is implausible that all companies could have gained from the IQI as shown by CEPA, given that the upper quartile would have moved and more than half of the companies would therefore have been above this revised benchmark.

The analysis and narrative also tend to the conclusion that outperformance of allowances is as a result of 'overbidding' rather than as a result of licensees responding to the challenges presented to them and driving cost and operational efficiencies. For UK Power Networks, this outperformance so far has been a result of incentives and innovations such as Light Detection and Ranging (LiDAR) and linkbox blankets, as well as the insourcing of ground works which have led to cost savings and different delivery models. Assumptions from both licensees and Ofgem at the time of making submissions and setting the price control can change over time, and as noted above, the RIIO-ED1 price control contains a number of reopener mechanisms to address this which will be subject to a close-out process at the end of the price control. Based on current numbers, it is likely that a proportion of current RIIO-ED1 outperformance will be returned to customers as part of this process, as happened at the end of DPCR5.

It is not in customers' interests for a company to blindly spend what it was allowed by Ofgem, and companies should always seek to outperform, whilst delivering their outputs in order to deliver the best cost solution, and thereby reduce customer bills whilst meeting their wants and needs.

24. Do you agree with our assessment of fast-tracking?

We broadly agree with Ofgem's assessment of fast-tracking across the respective sectors. We acknowledge the high level of rewards accruing to the fast-tracked company in RIIO-ED1 and recognise many of the perceived benefits of the competitive elements that fast-tracking engendered. We accept the difficulty with putting precise values on the benefits and costs to customers of fast-tracking and as such, whilst we may not fully agree with the specific values, we believe that is beside the point.

Our view is that there should be a comprehensive reward element which effectively replaces the fast-track reward that was employed in RIIO-ED1. For RIIO-2, we believe the incentive should come in two parts:

1. **The quality of plans** – licensees should be rewarded for putting forward challenging and well-justified plans; and
2. **Performance in the previous price control** – recognising licensees for frontier revealing performance from the RIIO-1 controls which will enable Ofgem to set more stringent cost and incentive targets for the benefit of all GB customers.

This is illustrated in Figure 6 below. That is, a good performing company should receive the base cost of equity, a form of reward for recognising both the quality of the RIIO-2 business plans, and for revealing true performance in RIIO-1, in addition to performance against allowances and incentives in RIIO-2.

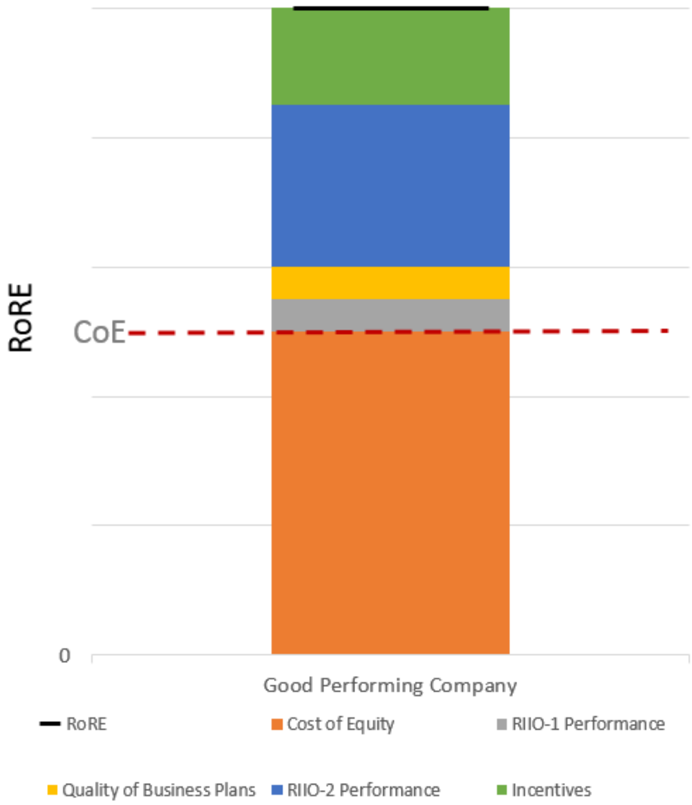

Figure 6 – Diagram showing the breakdown of Return on Regulated Equity and its components

Therefore, for this to be realised, Ofgem must specify upfront what good performance is. We recognise that this idea will need refining, and the relative size of the respective elements will need full consideration, particularly how the benchmarking for RIIO-2 and subsequent cost allowances interacts with the RIIO-1 performance element. Additionally, the emphasis placed on the revealed performance element versus the other elements may vary over successive price controls. Given that this idea is being proposed within the RIIO-1 controls it may be argued that its effectiveness will not be as great as if it had been in place at the start, which is particularly pertinent for the controls that are due to be reset in 2021. Nevertheless, we believe there are benefits to recognising good performance and believe it should include the following characteristics:

- Lowest cost;
- Best customer service;
- Enabling the energy transition;
- Sustainability; and
- Reliability.

25. What are your views on the options we have described?

- **How might these apply in the different sectors?**
- **Should we retain the IQI, amend it or replace it entirely?**

Moving forward, we agree that fast-tracking is unlikely to be viable in transmission, be that for ET, GT or the G/ETSO. In our RIIO-2 Open Letter response, we outlined a proposal to moderate the impact of fast-tracking, but given the further discussions that have taken place and the proposals included in this consultation we now favour a simpler approach for RIIO-2, whereby fast-tracking as operated at RIIO-ED1 is removed. Of the options presented, we favour Option 3 – the single business plan incentive. Further, we note the range of IQI options presented by Ofgem at their Fair Returns workshop on 28 March 2018 and believe further work is required to ascertain the relative incentive properties of each option. Options that move to a 100% allowance based on Ofgem's view of costs will place a greater emphasis on Ofgem getting its cost assessment 'right', as will any move to asymmetric sharing factors, where the point of inflexion becomes more contentious.

<u>Option 1 – Retain but amend the IQI</u>

The IQI matrix for determining the sharing factor provides upfront visibility for all. One benefit for RIIO-ED1 was Ofgem being clear to DNOs on the form their IQI would take, and the broad range of parameters in it. We note that in RIIO-ED1, the breakeven point was set at the most challenging level to date in Ofgem's use of the IQI.

We would be supportive of simplifying the IQI or such equivalent, and therefore improving transparency and simplifying the price control, provided that this simplification is not done in an arbitrary manner.

<u>Option 2 – Retain fast-tracking</u>

For RIIO-ED1, the fast-track process enabled a reduction in total customer bills of £2 billion through the competitive dynamic created, and by encouraging DNOs to submit ambitious business plans[23].

We share Ofgem's concerns that the level of financial benefit of fast-tracking ends up being higher than expected, and support mechanisms to clawback such benefits if justified.

[23] https://www.ofgem.gov.uk/ofgem-publications/84600/assessmentofriio-ed1businessplansletter.pdf

Option 3 – Single business plan incentive

The single business plan incentive is conceived to be a mixture of fast-tracking and the IQI – to incentivise companies to submit well-justified business plans. However, it is not clear how this would marry up with some of the RAMs, i.e. hard cap and collar, discretionary adjustments and anchoring, which may likely dilute any efficiency incentive rate.

