7. NATIONAL GRID GAS TRANSMISSION RESPONSE TO RIIO-2 DRAFT DETERMINATION: FINANCE ANNEX

Introduction

National Grid Gas Transmission (**NGGT**) has serious concerns with Ofgem's RIIO-2 Draft Determination (**DD**) and its consequences for Great Britain. The DD cuts our proposed business plan baseline allowances from £2.6bn to £1.53bn and reduces the outputs we proposed in our business plan. Whilst we share Ofgem's stated objectives for RIIO-2, the DD currently fails to meet the needs of our customers and stakeholders and is not in the interests of current and future consumers because it:

1. **Introduces significant risk to the reliability and resilience of the network,**

2. **Creates unnecessary complexity and volatility in the framework, and**

3. **Erodes regulatory stability and investor confidence.**

We welcome the fact that Ofgem has clearly signalled this as a consultation in which it is open to making changes based on stakeholder views and through consideration of evidence. This is positive and important because we consider that a significant number of the proposals are currently unacceptable and numerous remedies are necessary for Final Determination to address the issues identified. We have therefore provided an evidence-based response, supplying new evidence where relevant and proposing remedies to the issues identified which better meet the interests of consumers.,

We will also continue to engage constructively with Ofgem over the weeks and months leading up to the Final Determination with a view to ensuring our evidence is fully understood and the necessary changes secured.

Structure of this response

There are seven parts to our response in which we provide the substantial evidence to justify and support the changes needed. This document forms our response to Ofgem's Finance annex.

1. A covering letter
2. An executive summary of our response
3. Our response to the Core Document
4. Our response to the Gas Transmission sector annex
5. Our response to the NGGT annex
6. Our response to the Network Asset Risk Metric (NARM) annex
7. **Our response to the Finance annex**

The rest of this document covers our response to the questions raised in the **Finance annex**. In addition, we have set out a summary of our concerns in the overview and further in the summary narrative, which focus on the DD introducing: **inadequate returns**; **a marked weakening of financial resilience**; and **unachievable allowed equity return**. These are drawn from the extensive stakeholder and consumer engagement we carried out on our business plan and, importantly, reflect both what our customers have told us they need and want us to provide, and what we require in order to be able to deliver for them.

Overview

Throughout the RIIO-2 process we have engaged with Ofgem and stakeholders on the critical importance of setting an appropriate financial framework. We have a shared goal with Ofgem to ensure that the framework improves stakeholder legitimacy and maintains investor confidence in the energy sector.

We recognise that changes to the framework are required in RIIO-2 to improve stakeholder legitimacy. It is right that returns are lower in RIIO-2 than they were in RIIO-1. We can also appreciate the benefit of introducing Return Adjustment Mechanisms (RAMs) into the framework to limit windfall gains and losses.

But instead of limiting changes to those necessary to maintain legitimacy, Ofgem are proposing to make fundamental changes to the RIIO-1 framework which will increase the very costs they are trying to minimise – namely the rate of return required to invest in an energy network. We have been clear on our disagreements with Ofgem's proposed framework through RIIO-2 consultations to date. Despite the substantial body of evidence that we have provided to Ofgem already to demonstrate the shortcomings in what has been proposed, many of our areas of disagreement remain in the DD. The financial package the DD sets out will create fundamental obstacles to our ability to deliver key consumer outcomes, including helping the UK on the pathway to net zero and will give rise to higher future bills.

At a summary level, our issues with the DD framework are that it introduces:

- **Inadequate equity returns:** The proposed allowed equity return is below that of the UK water sector and most comparable international benchmarks. This level of return is far too low for a transmission company, owing primarily to errors in setting both beta and total market return and the inclusion of a flawed outperformance wedge. Ofgem's proposed beta is not in line with the fundamental drivers of higher risk for energy compared to water, such as capex complexity, stranding risk and energy transition uncertainty. Nor does it take account of empirical evidence in the DD which shows National Grid plc's beta has been higher than the proposed beta and those of the water sector over the last ten years.
- **A marked weakening of financial resilience**: The lower returns in RIIO-2 sharply reduce financial resilience with baseline plans leaving the notional company on the cusp of being downgraded from Baa1 / BBB+, Ofgem's target rating. More worryingly, notional credit metrics drop to sub-investment grade once cashflow risk caused by delays between spend and revenue under uncertainty mechanisms is factored in.
- **Unachievable allowed equity return**: With the application of disproportionate and unjustified Business Plan Incentive (BPI) penalties, higher than ever efficiency cuts, and a flawed outperformance wedge, Ofgem has placed an unprecedented challenge on our business at the start of RIIO-2. As a result, equity returns would only be 2.7% without any savings to current operations, 150 basis points (bps) below the allowed equity return. With minimal potential upside from incentives and totex performance the framework offers unprecedentedly low opportunity to close the gap despite the need for innovation to deliver the energy transition. In combination, this means that investors cannot expect to deliver the allowed equity return - a fundamental tenet of the regulatory regime, which is clearly inconsistent with Ofgem's statutory duties.

There is time before Final Determinations to remedy these issues. We include evidence for each of these issues and more in our response. At the highest level, we urge Ofgem to undertake the following remedies which are supplemented by more detail in the body of this response:

Remedies required:

- Develop a more balanced appraisal of allowed equity return and remove the flawed outperformance wedge
- Undertake a financeability assessment which aligns to rating agency methodologies and factors in delays between spend and revenue under uncertainty mechanisms.
- Provide ex-ante allowances for uncertainty mechanisms and apply forecasting of outputs for allowances subject to reopeners.
- Adjust the risk/reward of the overall package to drive service improvements and reduce costs to the benefit of current and future consumers
    - Increase the upside potential from stakeholder supported ODIs including constraint management
    - Include risk trading in the Network Asset Risk Metric (NARM) regime and remove ex-ante clawback mechanism
    - Reassess the treatment of high and low confidence costs to increase the totex sharing factor
- Drop the disproportionate and unjustified Business Plan Incentive penalty and recognise ambitious activities and costs which add consumer value
- Address issues with efficiency methodologies and recognise the stretching efficiency ambition already applied to our plan.
- Reflect FTSE100 and utility sector benchmarks for dividend yield assumptions used in the financeability assessment

Summary narrative

Before we respond to the detailed questions of the Finance Document, we unpack the main issues with the proposed financial framework in this section. These issues focus on the introduction of: **inadequate returns**; **a marked weakening of financial resilience**; and **unachievable allowed equity return**.

We take each in turn, explaining where Ofgem is at risk of erring in its proposed framework, why this gives rise to consumer detriment and setting out the required remedies for the Final Determinations.

Inadequate equity returns

The past stability and predictability of the Weighted Average Cost of Capital (WACC)-setting process is the cornerstone of the UK regulatory model, where the focus has been squarely on achieving two highly desirable outcomes:

- maintaining investor confidence to keep investors' cost of capital of investing in the industry low; and
- stimulating significant dynamic efficiency improvements, in large part through a predictable approach to remuneration of assets and incentivising performance.

A stable regulatory regime has been the reassuring anchor for investors over the last thirty years and enabled sufficient financial capacity through the uncertainty of COVID-19, supporting financial security across the industry.

In contrast, Ofgem's DD represents a significant departure from this cornerstone including lower allowed equity return than required by comparable benchmarks in the UK and international capital market, downward skewed incentives and ex-post adjustments. At the same time, Ofgem is increasing framework risk by introducing greater uncertainty over the quantum, timing and recovery model for over 40% of the investment that is likely to be delivered during RIIO-2.

These changes substantially heighten regulatory risk and threaten to undermine investor confidence in UK regulation, increasing the cost of capital over the long term and slowing the pace of delivery of net zero infrastructure which is critical to the decarbonisation of the wider economy.

Ofgem has stated that the DD is:

"*keeping costs as low as possible for consumers by proposing the lowest ever rate of return on capital for network companies*"

on the basis that it is:

"*making room for around £25 billion of investment needed to drive a clean, green and resilient recovery.*"

The £25 billion quoted is across the Gas Distribution and Transmission sectors, however this figure could well be much larger given customer drivers for our Electricity and Gas Transmission businesses could mean the combined overall investment across just these two companies could reach over £15bn in the period. Delivery of this investment by large regulated network companies like ours, is a low-cost option, but only if regulatory stability and investor confidence is maintained.

The attempt to justify an inadequate allowed equity return ignores that the investment required to deliver net zero is complex, requiring networks to innovate to manage significant construction risk and find optimal solutions to complicated and often cross industry problems. Such a significant reduction in cost of equity at the same time as an increase in risk will be seen through by the investment community.

The competition for capital is global and the energy sector is not immune to economic drivers. The return on capital cannot be set in isolation of comparable market benchmarks, without eroding investor confidence and triggering delays to critical network infrastructure which will require higher spend in the future to 'catch up'. Investors will expect management to allocate capital efficiently, which is reflected in commentary from the sell-side analysts, for example

"*We also think the US offers higher growth and better returns in comparison to the UK, so we would not be surprised to see National Grid moving its investment / funding focus even more into the US*"[1].

The message from Ofgem is that companies should do as little as possible, not lead from the front on net zero. Whilst the message to investors from the DD is to move their capital overseas or into the water sector where returns are much higher

We address errors which lead to inadequate returns further in our response to FQ5 to FQ11 with the main errors set out below under four key areas:

- Ofgem's reliance on an unjustified presumption that the energy and water sector have the same risk leads them to understate the cost of equity
- Ofgem's cross checks are not relevant when setting the cost of equity for the UK's energy networks
- Total market return is incorrectly reduced but is subject to current CMA appeals
- The conceptually and practically flawed outperformance wedge will lead to increased costs for consumers

Ofgem's reliance on an unjustified presumption that the energy and water sector have the same risk leads them to understate the cost of equity

Ofgem proposes a reduction in equity beta which would impact overall allowed equity return by over 100bps compared to RIIO-1, with no support for such a reduction from market evidence on betas for the energy sector. Indeed, National Grid plc's beta has increased over the last six years. Furthermore, there are indications risks have increased given the scale and complexity of net zero investments, the very low baseline totex allowances and uncertainty over when revenue will be recovered.

Ofgem's key argument in this area is their view that energy network risk is the same as water, a departure from RIIO-1 where there was a differential of over 100bps in allowed equity return to water and inconsistent with recent sell-side commentary:

"We believe power and gas networks have a higher structural beta than water"[2].

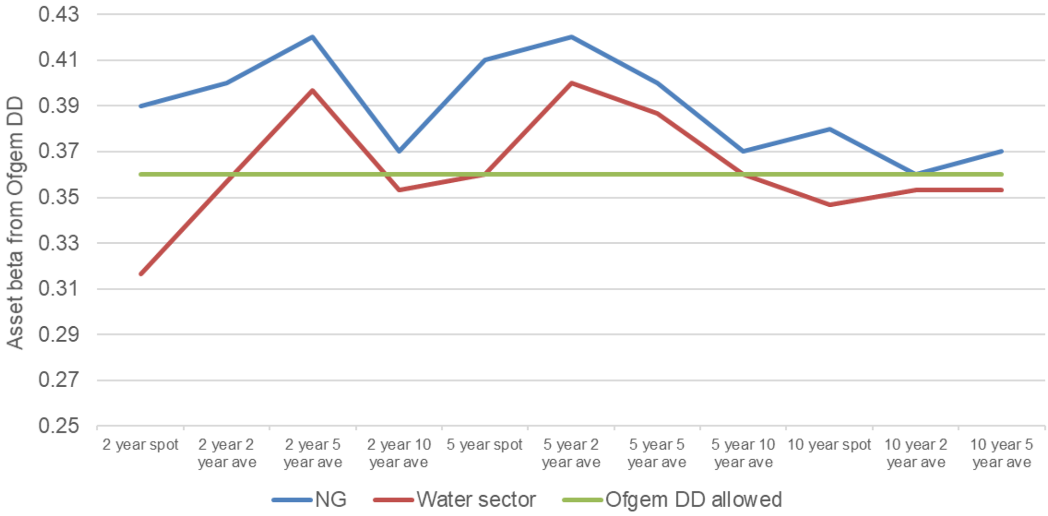
Ofgem relies on a qualitative analysis performed by their consultants CEPA. However, within CEPA's own report they acknowledge that there are reasons why energy has higher systematic risk than water[3]. CEPA also state that energy has higher dynamic risk than water due to the energy transition[4] yet Ofgem does not account for this either in beta or in other elements of the price control.

CEPA's work and Ofgem's proposals represent a subjective judgment based on the weighting that is applied to each of the qualitative factors reviewed. More importantly though, Ofgem has ignored direct market evidence that can and should be used in setting energy network betas.

[1] "(Tougher) life under RIIO-2 (part 3), but fundamentally undervalued" Societe Generale, 16 July 2020
[2] "It can only get better" Barclays, 13 August 2020
[3] "RIIO-2: Beta estimation issues" CEPA, 9 July 2020, Page 5
[4] "RIIO-2: Beta estimation issues" CEPA, 9 July 2020, Page 38

Ofgem's own data in the DD shows that the National Grid (NG) plc's asset beta has been 5 to 12% higher than water using all estimation techniques and averaging periods for all the time periods analysed in the DD. Simply taking a proper account of this alone would add at least 60bps to the allowed equity return.

Figure 1: asset beta from DD over multiple time and averaging periods



In addition, we can disaggregate NG plc's asset beta into a GB, US and much smaller non-regulated component. Using betas for US peers which are far lower than UK counterparts shows that under any reasonable configuration of assumptions the estimate for NG's GB asset beta would be higher than that of NG plc. NG's group beta can therefore be interpreted as a clear lower bound for the beta of UK energy networks and provides direct market evidence that Ofgem's point estimate cannot be supported and is too low.

Ofgem's cross checks are not relevant when setting the cost of equity for the UK's energy networks

Ofgem compound issues with aligning energy betas to water by relying on Market to Asset Ratio (MAR) data (essentially the premium or discount to RAV) for the two listed water companies in further reducing their return by 10bps.

MAR data is inherently transient and unreliable to use for forecasting a return for a future five-year period. Assessment of the water company MARs shows that within each 5-year price control period the MAR fluctuates significantly – from 30% at its peak to below 5% in the 2005 to 2010 price control period. By using this data, Ofgem are adding a new source of volatility into return determinations, owing to inherent volatility of stock prices and the small number of listed comparators, most of which are not even energy networks.

The CMA and its predecessor the Competition Commission (CC) have recognised the significant uncertainties in interpreting MARs when considering the data in previous regulatory appeals. These include the existence of a wide range of views in the market over valuations, numerous factors that feed into an investor's decision to buy shares and inherent inconsistencies between the numerator and denominator of the calculation relating to time periods used.

Notwithstanding the points on why MAR data should not be relied upon to set RIIO-2 returns, Ofgem's analysis of water company MAR figures does not fully take into account the impact of incentive opportunity, debt performance and control premia. Oxera's analysis of analyst reports[5] shows that the premiums can be explained by factors not related to cost of equity and indeed there is if anything proof that the allowed equity return for PR19 is too low.

Ofgem also reference Offshore Transmission Owner (OFTO) returns, infrastructure funds and investment fund forecasts in their cross checks of the return. Neither of these is directly comparable to energy networks:

- OFTO returns are actually higher than those proposed in the DD but relate to operating assets which have already been built so do not have any construction risk;
- Infrastructure funds incorporate multiple investments so are diversified by design so the risk profiles are lower than UK energy networks
- Investment forecasts are from pension investment advisors whose regulatory rules require them to be conservative so will forecast only low-end views of equity return. The forecasts referenced by Ofgem are also out of date, all coming from pre-December 2019; before the more recent economic turmoil.

Total market return is incorrectly reduced but is subject to current CMA appeals

Ofgem estimates the Total Market Return (TMR) portion of allowed equity return using a back-cast of Consumer Price Index (CPI) inflation which the authors of the data set and the Office for National Statistics (ONS) consider to be unreliable. Within the estimation, Ofgem has relied on historical TMR data sources which are artificially reduced and also fail to recognise the negative impact on investment decisions from not using a figure at least as high as the historical arithmetic average. As a result, Ofgem's proposed figure is over 100bps below the regulatory precedent on a like for like basis and in effect undermines the value neutrality of the transition from Retail Price Index (RPI) to Consumer Prices Index including owner occupiers' housing costs (CPIH) indexation.

Ofgem's range and point estimate are broadly in line with those of Ofwat in the PR19 price control Final Determinations. The material errors outlined above are currently being appealed to the Competition and Markets Authority (CMA) by four water companies and we have submitted supporting evidence as part of the Energy Networks Association (ENA) third party response. There are other elements of the RIIO-2 financial framework that are also in scope of the CMA appeal such as the approach to measuring the Risk-Free Rate (RFR), the long-standing principle of aiming up within the cost of equity range in order to minimise potential social welfare impacts and the approach to setting debt beta. If the CMA findings were to agree with the water companies in any of these areas, then it would have an upwards impact on Ofgem's proposals in the DD.

The conceptually and practically flawed outperformance wedge will lead to increased costs for consumers

After applying downward adjustments to the cost of equity as a result of their cross checks Ofgem proposes a further downward adjustment to cost of equity of 25bps in anticipation of outperformance. This adjustment is conceptually and practically flawed.