Furthermore, it is dependent on qualitative assessment of business plans from CEGs and the RIIO-2 Challenge Group, which could invite legal challenge – see our proposal below in response to question 26. It would be useful to understand how Ofgem intends to mitigate challenges on subjectivity. We would be happy to participate in the workshops that Ofgem plans to hold on this concept.

We note that in the water sector, the regulator has, in its development of ideas for PR19, put forward proposals which could lead to a 'rush to the bottom' whereby licensees are unduly incentivised to put forward potentially overly optimistic plans. We believe Ofgem's traditional approach of strong, symmetric sharing factors, coupled with powerful incentives on the things that matter to customers, will deliver better outcomes for customers. We note that Ofgem's RIIO model is held in high regard internationally, whereas other regulators' models are less noticeably referenced.

26. What factors should we take into account when assessing plans for example, under fast-tracking (option 2) or a single business plan incentive (option 3)?

Under Option 3, there will need to provide clarity upfront on how the business plan incentive will be calibrated, taking into account revealed RIIO-1 performance, CEGs, RIIO-2 Challenge Groups, Open Hearings and Ofgem's own views. Care and attention should be paid to ensure that licensees' enhanced stakeholder engagement work is not undone and negated. Irrespective of which option is employed, the rules must be clearly laid out in the sector specific strategy decisions. Particularly where more subjective approaches are utilised, for Ofgem's control to have legitimacy in the eyes of all parties, the parameters for deciding what does and does not qualify for a reward should be clear and unambiguous.

27. Do you have any views on the factors we should take into account when deciding how to differentiate efficiency incentives for companies if we do not use the IQI?

At this point in time, if the IQI is to be replaced, we are inclined to favour a clearly set out framework for how efficiency incentives should be calculated, which is likely to be based on the results of Ofgem's totex benchmarking. More qualitative factors would be reflected in the level of any reward, given under our suggested business plan incentive, as set out in our response to question 24.

28. Is an explicit upfront financial reward required to incentivise companies to submit high quality business plans, in addition to differential incentive rates or sharing factors?

The fast-track process has its advantages. Ofgem, by its own admission, saw business plans come in at a total of £2 billion less between fast- and slow-track submissions for RIIO-ED1. The fast-track process has enabled licensees to put in more ambitious business plans, resulting in substantial savings to customer bills. Our suggestion for an overall business plan incentive which, in part, reflects the quality and ambition of RIIO-2 plans, should continue to provide strong incentives on licensees to focus on delivering high quality business plans.

29. Do you have any views on our proposal to remove fast-tracking for transmission?

Given the lack of comparators within the transmission sector, we agree with Ofgem's proposal to remove fast-tracking for transmission. At this stage, we are unclear why GDNs are required to submit two iterations of their business plans in relatively quick succession, whereas TOs are not.

30. Do you have any views on how we propose to incentivise better business plans from transmission companies, including removing the prospect of an upfront financial or procedural reward and placing greater reliance on user and consumer engagement and scrutiny?

Whilst we agree with Ofgem's proposal to remove the fast-tracking element for transmission companies due to a lack of comparators, we believe there are areas of transmission that are suitable for benchmarking against electricity distribution unit cost activities, such as asset replacement. For instance, 132kV is treated as a transmission voltage in Scotland, while in England and Wales, it is considered a distribution voltage. The numerous other comparators in the electricity distribution sector would undoubtedly drive more accurate cost assessments in areas of commonality and ought to be in customers' interests.

Care will be needed to ensure that the user and consumer engagement provides a robust challenge to TOs and does not result in a 'lighter' approach being applied at transmission. We note already an apparent additional burden on GDNs in having to provide two versions of their business plan versus only one in transmission. Given the sums involved and the particular danger of asset stranding at the transmission level, as more energy is generated from distributed generation, we would expect transmission to face at least the same degree of scrutiny as distribution.

31. How can we best improve the suite of annual reporting requirements to be as efficient and useful as possible?

We would welcome greater coordination from Ofgem to streamline the reporting demands on network companies, particularly to provide transparency on how some of the more detailed data is or will be used by the regulator.

- **Streamline or rationalise reporting across the suite of reporting requirements**: We suggest DNOs provide a list of the regular reports that are submitted to Ofgem and pinpoint where there are clear overlaps. An example of this would be the Environment & Innovation commentary which is part of the Regulatory Reporting Packs (RRP) due in July, and the Environment Report due in October. Ofgem will also need to ensure that the introduction of RIIO Accounts does not overlap with the new "Strategic Commentary" which will accompany the Cost & Volumes workbooks from 2017/18 onwards.

- **Provide consistent data definitions, formats, methodology and templates**: Where Ofgem believes they will require certain data sets for the RIIO-ED2 business plan submissions, these should be included where possible and relevant, into the current RIIO-ED1 RIGs. Any changes to the RIGs would go through a working group and a formal consultation which enables all stakeholders to share their views ahead of any additional requirements being introduced. Where there are clear benefits to adding to or amending the actuals reporting in order to better prepare for RIIO-ED2, this should be considered. More coordination from the regulator to streamline some of the demands on network companies would be most welcomed, in particular to provide transparency on how the more detailed data is or will be used.

- **Better transparency between expenditure and outputs**: This area should be explored within the relevant working groups, as there are clear benefits of aligning outputs to costs. This should be explored firstly without adding further reporting, i.e. look within the data already reported to see if there is scope to join up the two. For example, the secondary deliverable packs could, with limited work, be linked back to the costs reported in the main Cost & Volumes workbooks.

- **Establish a working group to work collaboratively to improve the reporting process**: We believe there is strong merit in setting up a working group, with one of its objectives being the activities suggested under "streamline or rationalise reporting across the suite of reporting requirements" as described earlier.

- **<u>Ensure that Ofgem only requests data which is eventually utilised and explain how</u>**: During the consolidation of reports, we also suggest making reference to reports, workbooks or tables within workbooks where it is not clear how the data or commentary is being utilised. Ofgem could then ratify the list, and where reports/data are not being used they should be removed from DNO reporting duties included throughout the remainder of RIIO-ED1. The advantage of finalising reporting sooner rather than later will be to provide clarity on definitions and ensure consistency amongst the DNOs, and therefore improve the quality and consistency of benchmarking.

32. How can we make the annual reports easier for stakeholders to understand and more meaningful to use?

We believe the Ofgem annual reports are of good quality. Ofgem being clear upfront at the start of the price control as to what it views as good performance would help stakeholders to understand the information presented and should improve the meaningfulness of reports. Furthermore, the Ofgem published infographics are particularly easy to digest, and their use should be explored more explicitly within the annual reports in order to clearly articulate network company performance.