From a conceptual perspective, the adjustment suggests a lack of confidence in proper calibration of the price control even before it has been attempted. This cannot be the case. Ofgem has adequate tools and data to be able to achieve this. The approach does not recognise and appreciate the consumer benefit of incentives-based regulation, the widely-accepted solution to the existence of monopoly. It further exacerbates the downward skewed incentive package as networks need to first 'earn back' the outperformance wedge.

[5] Oxera, 'What explains the equity market valuations of listed water companies?' 20 May 2020

In applying its adjustment to the WACC, which is then applied to the Regulatory Asset Value (RAV), Ofgem is in effect retrospectively clawing back the value of past investments. This runs counter to established regulatory practice in the UK and will unquestionably undermine investor perceptions of risk. It will also undermine the incentive properties of RIIO-2 as companies will enter a price control period with the knowledge that any incremental outperformance achieved will lead to a worsening of future price controls calibrations.

We note that Ofgem has not performed an assessment of the potential damage that can be caused by the proposed outperformance adjustment to baseline returns, which is particularly worrying given Ofgem is the only regulator to implement this untried and untested new mechanism. Work by Frontier Economics[6] shows several likely consumer detriments to the adjustment including a reduction in future productivity and future service delivery. Frontier show that even a 4% reduction in network productivity would offset the consumer bill “upside” from lower return.

From a practical perspective there is little evidence to support Ofgem’s calibration of the wedge. RIIO-2 is fundamentally a different price control to RIIO-1, it is therefore not reasonable to look at the performance in RIIO-1 or prior price control periods to predict RIIO-2 performance.

Ofgem set out a database of historical price control performance as part of the DD which suggests on average price control totex allowances are outperformed by 7%. Frontier have reviewed this on behalf of the ENA and find it to contain multiple errors so it cannot be relied upon. Frontier’s found a spreadsheet error which overstates the outperformance in RIIO-GT1 and other issues with the interpretation of water price controls and historical data points.

Further, Frontier note that half of the assumed outperformance relates to the supernormal efficiencies delivered by the first distribution price controls post privatisation. These were set up on a completely different basis to any current price control and have no relation to RIIO-2. The related results therefore need to be excluded. Similarly, airport and other CAA regulated price controls need to be excluded because they are not set in the same way as energy price controls.

Having made these adjustments, Frontier then account for the numerous differences between RIIO-1 and RIIO-2 which had not been captured by Ofgem’s original analysis. These include the differences between the Information Quality Incentive (IQI) and BPI incentives and the tougher productivity assumption and benchmarking in RIIO-2 compared to RIIO-1. They were not able to adjust for Price Control Deliverables (PCDs), NARMs and the impact of fast tracking in RIIO1 but assess qualitatively that these would have a material downwards impact on the expected return for RIIO-2. Their conclusion was that the database does not support an expected outperformance of historical price controls. Indeed, for RIIO-2 they have separately used Monte Carlo analysis to assess that the expected return is zero performance, with qualitative reasons why this could be negative.

In response to criticism of the outperformance wedge, Ofgem has introduced a backstop mechanism that will increase returns if the average performance across two groups, the electricity transmission companies and gas companies, is below the expected return. Aside from implying a lack of confidence in Ofgem’s own implementation of the backstop, the use risks distorting incentive properties where the group performance is below the expected return. It also assumes that calibration of totex allowances and ODIs are consistent between the Gas Transmission and Gas Distribution sectors which is not the case given the markedly different Return on Regulatory Equity (RoRE) ranges.

[6] “Further comment on Ofgem’s proposal to adjust baseline allowed returns”, Frontier, August 2020

Remedy required:

- Develop a more balanced appraisal of allowed equity return and remove the flawed outperformance wedge

A marked weakening of financial resilience

The overall price control framework must, at its most fundamental level, demonstrably fulfil Ofgem's statutory duty to ensure networks are able to finance licensed activities whilst having regard to the interests of both current and future consumers. It is in the consumers' interest that we finance our licensed activities as efficiently as possible. This is best achieved by maintaining a strong credit rating and providing confidence to investors that their investment is secure. Ofgem's proposals provide neither. Even the way in which financeability has been assessed raises several concerns:

- The financeability ratios Ofgem presents within the RIIO-2 Draft Determinations – Finance Annex are misleading and cannot be relied upon
- The methodologies underpinning the financeability ratio calculations are inconsistent with those employed by ratings agencies.
- The financeability assessment does not adequately stress test whether the RIIO-2 framework can support net zero investment levels
- Insufficient weight is given to equity financeability resulting in a risk / return imbalance
- Ofgem fails to identify or assess the financeability impact of the cashflow risk arising due to the time delay between spend and revenue recovery

We address these points further below and in our response to questions FQ12 and FQ13

The financeability ratios Ofgem presents within the RIIO-2 Draft Determinations – Finance Annex are misleading and cannot be relied upon

To accurately assess the full RIIO-2 package proposed by Ofgem, the individual inputs of the financeability assessment are required to correspond with those proposed through the Draft Determinations documentation. However, this is not the case with Ofgem's Licence Model (LiMo).

The baseline totex scenario used within Ofgem's GT2 LiMo is inconsistent with those proposed in the NGGT document. The baseline funding used by Ofgem is £450m higher[7] in the LiMo than the £1.5bn figure which appears in the NGGT document. This gives rise to artificially higher credit metrics.

Therefore, the financial ratios quoted within the Finance Annex cannot be used as a reliable starting point on which to assess the cashflows, the financeability and the consumer impact of Ofgem's proposed package.

[7] Before Real Price Effects

The methodologies underpinning the financeability ratio calculations are inconsistent with those employed by ratings agencies.

Ofgem base their financeability assessment on revenues which include assumed earned income performance of 25bps per annum (linked to the outperformance wedge) and exclude the BPI penalty which reduced revenues by the equivalent of 18bps per annum[8] This equates to a cashflow uplift of £54m, resulting in Ofgem's approach understating the financeability challenge implied by the Draft Determinations.

The notional company should be financeable without the need to rely on assumed outperformance, a principle that is even more important in the context of a price control in which outperformance is highly unlikely. This aligns with credit rating agencies' methodologies under which outperformance will only be taken into account once a network demonstrates a track record under a given price control framework. It is also clear that a notional Transmission company would receive a BPI penalty under the current formulation as it does not take into account the inherent difficulties in benchmarking transmission costs[9]. The impact of the BPI penalty must therefore be included in the financeability assessment.

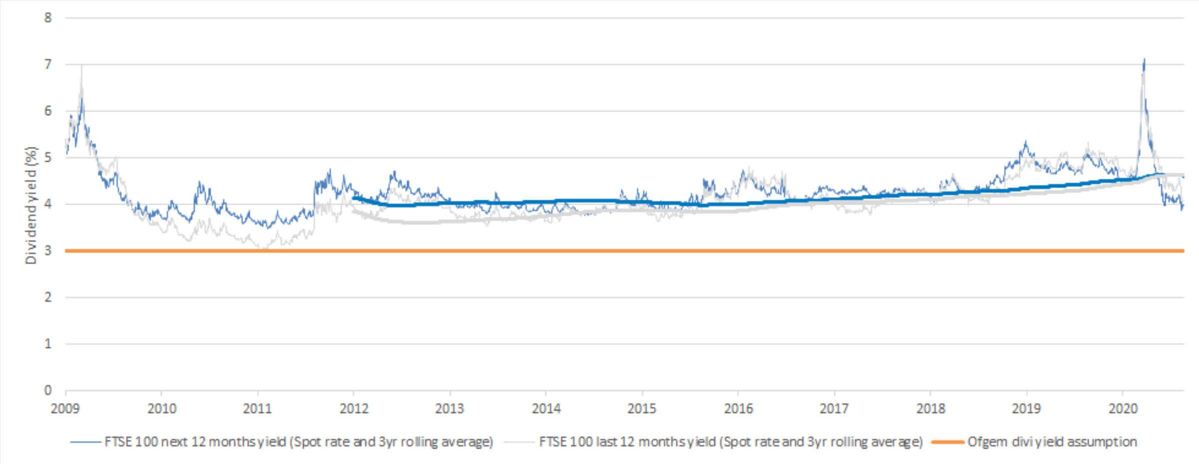
Insufficient weight is given to equity financeability resulting in a risk / return imbalance

The equity risk and return implied by the DD is out of balance. Under Ofgem's package equity investors will bear additional risk for totex uncertainty and downward skewed set of allowances and incentives plus an appreciable increase in regulatory risk, in exchange for returns which are lower than ever.

As Ofgem states, equity investors are remunerated through current dividend yield and future growth in assets. Neither Ofgem's baseline nor Illustrative UM scenarios deliver a combined dividend and growth prospect for equity investors which reflects this risk. With notional dividends of 3%, which are substantially lower than average FTSE100 outturns of at least 4%, and a baseline RAV reduction of 1.4% in real terms, Ofgem has been complacent in its approach to financeability by failing to give due consideration to the needs of equity investors. Ofgem's assessment focuses on the debt investor and fails to recognise that if the investment proposition is not sufficiently attractive, shareholders will choose to reallocate capital elsewhere or to regulated utilities in other jurisdictions, resulting in an increase in cost to raise necessary finance, both in RIIO-2 and subsequent periods. In a period where more activity than ever may depend on networks bringing forward projects for funding through UMs, the risk of companies dragging their heels over valuable but ultimately discretionary investment has never been so high. Ultimately it is consumers who would suffer because the overall attractiveness of the regime is insufficient to encourage companies to want to sink more capital than is necessary.

[8] Ofgem analysis, Draft Determinations – Finance Annex, Table 45
[9] See NGGT response for more detail on our view on the BPI

Figure 2: Historic FTSE 100 dividend yields

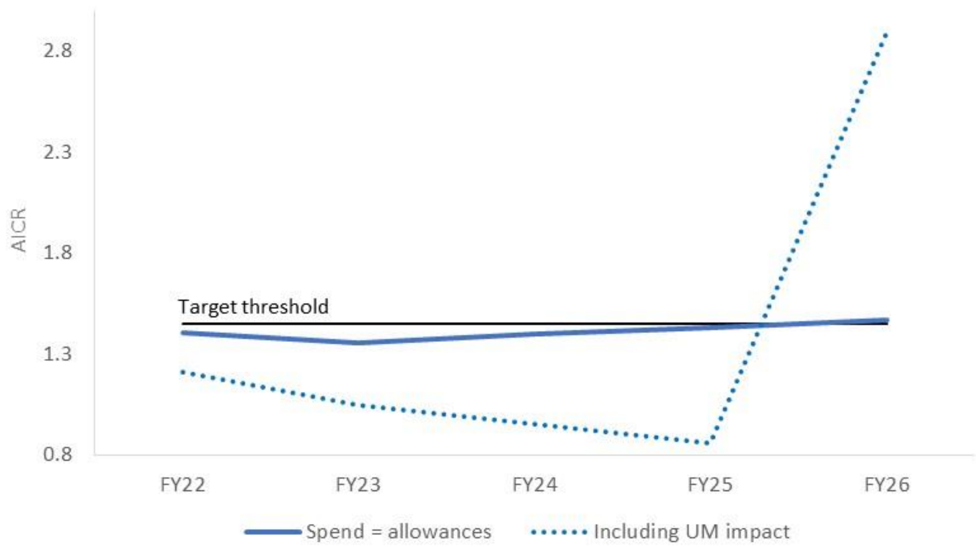


Ofgem fails to identify or assess the financeability impact of the cashflow risk arising due to the time delay between spend and revenue recovery

Ofgem's financeability assessment is based on the premise that allowances are triggered when investments are made. This is not the case for funding delivered through uncertainty mechanisms where there is a delay in allowance recognition until an output is delivered or Ofgem issue a determination. With over 40% of potential totex in scope of UMs, failure to recognise this time delay excludes a significant cash flow risk from the financeability assessment. We are being forced to take a substantial funding and cashflow risk which will not be compensated for by the inadequate returns.

The framework as proposed would require hundreds of millions of pounds to be spent ahead of secured funding but with inadequate allowances and returns there is no financial capacity for networks to absorb this cashflow risk. Ofgem's financial package must allow sufficient headroom for networks to be able to invest proactively and operate in an increasingly complex and uncertain environment.

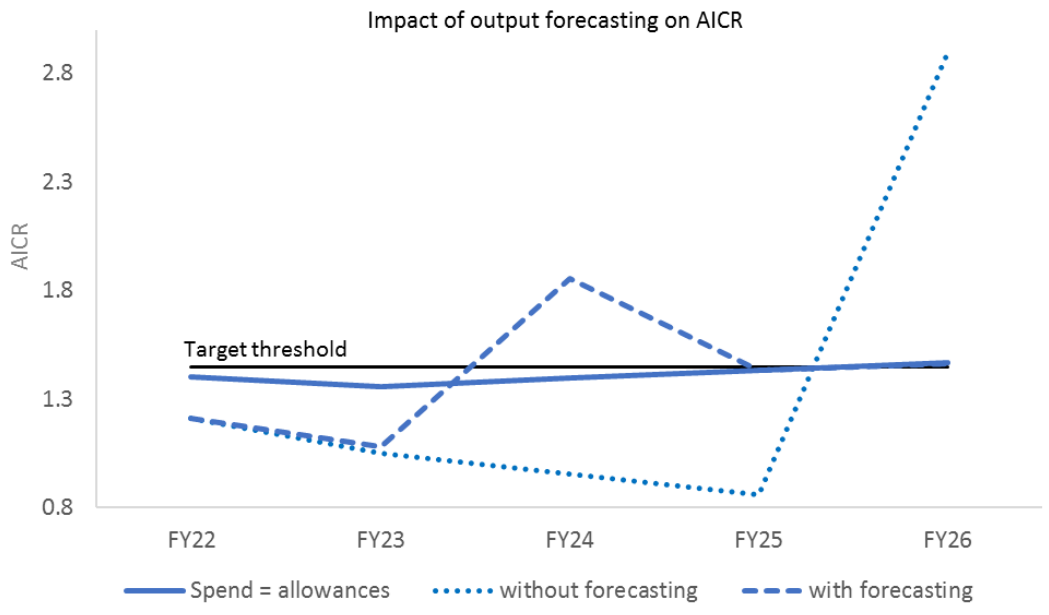
Figure 3: AICR trend including gap between spend and revenue under uncertainty mechanisms



There are framework remedies that would help with the position

There are remedies that could help this position. Ofgem has introduced the concept of forecasting of outputs in RIIO-2 which will enable revenue to more closely reflect the underlying costs than it did in RIIO-1. We are advocates of this approach as it improves transparency and predictability of customers' costs and our revenue. However, Ofgem has discounted this approach for reopener uncertainty mechanisms which effectively excludes this method for Gas Transmission. This needs to be reversed in order to improve financeability and enable our revenue to more accurately reflect the underlying costs. Reporting at the end of RIIO-1 also needs to be updated so that forecasting can begin from the start of the period. The potential benefit from applying forecasting to reopeners can be seen in Figure 4 below.

Figure 4: AICR trend factoring in potential benefit of forecasting for reopeners



In addition, Ofgem have moved multiple investments out of baseline funding and into the scope of in period reopeners. For many of the reopener uncertainty mechanisms, the need for a level of expenditure has been established by Ofgem. Uncertainty only exists in the precise scope or cost of activities. In these circumstances, the cashflow risk can be reduced by aligning our baseline allowances with likely spend and adjusting from that position in the period.

We proposed this as part of our business plan, and it would have the added benefit of making customer charges more stable in the period, smoothing out a potential 40% increase in charges in the last year. We recognise that placing the entire £1.2bn of potential investment in the baseline could create variability in charges if the investment was found not to be required in the period. However, a sizeable proportion, potentially half of this value, would provide a more balanced approach to setting customer charges in the period.

These solutions would not address all the issues, but they would close a substantial proportion of the cashflow gap. The remainder would be closed by taking a more balanced assessment of the allowed equity return evidence. Ofgem may assess that the notional gearing could be reduced given the credit metric shortfall, as with the Electricity Transmission sector. As the notional gearing has already dropped from 62.5% in RIIO-1 to 60%, there is limited scope for this and we would not supportive of material movement, however if the equity return and broader policies had been tested robustly (which in our view they have not yet around equity return at least) a small change could be justified to improve short-term credit metrics.

Additionally, from an equity perspective, Ofgem need to reflect the higher dividend yields based on FTSE100 and utility sector benchmarks in the financeability assessment and ensure that the allowed equity return is achievable. In the next section, we set out evidence why this is not the case for the DD.

Remedy required:

- Undertake a financeability assessment which factors in delays between spend and revenue under uncertainty mechanisms.
- Provide additional ex-ante allowances for uncertainty mechanism expenditure and apply forecast of outputs for allowances subject to reopeners.
- Reflect FTSE100 and utility sector benchmarks for dividend yield assumptions used in the financeability assessment

Unachievable allowed equity return

Although Ofgem set out their expectation of the potential RoRE that networks can achieve in the DD, they do not ask any consultation questions on this analysis. The potential and expected RoRE is an important topic and a key point of comparison across regulatory sectors. We have therefore outlined our views on Ofgem's quoted ranges and the overall price control package below. Taken as a whole, we see that the downside skew across multiple aspects of the DD calibration gives rise to an unachievable allowed equity return which risks undermining a fundamental requirement of a fair deal price control.