33. What are your views on the policy objectives that we have defined with respect to the cost of debt?

We agree that customers should pay for no more than an efficient cost of debt and that companies should be incentivised to obtain the lowest cost financing without incurring undue risk. We accept that if a company is materially geared above the notionally assumed gearing, then it would be unreasonable for customers to fund these additional interest costs, unless it can be demonstrated that it is in their interests. However, we believe that it is vital for Ofgem to assess the actual debt costs of each company when determining the appropriate debt allowances. The use of any generic model may not capture the range of historic efficient decisions and hence would not be fair.

We agree that the cost of debt methodology should be transparent yet intellectually robust. The objective of simplicity needs to be balanced against the requirement to be fair to both customers and companies. We believe it would be inappropriate for an approach to be adopted which, while simple, resulted in companies being under-remunerated for their efficiently incurred debt costs or customers funding inefficient debt costs.

34. Which option might help to ensure that the approach to updating the cost of debt methodology delivers best value to consumers and why?

Option A (Recalibrate the RIIO-1 indexation policy) and Option B (A fixed allowance for existing debt plus indexation for new debt only) are both potentially viable options. However, we do not think Option C (Pass through allowance for debt) is viable. Whilst we agree that companies have limited discretion over their issuance profile, we believe that it remains appropriate to place incentives on them to ensure that they seek to fund debt as efficiently as possible. If debt costs are treated as a pure pass through then companies would have no incentive to innovate to minimise those costs, for example with the use of derivatives.

The main benefit of cost of debt indexation, and the underlying principle of Option A, is both its simplicity and transparency. This approach is well understood, the data is publicly available and it can be codified relatively easily. However, it can create arbitrary winners and losers based purely on the issuance profile of each company. With respect to UK Power Networks, a significant proportion of our debt portfolio was issued outside of the current index window. This historic embedded debt is higher cost than debt issued today, however, we have previously demonstrated to Ofgem that it was issued efficiently in line with industry benchmarks. We do not believe that it is either fair or reasonable that the indexation approach does not fully remunerate these costs.

Ofgem has set a range of proposals to modify the existing cost of debt index – we do not agree and list our reasons below.

For electricity distribution, we do not believe that it would be appropriate to change the current RIIO-ED1 trombone approach to the calculation of the trailing average. As was demonstrated at the time of the RIIO-ED1 determination, a shorter trailing average period did not sufficiently remunerate companies to cover their debt costs.

With Option A, Ofgem is also considering whether to adjust the cost of debt allowance on the basis that companies will outperform the relevant index. Whether this outperformance (also known as the "HALO" effect) existed was an area of disagreement between Ofgem and the companies at RIIO-ED1. Therefore, before making any adjustment Ofgem should set out its analysis so it can be independently reviewed. If any adjustment is to be made, Ofgem must also make an explicit allowance for transaction costs.

Another assumption that Ofgem is reviewing is whether the index should be based on A rated benchmark debt only, rather than the current approach which takes the average of A and BBB rated debt. This proposal is linked to the credit rating that Ofgem is targeting, which it has not yet defined. It would be inappropriate for Ofgem to use A rated debt to set the benchmark if the price control framework is targeting a BBB credit rating.

The main benefit of Option B is that it resolves the arbitrary winners and losers issue, as it funds companies' efficiently incurred embedded debt while still providing an incentive on them to issue new debt efficiently. The main issue with this approach is that it is more complex than Option A. It requires an approach to be developed to calculate the embedded debt costs, companies to demonstrate that their debt has been issued efficiently and it will require a form of true-up mechanism to adjust for differences in the assumed and actual levels of new debt. For the avoidance of doubt, we expect that the embedded debt costs will be calculated for each company and not based on an industry derived benchmark. The latter would be another form of index and would also create arbitrary winners and losers. We also believe that in deriving the cost of embedded debt the impact of RPI swaps should be taken into account. In setting the price control the regulator assumes that a certain percentage of a company's debt book will be index linked. A cost efficient approach to achieve the optimal level of index linked debt is to issue nominal debt and swap it into index linked debt. This should be recognised when calculating a company's embedded debt costs.

Our opinion is that Option B would be the approach that best meets Ofgem's objectives with respect to the cost of debt, if the issues identified above can be resolved.

35. Do you agree with our proposed methodology to estimate the cost of equity?

We agree that:

- The Capital Asset Pricing Model (CAPM) remains the most appropriate methodology to determine the cost of equity; and
- Determining the Total Market Return (TMR) based on long run historic data remains the most appropriate approach for this parameter.

We do, however, have significant concerns over CEPA's approach to the calculation of the components of the cost of equity. Our concerns with CEPA's approach are highlighted below. At a fundamental level, any derivation of the cost of capital should result in a situation where the risk premium for equity is higher than debt. This is logical as it is the equity holders in the business who bear the risks. The analysis undertaken by Oxera (shown in Table 2 below) demonstrates that CEPA's proposed parameters do not meet this test[24]. In none of the cases does the asset risk premium exceed the debt risk premium and at the low end of the

[24] https://www.oxera.com/getmedia/b31ba568-7c79-4d21-96f5-19b5e5d05e60/ENA-cost-of-equity_2018-02-28.pdf.aspx?ext=.pdf

proposed range the asset risk premium is substantially less than the debt risk premium. Such an outcome casts significant doubt on the validity of the proposed CEPA estimates.

Parameter	RIIO-2 proposals—low	RIIO-2 proposals—high	RIIO-2 proposals—mid-point
Real risk-free rate	-1.75%	-0.6%	-1.2%
Real cost of debt	0.30%	2.15%	1.2%
Equity risk premium	6.75%	7.10%	6.9%
Asset beta	0.25	0.40	0.325
Asset risk premium	**1.7%**	**2.8%**	**2.3%**
Debt risk premium	**2.1%**	**2.8%**	**2.4%**

Table 2 – Implied asset and debt risk premium based on CEPA's proposals[25]

Derivation of the Total Market Return (TMR)

We agree that the estimation of the TMR should take into consideration a wide range of information sources to develop a possible range. However, in determining where in the range the TMR lies, consideration must be given to the strength of the evidence associated with each source. A number of regulators including the CMA have used the TMR estimates produced by Dimson, Marsh and Staunton to inform their proposals. With respect to the latter, the 2017 Dimson Marsh and Staunton analysis of real UK long run TMR gives a value of 7.3%. This value is significantly higher than the upper end of the range CEPA have estimated, i.e. 5.0% to 6.5%. We agree with the analysis by Oxera that it could be argued that some weight should be given to the view that the increase in the Equity Risk Premium (ERP) has not fully offset the decline in the Risk Free Rate (RFR), and as a result, for the purpose of establishing a range for RIIO-2, an attenuated TMR of up to 6.5% should be assumed for the top end of the TMR range.