Ofgem state that the RIIO-2 package represents a reasonable balance between scope for outperformance for high performing companies and underperformance for those companies that fall short. In reality, the RIIO-2 package is skewed towards underperformance with an undue focus on short term bill reduction. The DD takes a fundamentally different direction to the RIIO-1 framework, removing incentives and opportunities to deliver innovations for consumer benefit and moving away from an outputs-based regulatory structure to one of more regulator micro-management.

Ofgem have set a steep challenge for transmission networks – and National Grid in particular - if they are to even reach base returns and have almost completely turned off performance from output and cost incentives that have benefited consumers in the past and which our stakeholders continue to support going forward. In all, RIIO-2 is not a price control where investors can realistically expect to achieve the allowed equity return.

Transmission companies in particular start the price control facing a stark shortfall to allowed equity return

Ofgem's view of RIIO-2 RoRE ranges misses essential facts, namely that the layering of adjustments and penalties through the price control review mean that NGGT start the RIIO-2 price control with a significant shortfall to offset in order to achieve the allowed equity return. Without any savings, we would report a RIIO-2 RoRE of 2.7%, some 150bps below expected return, due to the inclusion of the following in Ofgem's framework:

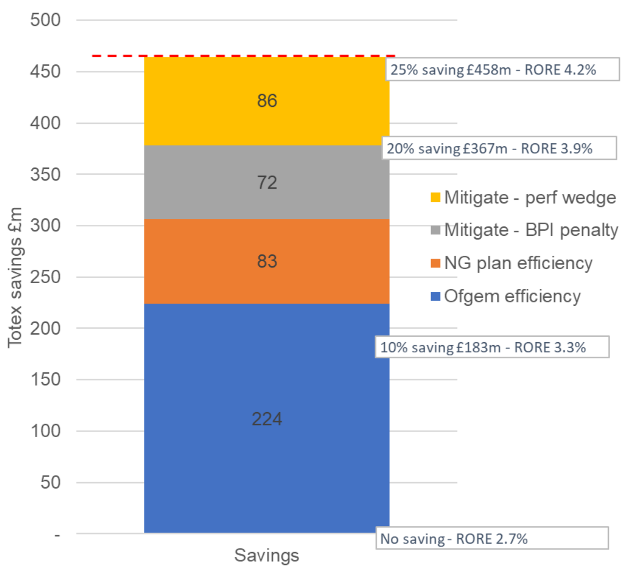
- **Outperformance wedge** – We have set out our disagreement to the principle of the outperformance wedge as an unnecessary intervention, the perverse incentive for performance and also the judgmental selection of the 25bps adjustment in the Inadequate equity returns section above and in response to FQ9. Given the significant changes to the RIIO-2 framework, 25bps performance is highly unlikely to materialise with the upshot that expected returns will be below allowed return. Even if the ex-post adjustment to the wedge was to apply, this would still leave us below the allowed return throughout the whole of the RIIO-2 period. We would need £86m of totex savings across the period to offset the gap created.

- **BPI** - The principle of incentivising networks to properly engage with the price control review process is long established, however the RIIO-2 BPI is a poorly calibrated mechanism that has resulted in unjustified and disproportionate penalties that dwarf networks' potential performance over the RIIO-2 period. We set out evidence for why this is unjustified in the NGGT document. The resulting RoRE impact of 23bps must be taken into account when assessing potential RoRE performance. This gap is the equivalent of £72m totex savings across the period.
- **Unprecedented efficiencies** – Ofgem's draft determination has resulted in totex disallowances that are world apart from previous regulatory decisions, with a total of £4.8bn of costs disallowed equating to a reduction of 48% across Transmission. NGGT starts RIIO-2 with allowances of around three quarters of its RIIO-1 spend to run and maintain the transmission network. A large part of this reduction is an unprecedented and unjustified 12% cost efficiency against the allowed volume. We set out the evidence for why this level of efficiency is unjustified in response to the NGGT document. This is the equivalent of £224m totex savings across the period. If we were to deliver no savings from our current operations this would result in a 71bps underperformance.

We had already embedded totex efficiencies of £83m into our plan, including the highest productivity assumption across all networks and the savings from our ambitious end of RIIO-1 period restructure. These have not been fully delivered yet and add 26bps to the challenge from our current cost base.

The downside risk before RIIO-2 even starts is represented by the graph below which shows that to close the gap to allowed return we would have to deliver the volume of work allowed in the DD for 25% less than our current operations. Given the nature of the RIIO-2 framework, this position could be worse. Of the £1.6bn baseline totex allowances included in the DD, we are only incentivised on £1.1bn. The remaining 31% is subject to true up and claw back meaning we would not receive any benefit from innovations to reduce cost. When this is factored in, we would have to deliver 43% of totex savings from our current operations to achieve the allowed equity return.

Figure 5: Starting RoRE and totex savings gap to deliver allowed equity return



The upside from incentives would not allow us to close the gap

On top of the higher than ever challenge from day one of the price control, Ofgem has dampened incentivisation in RIIO-2 which gives no chance of reaching allowed equity return in the period. Ofgem has weakened or switched off a range of incentives, sending the signal that it does not value stronger performance in these areas, but also removing any opportunities for good performing networks to differentiate themselves and secure additional rewards for driving improvements for consumers through RIIO-2 and into future price controls. Consumers will directly suffer as a result, but there will be further effects as it becomes clear that there is no prospect of achieving even the baseline level of return.

- **ODIs:** Ofgem state that their expectation, based on actual performance to date, is that the three TOs should perform well on ODIs and the more extreme downsides are unlikely to materialise. However actual performance to date is a poor reference point for future performance given the fourfold reduction in ODI value, and toughened targets baked into the incentives. We set out our views on the ODIs and the evidence for increasing the caps on stakeholder agreed incentives such as constraint management in the NGGT document. Frontier Economics[10] have undertaken detailed Monte Carlo analysis on the expected ODI outcome which shows 3bps upside performance from the ODI package proposed. This is not enough to offset the outperformance wedge assumption let alone the rest of the RoRE shortfall at the start of RIIO-2.
- **Totex performance:** Ofgem have assumed a 10% under or outperformance in their RoRE analysis, on which they do not provide any further elaboration. It is clear that the DD is nothing like the RIIO-1 framework so the likelihood of and incentives for achieving even close to 10% totex performance are markedly lower. The DD moves away from an outputs framework that enabled a significant proportion of the RIIO-1 outperformance into one including numerous ex-post mechanisms to remove performance, lower totex sharing factors and micro management of delivery. Frontier again use detailed Monte Carlo analysis to outline an expected totex performance of zero percent and give qualitative reasons why this figure may be lower. In doing so, Frontier correct Ofgem's assumption of 7% historic totex performance used in justifying the outperformance wedge. Frontier remove the impact of super-normal efficiencies from early ED and GD price controls that were set on a markedly different basis. This halves the 7% figure. Frontier then give qualitative consideration to the below which reduces the expected performance to zero:
    - The introduction of indexation of RPEs in RIIO-2, more closely aligning network cost base with input price movements and removing windfall gains or losses that are outside of network controls. Whilst difficult to quantify over multiple price controls, Frontier note that movements in RPE indices equate to around half of the total outperformance Ofgem forecast for NGGT in RIIO-1.
    - The increase in Price Control Deliverable (PCD) and NARM mechanisms covering 60% of the baseline totex allowances in RIIO-2. These mechanisms incorporate ex post adjustments and judgements which increase the likelihood of downside risk and only permit limited upside outperformance.
    - An undefined RIIO-2 close out process that could potentially reopen the whole price control.
    - Systematic skew in calibration of sharing factor calculations which penalises transmission networks for the lack of econometric benchmarking approaches and which is acknowledged by Ofgem but not remedied. This reduces the pay back of any innovation should it be judged by Ofgem to be a "genuine efficiency" in ex post review.

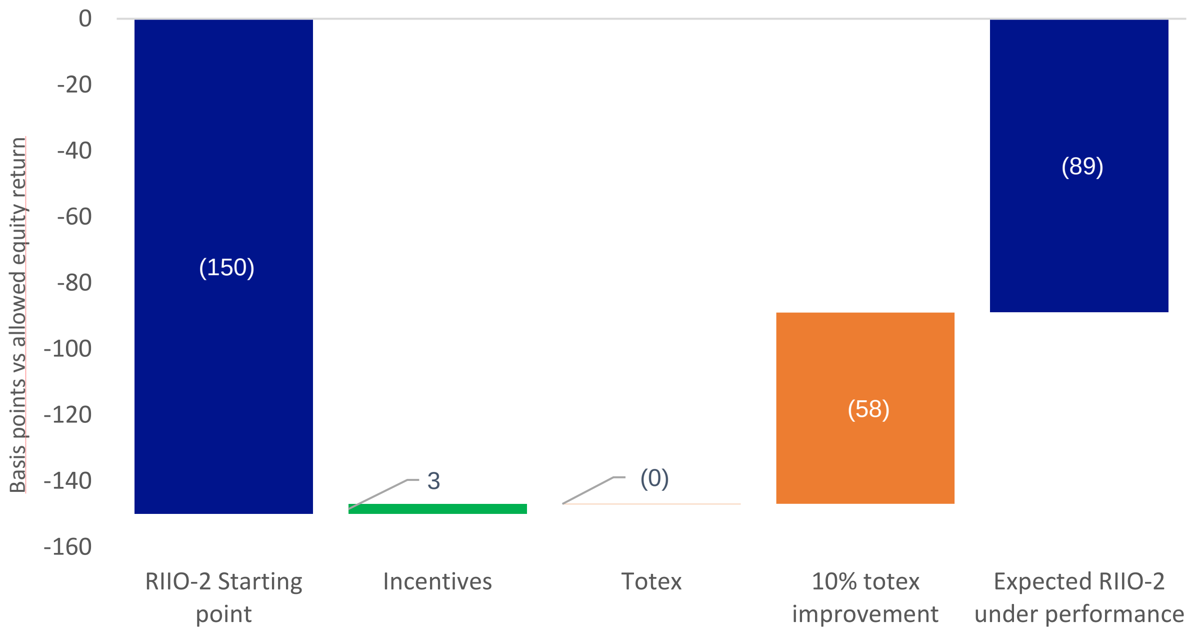
All of this points to minimal variance around the low starting point through the five years of RIIO-2. At best, we could deliver a small level of performance that would hardly register against the expected return we begin the period with.

[10] National Grid Wedge update, September 2020

Investors cannot expect to earn the allowed equity return

In short, this analysis shows that investors cannot expect to earn a return in line with the cost of capital under RIIO-2. The waterfall below sets out the potential movements from the DD starting point, highlighting a significant remaining gap. Within this analysis, we have also included the impact a potential 10% improvement in totex performance would have on the figures. This adjustment reflects that in previous price controls, where the opportunity and incentive to perform has been higher, there have been elements of efficiency challenge placed on networks. These have averaged under 10% rather than the higher figures proposed by Ofgem in the DD. We have therefore included 10% in this analysis to show that the unachievable allowed equity return remains even if Ofgem reduce the efficiency gap by the time of FD or we were somehow able to deliver – and retain the benefit of following any ex-post true up - a greater level of efficiencies than those embedded in our business plan.

Figure 6: waterfall from RIIO-2 RoRE starting point



The table below sets out the expected movements from base return in more detail.

Table 1 Movements from base return

NGGT	Pre-RIIO-2 performance					RIIO-2 performance		
	Base return	**Wedge**	**BPI penalty**	**Efficiency cut**	**Pre-performance return**	**ODI**	**TIM**	**Total return**
Ofgem max	4.2%	-0.25%	-	-	3.95%	0.24%	0.50%	4.69%
Ofgem min	4.2%	-0.25%	-0.23%	-	3.72%	-1.14%	-0.50%	2.08%
Expected	4.2%	-0.25%	-0.23%	-0.98%	2.74%	0.07%	0.00%	2.81%

Aside from the significant shortfall created, this type of regulatory framework will:

- **Undermine regulatory stability:** An ability to achieve the allowed equity return is one of the fundamental tenets of regulation and the stability around the regime that investors take comfort in. Without this, consumer cost will increase as investors will need a higher return to offset the risk of not recovering a fair return.

- **Bring into question Ofgem satisfying their Financing Duty:** The ability to deliver allowed equity return is so fundamental that the DD content questions whether Ofgem can deliver their Financing Duty. Currently, investors would not get their money back from their investments as the return could not be achieved.

Remedy required:

- Drop the disproportionate and unjustified Business Plan Incentive penalty and recognise ambitious activities and costs which add consumer value
- Address issues with efficiency methodologies and recognise the stretching efficiency ambition already applied to our plan.
- Remove the flawed outperformance wedge
- Adjust the risk/reward of the overall package to drive service improvements and reduce costs to the benefit of current and future consumers
    - Increase the upside potential from stakeholder supported ODIs including constraint management
    - Include risk trading in the NARMS regime and remove ex-ante clawback mechanism
    - Reassess the treatment of high and low confidence costs to increase the totex sharing factor

Context

We respond to the questions in the DD consultation in the order they appear in the document which means they are contained in four different sections in this document:

- Allowed debt return
- Allowed equity return
- Financeability
- Other finance issues

As well as answering the questions posed by Ofgem, we also offer additional evidence and narrative at the start of each of these sections to contextualise the responses and supplement information where no direct question has been posed on an important subject.

We have submitted evidence, including consultants' reports, as part of previous consultation responses and in support of our business plan submission. There are a significant number of areas where Ofgem has not properly addressed the arguments and evidence we have submitted, such as in response to National Grid's Total Market Return report[11], a lack of adequate justification for Ofgem's proposal to exclude DNO cost of debt from the trailing average cost of debt calibration and in relation to Ofgem's proposed Step 3 'Expected versus allowed returns' deduction.

In order to be concise we have not repeated many of these arguments in detail and neither have we resubmitted our previous evidence, but they should nevertheless be considered part of our response to the DD and Ofgem should consider these reports, including the evidence and reasoning set out in them, further and address them in its Final Determination.[12]

[11] See National Grid's report "Total Market Return", 23 January 2020, https://www.nationalgrid.com/uk/electricity-transmission/document/132971/download, which presented evidence that RPI was a more consistent measure of inflation to use when deflating historic nominal returns information to estimate TMR, as well as identifying two other sources of downwards bias in Ofgem's estimation of TMR

[12] We refer Ofgem to the material which National Grid and the ENA have submitted in response Ofgem's March 2018 "RIIO-2 Framework Consultation" and in response to Ofgem's December 2018 RIIO-2 Sector Specific Methodology consultation; in National Grid's business plan submissions to Ofgem in July, October and December 2019; the additional documents available in the finance section of National's Grid's RIIO-2 business plan webpage (https://www.nationalgrid.com/uk/electricity-transmission/planning-together-riio/our-riio-2-business-plan-2021-2026/finance); the ENA's submissions to the CMA in relation to the price control appeals by NATS and by 4 water companies during 2019 and 2020 (https://www.gov.uk/cma-cases/nats-en-route-limited-nerl-price-determination and https://www.gov.uk/cma-cases/ofwat-price-determinations) together with the additional documents related to these ENA submissions which have been shared with Ofgem; and presentations and supporting material made by National Grid, the ENA, or consultants supporting National Grid or the ENA in meetings with Ofgem through the course of the RIIO-2 process.

Allowed return on debt questions

Full indexation of allowed return on debt should represent efficient notional company costs. All energy networks operate within the same industry, achieve similar credit ratings and invest in similar assets with comparable asset lives. The most appropriate approach is therefore an industry wide tracker with consistent tenor and rating of the index. As we stated in our business plan and Sector Specific consultation response, a trailing average length of 20 years is consistent with the long-term nature of the assets and is typical of the tenor of debt across the industry. In that sense, it is internally consistent with the iBoxx 10+ index which has been used in RIIO-1, the constituent bonds of which have an average tenor of c.20 years.

Ofgem has said[13] that the cost of debt indexation to be used in RIIO-2, specifically the length of trailing average, will be calibrated to ensure it provides a good estimate of efficient sector debt costs. However, Ofgem's DD does not appropriately estimate efficient sector debt costs as they exclude:

- £81m impact of debt buy back costs in the RIIO-1 period and do not calibrate debt costs against a broader industry-wide average which includes the electricity distribution networks. In so doing the tracker length is understated by 2 years; and
- at least 20bps of additional borrowing costs, largely due to the exclusion of the incremental costs of inflation linked debt, which are not captured in the nominal rate tracker mechanism that Ofgem proposes.

We advocate setting an industry-wide debt funding approach, as we outlined in our business plan. However, pragmatically we recognise Ofgem may be unlikely to want to set Electricity Distribution debt funding now. Ofgem can, however, still include this debt in the calibration for Transmission and Gas Distribution. The above changes would justify a 12 to 16 year trombone instead of 10 to 14 years for RIIO-T2 and RIIO-GD2, and since these trailing averages do not include the full costs incurred by networks, additional borrowing costs as proposed by Ofgem should be increased by at least 20bps to a values of at least 40bps.

We set out further detail in our responses to FQ1 to FQ3.

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

Allowed debt funding should be set to reflect the cost of debt that would be expected for an efficient, notionally geared network company that follows a typical, prudent and efficient debt financing strategy. Such a strategy would involve the notional network borrowing gradually over time, issuing long-term bonds periodically to support investment in long-term assets. Thus, in any given year, its balance sheet will contain debt issued over many previous years, in addition to the new debt it might issue to finance that year's activities and re-finance past debt that is maturing. For such a notional company, the best approximation for the efficient cost of debt is likely to be a trailing average of market index rates.