We also agree that forward looking approaches can provide a useful cross check on the values derived from the CAPM. However, it is vital that such models are properly specified; in particular, the choice of dividend growth rate will have a substantial impact on the resultant forecast TMR. The real TMR range calculated by CEPA's Dividend Growth Model (DGM) is 4.3% to 4.8%. The TMR derived by the Oxera DGM model (which is based on the Bank of England DGM) forecasts a TMR of 7.5%. This further supports that the TMR should lie in the upper end of the CEPA range. We agree with the Oxera estimate that, based on the range of evidence available, the TMR lies in the range 6.0% to 6.5%. The main differences between the two models are:

- **Short-term growth assumption –** CEPA's analysis is based on the Office of Budget Responsibility's (OBR) Economic and Fiscal outlook projections. On the other hand, Oxera's specification of the DGM is based on Institutional Brokers' Estimate System (IBES) forecasts of dividend growth for the FTSE All-Share index, which provides a direct measure of expected dividend growth.

- **Long-term growth assumption –** CEPA's analysis is based on the historical real UK GDP growth (4.5%, nominal). On the other hand, Oxera's specification of the DGM utilises weighted average international GDP growth forecasts, where the weights represent the proportion of revenues generated by FTSE All-Share companies across different regions (5.6%, nominal). The growth rate assumption used by Oxera is higher since companies listed on the London Stock Exchange are generally exposed to international markets, which have higher GDP growth rates on average than the UK.

In our view, Oxera's assumptions are more credible and hence its DGM estimate is more realistic. This further supports that the TMR should lie in the upper end of the CEPA range. We agree with the Oxera estimate that, based on the range of evidence available, the TMR lies in the range 6.0% to 6.5%.

In its consultation document Ofgem makes reference to the 5% to 6% range for the TMR inferred in the UK Regulators' Network (UKRN) report. An issue with the UKRN approach is that it is based on a geometric

[25] Oxera analysis of CEPA's estimates presented in CEPA (2018), 'Review of cost of capital range for Ofgem's RIIO-2 for onshore networks', February, Table 7.1.

mean rather than the arithmetic mean. As Oxera note in their report, there is a substantial body of evidence that supports the use of the arithmetic mean over the geometric mean as the appropriate methodology for estimating the long term TMR. In its report Oxera has highlighted two issues with Ofgem's interpretation of the UKRN report. These are:

- Ofgem implicitly assumes that regulators will set returns on a consistent basis over a relatively long time horizon; and
- Ofgem's (and CEPA's) deduction of the forward looking differential between RPI and CPI is not NPV-neutral and would be a structural break in the regulatory methodology towards the cost of equity.

With respect to the latter, investors have committed capital to UK regulated utilities based on RPI-linked returns and expectations about the level of nominal returns that could be generated. By assuming that investors evaluate returns in CPI terms and then deducting the full forward looking RPI-CPI wedge the nominal returns to investors will be lowered significantly.

Derivation of the asset beta

In its analysis on the appropriate asset beta, CEPA has derived an initial range of 0.25 to 0.35 which it has extended to 0.40 to cater for the impact of large investment programmes. CEPA notes that its original range aligns with Ofgem's proposed range for DPCR5. The 2014 CMA determination for Northern Ireland Electricity (NIE) set a range for the asset beta of 0.35 to 0.40 and selected a value of 0.40 (the upper end of the range) for its final point estimate. Additionally, the Utility Regulator for Northern Ireland used an asset beta of 0.38 in its June 2017 determination for NIE. Both of these values are at the upper end of the CEPA range.

As Ofgem has noted, the report from the UKRN has focused significantly on the methodology for estimating beta. A number of reports' authors have advocated using more sophisticated modelling techniques, namely the GARCH approach, and we note that Ofgem intends to implement this proposal. However, as is also noted in the UKRN report, the proposed approach is only one of a number of methods that could be used to estimate beta and there is no analysis presented as to why the GARCH approach is superior to these other methods or the existing approach. Before any specific weight is put on the GARCH methodology, it is important that the robustness of this approach is demonstrated for regulatory price setting. As was also noted in the UKRN report, the complexity of the GARCH approach may explain why it has not been used in regulatory or commercial estimation to date. Whichever method, or methods, are used to set the beta, we would expect Ofgem to clearly set out how it has determined:

- The sample of companies used to determine the beta;
- The time period over which the beta in its chosen sample has been estimated;
- What period the beta has been averaged over; and
- What frequency of data should be used.

The current beta analysis available is primarily focused on water companies. CEPA has stated that it considers the systematic risk in the electricity sector as broadly comparable to that in the water sector, i.e. that there is no difference in relative risk between the sectors. It is widely recognised that the energy sector is undergoing a period of significant change. Ofgem recognised this in its recent blog stating "*With unprecedented change in the energy landscape and how we use and generate energy, the role of energy networks is changing fast*" [26]. Given the latter, it does not seem likely to us that there is no difference in relative risk between the two sectors. In addition, due to the lack of energy network companies within the current beta data set of the CEPA report, the Oxera report has examined the asset betas for comparable

[26] https://www.ofgem.gov.uk/news-blog/our-blog/responding-changes-energy-network-usage

European energy network companies, which typically had asset betas at the upper end of CEPA's range. We also note that in Appendix F of the UKRN report, European comparators have also been included in the sample used to analyse asset betas in the energy sector. Based on the available evidence, our opinion is that the asset beta in the energy sector is higher than that in the water sector and would lie towards the top end of the range suggested by CEPA.

Approach to re-levering the asset beta

CEPA's approach of using a different notional gearing for the low and high case is unusual, with 65% for the low case and 50% for the high case. Regulators have typically chosen the same notional gearing for their high and low cases to allow for a simpler comparison of other elements of the cost of equity calculation. The notional gearing for electricity distribution is 65%. If CEPA's high estimate is aligned with this level, as shown in the Table 3 below, then the equity beta rises to 1.1%. We note that Ofgem has stated that it does not believe that the equity beta for regulated energy companies can be greater than one. However, it is important that Ofgem differentiates between the asset beta and the equity beta. In financial theory, the equity beta rises with leverage and a company with a low asset beta can see its equity beta rise above one, once leverage reaches a high enough level. Therefore, to improve both clarity and comparability, we believe that a constant assumption of notional gearing should be used in the derivation of any future estimates of the cost of equity.

	CEPA low	CEPA high	CEPA high (re-geared to 65%)
Gearing	65%	50%	65%
Asset beta	0.25	0.40	0.40
Equity beta	0.71	0.8	1.1

Table 3 – CEPA's gearing ranges

Other cost of equity issues

We do not agree with the proposal to calculate a Regulatory Expected Return. The underpinning tenet of this approach is that all companies will outperform the price control settlement and, importantly, that Ofgem can predict what this will be. Ofgem should set a Regulatory Allowed Return (RAR) that remunerates a company for meeting the targets (both cost and output) and it should not adjust that RAR to take into account its estimate of expected outperformance. Given that Ofgem incentivises companies to outperform the price control targets, it should not come as a surprise that companies are outperforming. The key issue appears to be scale of outperformance. This is not an issue with the cost of capital, but with how Ofgem sets cost and output targets. Ofgem should focus its effort on appropriately incorporating the observed actual company performance into its target setting methodologies, rather than assume it will get it wrong and seek to clawback, through the allowed cost of capital, any perceived error.

Ofgem also states that it will have regard to the observed Market to Asset ratios (MARs) for quoted utility companies and the returns bid by investors for assets such as Offshore Transmission, when assessing the outputs of the CAPM. With respect to the former, NERA have carried out an analysis for National Grid[27] which highlights that real RAV growth, the impact of non-regulated/non-UK activities and outperformance of the current settlement can explain the current observed MARs. With respect to the implications of the bid outcome on Offshore Transmission, these schemes have a different risk profile to network utilities. For example, the Offshore Transmission regime awards contracts which have the following characteristics:

- Fixed 20-year revenue stream which is RPI linked;

[27] "Implications of Observed Market to Asset ratios for Cost of Equity for RIIO-T2" NERA, 1 December 2017

- No risk of regulatory reset;
- No construction risk; and
- Financing can be largely completed upfront, implying limited refinancing risk.

Ofgem must demonstrate how it has normalised for these factors before comparing the cost of equity from Offshore Transmission to its calculated value for the cost of equity.

36. Do you agree it would be desirable to index the cost of equity?

- **Do you have views on our proposal for indexation?**

While we can see some merit in the indexation of the cost of equity, we remain unconvinced that it is necessary to do so in RIIO-2. The introduction of a cost of equity index will add further complexity to the price control and contradicts Ofgem's RIIO-2 objective of simplification. We believe that the move to a five-year control appropriately mitigates the forecasting risk and hence we remain unconvinced that indexing the cost of equity is necessary at this point.

However, we have reviewed Ofgem's preferred approach to a possible cost of equity indexation mechanism. We agree that any such mechanism must fix both the TMR and equity beta. This effectively assumes a perfectly negative relationship between the RFR and ERP – though Ofgem has yet to provide sufficient evidence to justify this assumption. This is an area which, if implemented, would require further work. A move to cost of equity indexation would represent a considerable change in methodology. Any adoption of an indexation methodology needs to be appropriately signalled and introduced with appropriate transitional arrangements such that it does not undermine investor confidence.

37. Do you consider there is merit in removing the indexation of the RAV and adopting a nominal return model in RIIO-2?

- **What would be the benefits and drawbacks?**

The impact of changing how the inflation element of the cost of capital is funded is that it changes the balance of funding network costs between existing and future customers. If regulatory depreciation is on a straight line basis then adding the inflation element to the RAV ensures that over the life of the asset, customers pay the same amount in real terms per annum. Removing the indexation from the RAV will mean that existing customers will pay more in real terms than future customers. This may raise issues of inter-generational equity.

It will also be important to consider the impact on how index linked debt is treated by the rating agencies under this proposal. A number of adjustments are made by the rating agencies to recognise that inflation linked debt moves in line with an inflation linked asset. A move to funding the inflation element of the cost of capital in year may result in the rating agencies changing their methodologies and hence the assessment of whether a company is financeable. Also, companies with index linked debt and derivatives will need to change their liabilities, which will be an expensive one-off cost. This may increase overall costs to customers. We would expect Ofgem to produce a comprehensive CBA showing the full costs and benefits to all parties before it undertook any such change.

38. Should the onus for ensuring financeability lie with the network operating companies in whole, or in part?

In paragraph 7.67, Ofgem recognises that it has a duty to ensure that companies can finance their activities, and we would argue that Ofgem has a responsibility in this area as well. It is incumbent on Ofgem that its approach to the cost of capital is, demonstrably, both fair and reasonable and takes into account the long-term investment requirements of the electricity distribution businesses. It would be helpful if Ofgem could set out its view on the credit rating it is targeting, how it proposes to stress test these metrics and how it might respond if any proposals lead to sector-wide downgrades. Our view is that Ofgem should continue to target a comfortable investment grade credit rating given the critical role that energy infrastructure plays.

We accept that companies also have a financeability responsibility. For example, if a company has decided to operate a capital structure with gearing significantly above the assumed notional gearing, then any financeability issues caused by this choice are for the company to resolve, not customers.

39. Do you consider the introduction of a revenue floor, to protect the ability of companies to service debt, to have merit?

It would be helpful if Ofgem could set out further detail on the mechanics of this proposal so that its impact could be understood, but clearly it is not in the interests of customers or society if a network company were to become insolvent. However, at a high level it appears that under this proposal, if the allowed cost of capital is insufficient for a well-run company to maintain its investment grade credit rating, revenues will be increased to achieve this, with the revenue to be paid back in later periods. One of the approaches discussed is the restriction of dividends in future periods. Under this approach, the onus for resolving financeability issues would appear to fall predominantly on the companies. If investors are subject to significant periods where they cannot receive a dividend then this will impact on the perceived riskiness of the sector and ultimately raise the cost of capital.

40. Do you agree that Ofgem should review the causes of any variances between tax allowances and taxes actually paid to HMRC (including the treatment of group tax relief)?

- **Which of the options described in this consultation may be worth investigating further to address any material variances?**

We agree that Ofgem should review whether there has been a material deviation between the tax allowances and tax paid before it attempts to devise mechanisms to resolve any perceived issue, recognising that the situation may vary across sectors. If a mechanism is required then Ofgem should consider utilising a dead band approach within its mechanism to cater for non-material variations. This would simplify any proposed methodology and is the approach used for the current tax clawback mechanism in RIIO-ED1.

41. Do you agree that we should move away from RPI for RIIO-2 (including for the indexation of the RAV if retained as a feature)?

- **If yes, which of the two potential indices – CPI or CPIH – might be most suitable?**
- **Is a phased transition between RPI and the chosen successor index necessary or desirable?**

We understand that from a customer perspective, CPI or CPIH may be a more legitimate inflation metric than RPI and would improve the transparency and legitimacy of those charges for our customers.
In our response to the RIIO Open Letter we set out three main issues that must be resolved to facilitate the desired change in indexation approach. They are:

- **Determining a CPI (or CPIH) stripped cost of capital**: The current approach to calculating the real cost of debt is to deflate the relevant iBoxx index with RPI breakeven inflation. Calculating a CPIH stripped version requires a determination of the wedge between RPI and CPIH. The choice of methodology for determining this wedge will be subject to regulatory judgement and therefore introduces an additional element of uncertainty into determining the appropriate cost of capital. For investors to have confidence that the change in inflation is present value neutral, Ofgem should set out in advance and in detail how it would translate from an RPI based cost of capital to a CPIH based cost of capital.

- **Mismatch between debt and RAV accretion**: Another impact from the change in inflation index is the mismatch that it could create between a RAV that indexes in full or in part with CPI (or CPIH) and a regulated company's long-term RPI-denominated index linked debt. Differences in the rate of growth in a company's assets and liabilities could have adverse consequences over both short and long horizons. For example, in the longer term, one of the rationales for borrowing on an index linked basis has, until now, been that the principal owed to lenders would grow at the same rate as the regulated asset base. If debt grows more quickly than RAV, companies' index linked borrowing may look less sustainable, in particular when the expected differential compounds over the 30 or 40 year tenor that is left on some companies' RPI linked bonds. CPI (or CPIH) indexation may also negatively affect companies' financeability. Specifically, we note that Moody's have commented that it may no longer be appropriate for the accretion element of this debt to be fully excluded from the interest coverage calculation.