We support the policy objectives which have been set out by Ofgem for RIIO-2 and the direction of travel in establishing debt costs. This includes the treatment of intercompany loans and the approach Ofgem has taken to adjust for Cadent's low cost of debt (as a result of the company being newly formed) within the calibration process. However, there is additional evidence that we set out below to ensure that the framework fulfills Ofgem's policy objectives that:

- consumers should pay no more than an efficient cost of debt;
- the cost of debt allowance should be a fair and reasonable estimate of the actual cost of debt likely to be incurred by a notionally geared, efficient company;

[13] in Ofgem's "RIIO-2 Sector Specific Methodology Decision – Finance", 24 May 2019

- companies should be incentivised to obtain lowest cost financing without incurring undue risk; and
- the calculation of the allowance should be simple and transparent while providing adequate protection for consumers.

Currently, Ofgem's proposals fall short of ensuring the cost of debt allowance is a fair and reasonable estimate of the actual cost companies are likely to incur. Ofgem have overlooked an £81m impact from debt buybacks related to the sale of Cadent and historic debt buy back costs, and do not calibrate debt costs against an industry-wide average. In so doing Ofgem understate the tracker length by 2 years. We also have new evidence on additional borrowing costs that show Ofgem's allowance understates these costs by at least 20bps. This largely relates to the cost of inflation linked debt, which is not captured in the nominal rate tracker mechanism that Ofgem proposes.

Ofgem's proposals also risk consumers paying more than an efficient cost of debt in the future by using the iBoxx GBP Utilities 10yr+ index as Ofgem are transferring the cost of a network company's decision on their actual capital structure from the networks to consumers (see FQ2 for our detailed response on the index methodology).

Buyback costs

Past refinancing costs need to be taken into account, as otherwise consumers would benefit from the reduced interest rate achieved through re-financing without incurring any of the associated refinancing costs. Such an outcome would clearly be unjustified, and it could also have unintended effects, such as discouraging networks from some future decisions which might have reduced financing costs. Examples of such decisions might include reducing excess debt (and hence unnecessary interest costs as per the example of Cadent), and refinancing debt at lower rates, thus benefitting consumers.

Ofgem has accepted this argument through the inclusion of £845m of costs "*which when straight line amortised over the period corresponding to the maturity of those repurchased bonds would lead to adjustments over the RIIO-2 years of £280m*"[14]. However, Ofgem has not included all of the Cadent sale related costs and similar costs which were incurred prior to these buybacks, which if amortised in a similar way would lead to adjustment over the RIIO-2 years of a further £81m.

An industry-wide view of debt costs is a more appropriate way of setting the cost of debt allowance for the notional company

As we stated in our business plan submission, companies across all the energy network sectors (Gas Distribution, Gas Transmission, Electricity Distribution and Electricity Transmission) have issued debt with broadly the same average tenor and all are investing in similarly long-life assets under the same regulatory framework. There is therefore no good reason why debt costs or cost of debt allowances should differ across the sectors for the notional companies.

In calibrating the tracker length to capture *"a fair and reasonable estimate of the actual cost of debt likely to be incurred by a notionally geared, efficient company"*[15], Ofgem must ensure two things. Firstly, the allowance is consistent with the notional company, and secondly, the pool of companies upon which the calibration is performed is wide enough to retain the incentive properties. Both rely on basing the calibration on the widest possible group of companies.

The broadest possible sector average (including Electricity Distribution) provides the best estimate of notional company costs. Ofgem states *"We consider the volume of debt within the*

[14] "RIIO-2 Draft Determinations – Finance Annex", Ofgem, 9 July 2020, footnote 35
[15] "RIIO-2 Framework Consultation" Ofgem, March 2018, para 7.11

gas distribution and transmission sectors at over £23bn (excluding intercompany loans) to be sufficient to draw robust estimates of average debt costs and therefore calibrating to these expected costs would represent a reasonable debt allowance for a notional efficient operator in gas distribution and transmission sectors. Reducing the number of sectors to be combined further (so, for example, considering just GD combined with GT or ET combined with GT) would reduce the pool size and increase the risk that the smaller pool is skewed by specific company financing decisions rather than representing a reasonable allowance for a notional efficient operator"[16].

There are particular features of the Transmission and Gas Distribution sectors meaning whilst the total volume of debt is large, it is at risk of being skewed by specific company financing decisions and so does not represent a notional efficient operator as intended by Ofgem. This is primarily due to the presence of NGET, NGG and Cadent, who together represent a total of £17bn (excluding intercompany loans) of the £23bn of debt. As these were all part of National Grid plc until just 4 years ago, the number of completely unrelated debt portfolios within Ofgem's proposed calibration sample is small.

Ofgem has ruled out sector specific calibration as "*considering each sector individually could lead to skewed results because some sectors include only a small number of networks and could be largely or entirely impacted by individual network financing decisions and strategies (rather than anything intrinsic to those sectors)*"[17]. As explained in the preceding paragraph, the issues Ofgem identify still apply to calibration across the Transmission and Gas Distribution sectors combined as proposed in the DD. Ofgem has also stated "*we consider there to be merits to broadening the pool to include more networks and a greater volume of debt raised. This could allow us to gain a picture that could be considered more representative of a notional efficient operator*"[18]. On this basis exclusion of Electricity Distribution from calibration is not justified.

We also disagree with Ofgem that there are any meaningful impediments to including the electricity distribution networks in the cost of debt methodology.

Ofgem states "*because we do not have forecast totex or associated debt issuance forecasts for the ED sector, have not considered notional gearing for that sector in detail and have not been through as detailed a debt cost verification exercise for ED sector costs*"[19]. However, Ofgem has not tested how sensitive a whole industry calibration would be to these uncertainties. Ofgem already has full data on Distribution Network Operators' (DNO) debt via the Regulatory Finance Performance Reporting (RFPR) pack[20], was previously able to assess the cost of DNO debt more than 8 years into the future under a range of interest rate scenarios when setting RIIO-ED1 and has two years of data from this process to aid them in calibrating the RIIO-T2 and RIIO-GD2 cost of debt. The evidence supporting this cost of debt and the calibration of the trailing average index for RIIO-ED1 was also assessed by the CMA in the BGT appeal where they stated that they view a broader approach to setting cost of debt as being consistent with accepted regulatory practice: "*We attach more weight to the argument which recognises the challenges with identifying an effective efficiency test at the industry level. It is a common regulatory approach for sector regulators to consider debt costs at an industry level rather than an individual company level. In this light, GEMA's approach seems broadly consistent with accepted regulatory practice*"[21].

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[16] "RIIO-2 Draft Determinations – Finance Annex", Ofgem, 9 July 2020, para 2.47
[17] Ibid., para 2.42
[18] Ibid., para 2.43
[19] Ibid., para 2.44
[20] See for example "RIIO Regulatory Financial Performance Reporting – Regulatory Instructions and Guidance", Ofgem, 2 October 2018
[21] "British Gas Trading Limited v The Gas and Electric Markets Authority: Final Determination", CMA, September 2015, para 8.38

Ofgem also states *"if we were to include ED in this calibration exercise it would likely imply a debt allowance calibration for the ED sector, which we do not think is appropriate at this stage, particularly given we are not yet at a stage where we can have regard to the financeability of the ED notional efficient operator for RIIO-2"*[22]. Ofgem has already set the DNO debt calibration for the first two years (2021/2022 and 2022/2023) as part of RIIO-ED1, and cost of debt for DNOs is unlikely to change very quickly in the subsequent couple of years, making the assessment of a 'whole industry' cost of debt for the purpose of calibrating the RIIO-T2 and GD2 cost of debt allowances relatively insensitive to the reasonable range of uncertainties in the DNO debt costs. It seems reasonable to use the broadest possible dataset available to calibrate the RIIO-T2 and RIIO-GD2 tracker length and this would not prevent Ofgem from reaching a different conclusion regarding the calibration process during the RIIO-ED2 regulatory process if circumstances are found to change over the next couple of years.

Comparison to Electricity Distribution and water sectors shows a 12-16 year trombone is reasonable

Ofgem's proposed trailing average index of 10-14 years is very different from that used for RIIO-ED1 (where both Ofgem and CMA showed that even this would consistently underfund DNO costs out to 2023, even though the trailing average index would by then be 17 years) and by Ofwat in PR19. Ofgem's proposal therefore cannot credibly be seen as representing the *"estimation of the return debt investors expect from an efficiently run company (including both embedded debt raised prior to the price control period and new debt raised during the price control period)"*[23]. It is also insufficient to fund the Gas Transmission sector which has a trailing average best fit of greater than 20 years.