- **Impact of the loss of access to index linked debt**: A shift to CPI (or CPIH) indexation may cut regulated companies off from new RPI linked debt at a time when there is no significant market for CPI (or CPIH) linked debt. If companies cannot realistically issue new index linked debt, and if RPI linked debt (or a mix of index linked and nominal issuance) is cheaper than issuing only nominal debt, a change in indexation method would increase industry financing costs. This would be to the disadvantage of customers as it would increase the cost of debt and ultimately costs to customers. A solution may be to swap the RPI debt into CPIH linked debt. However, this will also increase financing costs and hence costs to customers.

With respect to the first point above, it would be helpful if Ofgem could set out its proposed approach. This is vital if investors and other stakeholders are to be convinced that the impact of the change is present value neutral. We also believe that there is a lack of clarity on a range of issues (including those listed above), which means that at this stage it is difficult to evaluate what sort of transition mechanism, if any, may be required.

42. In the light of our proposal not to amend, at a price control framework level, our policies for depreciation and asset lives set in RIIO-1 do you have any views or suggestions that you wish to put forward?

The choice of asset lives, and hence depreciation rates, is linked to the overall assessment of the financeability of the price control. While we expect them not to change, we believe that companies should have the opportunity to propose alternatives if it can be demonstrated that the proposals are in the interests of customers.

In its evidence to the CMA, Ofgem stated that one issue of concern was in relation to inter-generational equity in relation to asset lives. Ofgem stated that it would review its current RIIO-1 proposals in this area at RIIO-2 to better understand if such issues were material. Given Ofgem's decision not to change its position on asset lives, it would be helpful if it could publish the analysis that has supported this decision.

43. We propose to review the fast/slow money split at the business plan submission stage, do you have views that you wish to put forward at this stage?

The split between fast and slow money has been another important financeability tool in previous price controls. In RIIO-ED1, companies were able to propose their own fast and slow money split as part of their business plan submission and we believe that this should be the approach for RIIO-ED2. We would expect Ofgem to review the proposed split to ensure that it is in customers' interests. Ofgem should be clear in advance of business plan submissions of any 'red lines' it has with respect to fast/slow splits.

44. Do you think existing mechanisms for providing allowed revenue to compensate for the raising of notional equity are appropriate in principle and in practice?

No comment.

45. What are your views on each of the options to ensure fair returns we have described in this consultation?

We have examined each Return Adjustment Mechanism (RAM) in turn, against a number of regulatory principles in the Table 4 below, along with an overall ranking.

	Incentive properties	Innovation	Ease of operation	Legitimacy	Financeability / Risk	Dispersion of performance	Legal Challenge	Guaranteed Fair Returns	Rank
1. Hard Cap/Floor									**5**
2. Discretionary adjustment									**6**
3a. Constraining totex (sculpting totex) with incentives individually capped and collared									**1**
3b. Zero sum incentives									**4**
3c. Fixed incentive pot									**3**
4. RoRE sharing factor									**2**
5. Anchoring									**7**

Table 4 - Return Adjustment Mechanisms examined in relation to regulatory principles

<u>**Hard Cap/Floor**</u>

<u>Incentive Properties:</u> We agree with some of the points outlined by CEPA, but note it could run counter to Ofgem's desire for a dispersion of performance. As NWOs approach the cap, a NWO incentive to improve performance diminishes and so may choose not to do so. Therefore, customers could receive a poorer service at a higher cost. Furthermore, Ofgem could see itself intervening to deal with licence breaches as a floor would reduce the effectiveness of penalising poor performance.

Innovation: This will stifle innovation as the opportunity for greater returns is curtailed, effectively dis-incentivising further company outperformance. A network company would not seek further innovation savings if its revenues had reached the cap.

Ease of Operation: This would be relatively straightforward to operate, either annually or trued up at the end of a price control period.

Legitimacy: Ofgem would be able to ensure that returns have not breached an arbitrary line. The drawback would be guaranteed returns for network companies, irrespective of company performance, i.e. enough to service debt.

Financeability/Risk: This would remove individual caps and floors that already exist in RIIO-ED1. For example, IIS has a downside limit. An overall cap and floor would remove this and could potentially drive perverse company behaviour to pursue relatively easy outputs and incentives, and only to maintain minimum standards in other areas to avoid penalties.

Dispersion of Performance: Dependant on the width of the cap and floor band returns will be ensured and constrained to a certain level. Therefore, dispersion of performance will be artificially constrained.

Legal Challenge: Performance for individual licences and outcomes are independent of others. Therefore, reducing the likelihood of perennial challenges.

Guaranteed Fair Returns: All companies' returns in a sector may reach the cap (upside limit), meaning the industry average is above the original intended return but still constrained to the upside limit.

Discretionary adjustments

Incentive Properties: This is arbitrary, ambiguous and open-ended. Industry leading performance will be exposed to potentially subjective adjustments. This would have a detrimental effect on NWOs in pushing boundaries, effectively dis-incentivising stand-out performance.

Innovation: See the above paragraph on incentive properties.

Ease of Operation: To mitigate detrimental effects, this RAM requires significant upfront definition of what could be exposed to any adjustment and the corresponding reasoning, which in itself would stray from a truly discretionary mechanism. This could also entail significant work at the point of undertaking any such adjustment, with multiple parties all seeking to take advantage of the remaining ambiguity to press their respective cases.

Legitimacy: With no clear definition of what could be subject to a discretionary adjustment, there would be significant uncertainty for customers and companies. Furthermore, this RAM is susceptible to external pressures leading to inconsistent application of approach and outcomes.

Financeability/Risk: There are significant risks with this RAM. The regulator has the discretion to make ex-post adjustments. Therefore, this is likely to encourage conservative company performance and business plans. This ambiguity would also increase perceived risk, resulting in investors being likely to expect higher returns as the rules are not defined.

Dispersion of Performance: This is likely to be poor as companies will be incentivised to avoid outperformance in cost and/or output/incentive improvement. Performance outside of a range would be discouraged, leading to a tighter grouping of performance.

Legal Challenge: Ofgem may be more susceptible to legal challenge by licensees where such adjustments are made, and by other parties when Ofgem opt not to make adjustments, resulting in significant additional regulatory burden for all parties.

Guaranteed Fair Returns: This RAM would allow Ofgem to make adjustments as it sees fit to bring sector returns to a level it perceives as being legitimate at a given point in time.

Sculpting of totex sharing factor with incentives individually capped and collared

Incentive Properties: The incentive to outperform is reduced but not eliminated, as it retains properties to outperform. Existing incentive mechanisms operate in this way in RIIO-ED1 and have done in previous DPCR periods.

Innovation: As above, noting that the incentive rate is reduced, there still remains an ongoing incentive to find efficiencies through activities such as innovation to deliver outputs for lower costs than originally allowed.

Ease of Operation: The rules of the price control will be defined upfront. A small number of defined tiers could be easily applied. To simplify the process this could be delivered by applying it at the end of the control, or alternatively run annually with a final true-up at the end of the period. Individual incentive mechanisms will need to have clearly specified caps and collars, informed, where appropriate by stakeholder research, willingness to pay surveys and overall assessment of scope for outperformance.

Legitimacy: Licensees are remunerated for delivering improvements in outputs and delivering for lower costs. Where significant cost improvements are made, more of these savings are shared with customers, improving the legitimacy of RIIO.

Financeability/Risk: The rules of the price control are clear upfront. All parties are aware of how performance will be treated. There is clarity for stakeholders in how cost outperformance will be addressed. That is, there are no surprises for customers nor investors.

Dispersion of Performance: It does temper levels of outperformance and underperformance without artificially constraining the varying levels of performance. Whilst individual caps and collars on incentives may lead to convergence of performance, our proposals for updating incentive targets within period using benchmarked revealed performance, will still provide incentives for companies to deliver and differentiate themselves from their peers.

Legal Challenge: Performance for individual licences and outcomes are independent of others. Therefore, reducing the likelihood of perennial challenges.

Guaranteed Fair Returns: Whilst ensuring customers receive greater benefit of company outperformance, it does not fully guard against higher than average sector returns. This should also take into consideration how initial cost allowances may be set. Fully utilising the available data at RIIO-ED2 should put Ofgem in a strong position to set challenging cost allowances, which should reduce the likelihood of systematic outperformance. We note that the observed spread of cost outperformance in RIIO-ED1 shows that there is not systematic outperformance.

Zero Sum Incentives

Incentive Properties: By utilising a uniform incentive rate, this RAM is likely to negate the willingness to pay research that NWOs may individually undertake as part of developing their well justified business plans. It is unclear how this RAM would work with individual targets set in advance. Further, it is unclear how this interacts with a RoRE point, which is specific to individual companies due to the varying degrees of regulated equity. For example, for company A, one RoRE point could be worth £1 million, and for company B, one RoRE point could be worth £2 million.

Innovation: This would not apply to innovation, see the sculpted totex sharing factor section.

Ease of Operation: This could be complicated given the current explanation that it will be an annual ex-post assessment. Far more scrutiny and assurance would be required from Ofgem to understand how they would ensure consistency of application were this method to be employed. Relative incentives require stringent interpretation of standards to ensure consistent reporting, and they would also need explicit quantification upfront of the relative size and value of each associated incentive.

Legitimacy: As we understand this mechanism, it would be a fundamental departure from how Ofgem have traditionally employed incentive regulation – potentially, poor performing companies' customers would effectively pay strong performing companies, breaking the direct and fundamental linkage between a NWO and its own customers. If the sector is poorly performing, the "least bad" companies may still earn rewards, which may question the appropriateness of such mechanisms.

Financeability/Risk: A NWO will be unsure of its exposure until the end of the year and it is unclear how the "penalties" or the rewards will be distributed. Furthermore, there is the question of whether all incentives will now be symmetrical, having upside and downside, i.e. Stakeholder Engagement Consumer Vulnerability (SECV) is upside only in RIIO-ED1.

Dispersion of Performance: This does not inhibit a range of performance, although it does amplify relatively small differences and potentially unduly penalises relatively poor performance in a strongly performing sector.

Legal Challenge: Ofgem could be susceptible to legal challenge by licensees as small performance or interpretational differences could lead to a sizeable reward or penalty.

Guaranteed Fair Returns: Guarantees that incentives are zero-sum, but individual licensee performance and remuneration could be wildly different from that anticipated and communicated with customers.

Fixed Incentive Pot

Incentive Properties: Distorts the underlying incentive rates as this will be defined relative to other companies' performance. All incentives will need to be indexed – any incentive that is upside only, will have to be modified to take account of relative performance, i.e. will now have to have a downside.

Innovation: This would not apply to innovation, see the sculpted totex sharing factor section.

Ease of Operation: This would require significant work to set all targets upfront and their relative rankings, i.e. to convert, index and weight them. Far more scrutiny and assurance will be required of Ofgem to ensure all parties report consistently and particularly with respect to any qualitative incentives the assessment is fully transparent. This would introduce some additional complexity as the sum of all the respective incentives would need to be evaluated each year.

Legitimacy: Customers of the poorer performing companies will find themselves funding the rewards of those higher performing companies. By blending all of the incentive mechanisms together, it may create presentational issues for Ofgem in explaining how the overall strongest performer can perform poorly at the majority of incentives due to uneven weightings of incentives in this pot.

Financeability/Risk: Returns are dependent on the performance of other companies, there are potentially big swings in rewards as outlined in the CEPA document[28]. Comparing scenario one (£26.2m reward) and three (£56.5m reward) for company C – the reward has more than doubled for a one point improvement in overall score, indicating the potential volatility of such an incentive pot.

[28] https://www.ofgem.gov.uk/system/files/docs/2018/03/cepa_review_of_the_riio_framework_and_riio-1_performance.pdf, page 93.

Dispersion of Performance: does not inhibit variability in dispersion.

Legal Challenge: Ofgem will be susceptible to legal challenge by licensees as small performance or interpretational differences could lead to a sizeable reward or penalty.

Guaranteed Fair Returns: This will constrain the average sector returns, but as evidenced by CEPA's own examples, could create significant reward/penalty variations for individual licensees for minimal performance differences.

RoRE sharing factor

Incentive Properties: Combining both cost incentives and performance incentives will inevitably distort the underlying incentive rates of both elements. In addition, there are a number of incentives within RIIO-ED1 where the sharing factor does not apply, this would need to change in RIIO-ED2 under this approach.

Innovation: As above, noting that the incentive rate is likely to be altered, there should still remain an ongoing incentive to find efficiencies through activities such as innovation to deliver outputs for lower costs than originally allowed, albeit the precise sharing factor will not be known upfront, which may dampen the incentive to innovate.

Ease of Operation: The rules of the price control will need to be defined upfront. There would also be a need for an end of period true-up to account for overall cost performance over the entire period and any close-out adjustments that are required.

Legitimacy: Licensees are remunerated for delivering improvements in outputs and delivering for lower costs where significant improvements are made, savings are shared with customers, improving the legitimacy of RIIO. This RAM could dilute the outcomes of individual incentive mechanisms that were informed via stakeholder research, willingness to pay and overall assessment of scope for outperformance.

Financeability/Risk: The rules of the price control are relatively clear upfront. All parties are aware of how performance in aggregate will be treated. Clarity for stakeholders in overall cost and service performance will be shared with them. That is, there are no major surprises for customers nor investors, although the strength of individual elements may differ from that originally envisaged and communicated.

Dispersion of Performance: It does temper levels of outperformance and underperformance without artificially constraining the varying levels of performance. Whilst individual caps and collars on incentives may lead to convergence of performance, our proposals for updating incentive targets within period using benchmarked revealed performance, will still provide incentives for companies to deliver and differentiate themselves from their peers.

Legal Challenge: Performance for individual licences and outcomes are independent of others. Therefore, reducing the likelihood of perennial challenges.

Guaranteed Fair Returns: Whilst ensuring customers receive greater benefit of company outperformance, it does not fully guard against higher than average sector returns. This should also take into consideration how initial cost allowances may be set. Fully utilising the available data at RIIO-ED2 should put Ofgem in a strong position to set challenging cost allowances, which should reduce the likelihood of systematic outperformance. We note that the observed spread of cost outperformance in RIIO-ED1 shows that there is not systematic outperformance.

Anchoring returns

Incentive Properties: Potentially significant distortionary impact on underlying incentive rates and properties, across incentive mechanisms and totex. Incentives would be diluted if bands are not adequately wide.

Innovation: Likely to adversely impact the likelihood of licensees seeking out and adopting significant technological or operational innovations that yield major cost and/or performance savings, given the licensees share of such savings will be unclear.

Ease of Operation: As identified by Ofgem the mechanism could operate on an annual basis, however a significant true-up would need to be undertaken at the end of the period, to fully reflect the overall outturn from the price control, the operation of reopener mechanisms, any Network Output Measure (NOMs) Penalties and Rewards, etc. This, coupled with a cost of equity that may be indexed, and hence different each year, will further add to the complexity of this end of period true-up.

Legitimacy: On one angle of legitimacy – constraining returns to a sector average that was postulated at the time of setting the price control this option delivers. However, elsewhere in the consultation document Ofgem have made reference to "earned rewards" and on this view anchoring can be seen in an unfavourable light. Under some of the anchoring permutations being circulated by Ofgem, it is more than likely that circumstances will arise in one or more of the price controls where the sector average is below the anticipated level. In such circumstances Ofgem have indicated there will be an upwards revision to licensees returns. We believe this will merely shift the "legitimacy" debate from one over the size of returns to one around the basis for returns and anchoring has fatal flaws on the latter.

Financeability/Risk: This option creates a significant degree of additional financial risk compared to the framework currently in place in RIIO-ED1. As noted above a significant end of period true-up would be required to settle the final outturn positions for every licensee. Assuming a five-year price control with a two-year close-out process it could well be eight years before the final financial position is truly known by customers and licensees and the appropriate financial adjustments begin to take place.

Dispersion of Performance: Ofgem have recently shared with licensees three possible variants of how anchoring could be employed. In two of these, the emphasis appears to be on targeting anchoring adjustments at the higher performing companies. As such there is a significant risk that particular versions of anchoring could lead to more grouping of performance, which we understood was something Ofgem were trying to avoid.

Legal Challenge: Given the relative and perpetual nature of anchoring, it is highly likely that licensees and other stakeholders will take both a keener interest in and potentially be more likely to challenge, all major financial decisions that impact on other parties. Whilst this may be desirable from the perspective of increasing scrutiny of Ofgem decisions and allowances, performance targets, reopener adjustments, etc., it will significantly ratchet up the regulatory burden on Ofgem and the likelihood of one or more parties challenging such decisions.

Guaranteed Fair Returns: As noted above, anchoring could be crafted to yield both a constrained company and sector level of return, however nothing we have seen from Ofgem to date indicates that anchoring will deliver on the associated level(s) of performance that come with particular returns. There is a strong possibility that following initial "success" in constraining returns the fundamental flaws are revealed as anchored returns bear little or no resemblance to the cost and output incentive performance of licensees. As stakeholders begin to realise this and question Ofgem we fear the mechanism will implode, leaving Ofgem to face a huge question over legitimacy of the RIIO-2 framework.

46. Is RoRE a suitable metric to base return adjustments on?

- **Are there other metrics that we should consider, and if so why?**

Please see our response to question 45.

47. Do you have any views on the interlinkages and interactions outlined in this consultation and those that we will need to consider as we develop our sector-specific proposals?

Ofgem should give full consideration to any interlinkages and interactions between sectors. For example, there are impacts of anchoring on the whole suite of topics we have explored in our response; we have included a detailed example below:

With reference to Table 5 below, there is a theoretical whole system incentive rate at £1 per MW released initially. The cost to electricity distribution to release a MW is £0.90 and for transmission is £1.10. However, in a scenario where the electricity distribution sector outperforms, anchoring takes effect so that the effective incentive is reduced to £0.50 per MW, and perceived poor performance within transmission results in anchoring increasing the incentive to £2 per MW. That is, the whole system incentive is multiplied for transmission and diluted for electricity distribution. This causes correct decisions that were made at the beginning of the control to potentially be incorrect at the end of the control, due to the mechanics on which the original decisions were made being altered by the anchoring mechanism based on relative sectoral performance. The result being a lower cost solution at the start of the control, ultimately a higher cost incurred to customers at the end of the control.

	DNO (£)	**TO (£)**
Cost	0.90	1.10
Incentive (pre-anchor)	1.00	1.00
Incentive (post-anchor)	0.50	2.00
Net (post-anchor)	(0.40)	0.90

Table 5 – Example of anchoring on a whole system incentive

This could be mitigated with our suggestion of a *third pot* without relative RAMs – please see our response to question three.

48. Do you have any views on the issues highlighted that we will consider as we develop our sector-specific proposals?

In particular to the whole system, we believe there needs to be continued and coordinated cross-sector engagement, i.e. all sectors are involved with any development of proposals such that the appropriate mechanisms are put in place, albeit they may be implemented at later timeframes if start dates are not aligned.

To help facilitate this, it is imperative that Ofgem forms a position on the role and responsibilities of the TSO and DSOs now.

49. Are there any sector-specific issues or policy areas that we should ensure we review and consider as we develop our sector-specific proposals?

There are specific incentives and outputs to each sector. The following affect electricity distribution:

- Decarbonisation/electrification of heat;
- EVs;
- Targeted charging review;
- Vulnerability and most appropriate ways to address;
- DNO transition to DSO; and
- Energy efficiency.

We would welcome continued engagement with Ofgem and other parties on this front.

50. Do you have any views on our high-level proposals for timing of RIIO-2 implementation, and on our proposals for engagement going forward?

As an observer and potential User Group participant in the RIIO-T2 price control, we believe the timeline looks ambitious. That is, a lot is forecast to take place in a relatively short timeframe. The volume of reports (business plans, CEG and RIIO-2 Challenge Group reports, corresponding Ofgem assessments, and subsequent iterations, feedback, and possible Open Hearings) makes the timeline constrained. Potentially, this limits the full extent to which stakeholders can participate, as well as the ability for NWOs to deliver against all the requested criteria in the timeframe available.]
Specifically for gas distribution, if you consider that the sector specific methodology will only be provided in Q2 2019, the initial business plans are to be submitted in Q3 2019 and the final business plans are to be submitted in Q4 2019. GDNs appear to have tighter circumstances than transmission operators to refine their business plans, and allow sufficient time for CEG assurance. We would appreciate early sight of electricity distribution dates and timelines, and would expect that sector specific work for RIIO-ED2 would commence earlier than for RIIO-GD2.