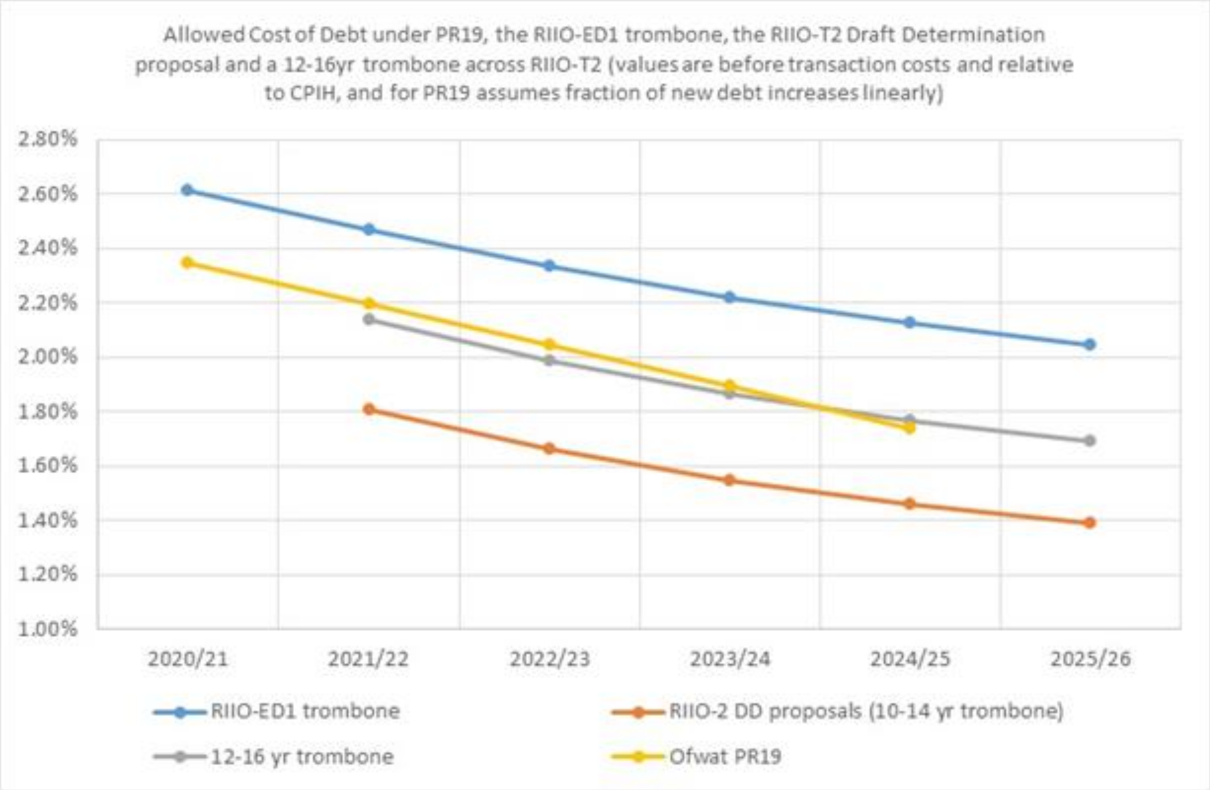
Ignoring transaction costs in each case, Ofgem's proposed trailing average for RIIO-2 gives an allowance for the trailing average cost of debt that in each year will be c.0.65% below the RIIO-ED1 trombone where even the ED1-trombone was not expected to cover the actual cost of debt of the DNOs[24] and c.0.35% below the PR19 level. This is illustrated in Figure 7:

[22] "RIIO-2 Draft Determinations – Finance Annex", Ofgem, 9 July 2020, para 2.45

[23] "RIIO-2 Sector Specific Methodology Decision – Finance", Ofgem, 24 May 2019, para 2.1; and "RIIO-ED2 Sector Specific Methodology Consultation: Annex 3 – Finance", Ofgem, 30 July 2020, para 2.1

[24] See for example Figure 9 "GEMA's interest rate scenario modelling results" in CMA's Final Determination of "British Gas Trading Limited v The Gas and Electricity Markets Authority", September 2015

Figure 7 Comparison of Allowed Cost of Debt across regulatory price controls[25]



In the light of the small number of companies in the proposed calibration, and since Ofgem has suggested no good reasons why the cost of debt in RIIO-T2 and RIIO-GD2 should be so different to RIIO-ED1 and PR19, the proposed 10-14yr trombone cannot be justified. It therefore needs to be amended to bring it more into line with the cost of debt allowances that have been set for RIIO-ED1 and PR19. We propose a 12 to 16 year trombone instead for RIIO-T2 and RIIO-GD2, and since these trailing averages do not include certain costs associated with raising debt, a fair estimate of the typical average level of these additional transaction and other costs should be then added (see below), as recognised by Ofgem[26].

Ofgem's current proposed approach would constitute an error, as it is unlikely to achieve Ofgem's stated aim that *"the cost of debt allowance should be a fair and reasonable estimate of the actual cost of debt likely to be incurred by a notionally geared, efficient company"* because of the small number of companies in the calibration pool, many of which have particular features that may make them atypical, when other equally good (or better) comparators, in particular the electricity DNOs, are being ignored. Ofgem's approach is also

[25] The lines for the 10-14 year trombone proposed in the RIIO-2 Draft Determinations and for a 12-16 year trombone are calculated from the actual and projected values for the iBoxx utilities index in the RIIO-2 WACC model published with the Draft Determinations.
The figures that are plotted for the RIIO-ED1 trombone are based on the allowance for 2020/21 taken from Ofgem's RIIO-1 cost of debt model, uplifted from an RPI to CPI basis using Ofgem's value of 0.8127% from the RIIO-2 DD, and then rolled forward using the projected values of the non-financials indices in the RIIO-2 WACC model published with the Draft Determinations.
The PR19 cost of debt allowance was based on an assumed 20:80 ratio of new:embedded debt on average across the 5 years, which would be consistent with an assumption that the proportion of new debt at the end of PR19 would be c.40% (see "PR19 final determinations: Allowed return on capital appendix", December 2019, section 6.1.3). Rather than plotting the fixed cost of debt for the 5 years of PR19 consistent with a constant 20:80 ratio, in order to facilitate comparison to the other lines in the chart we have shown the equivalent cost of debt in each year of PR19, excluding issuance and liquidity costs, if the fraction of new debt had increased linearly from 0% to 40% during the 5 years.
[26] "RIIO-2 Draft Determinations – Finance Annex", Ofgem, 9 July 2020, page 13

statistically less rigorous because it includes a smaller number of companies in the calibration, and therefore the error band is higher for the financing cost of the notional efficient company.

Deflating the nominal iBoxx

Ofgem are consulting on two options for deflating the nominal iBoxx:

- option (i), which was to continue using RPI breakeven rates and then to adjust for an assumed RPI/CPI wedge; and
- option (ii), deflating the nominal index in one step, using a single measure of inflation

We agree with respondents to Ofgem's Sector Specific Methodology consultation (SSMC) that the break-even rate is unsuitable as it is likely to include inflation risk premium, potentially offset by liquidity premium. Both are difficult to estimate and would create uncertainty for both networks and consumers over the funding of nominal debt costs. It also creates an additional step as an estimate of the RPI-CPI(H) wedge is then required to adjust to a real CPI(H) allowance, creating additional complexity.

We therefore support Ofgem's option (ii) to deflating the nominal index in one step, using a single measure of inflation, the OBR forecasts. However, we note that these are estimates of CPI rather than CPI(H). Deflating a nominal rate bond index with one measure of inflation and indexing RAV with another could lead to a network under-recovering the cost of its nominal rate debt even if it issued debt exactly in line with the bond index.

Additional borrowing costs

The iBoxx trackers that Ofgem uses in RIIO-1 and proposes to use in RIIO-2 to fund companies for the costs of debt funding do not capture the full costs that companies incur when raising debt finance. The 17bps allowance for additional borrowing costs in Ofgem's cost of debt allowance, relating to transaction costs, liquidity costs and the cost of carry is incomplete, and does not provide recovery for at least 20bps of costs related to:

- the 15bps incremental costs of issuing inflation linked debt, which are not captured by the nominal rate iBoxx index;
- the new issue premium, which incentivises participation in new bond issues; and
- an increased allowance for the cost of carry as the lower end of Ofgem's estimate is unrealistic.

When an appropriate allowance of more than 20bps for these extra costs is added to the DD proposal of 17bps, the required allowance for additional borrowing costs is at least 40bps.

Ofgem has ignored the incremental costs of issuing inflation linked debt vs nominal rate debt, which are not captured by the nominal iBoxx tracker mechanism

The notional company assumption is that 30% of net debt is funded through inflation linked debt. This reduces network companies' economic exposure to changes in inflation and reduces the volatility in credit rating ratios enhancing the financial resilience of network companies, particularly in periods of economic stress when inflation rates can diverge materially from the long run average. It is therefore common practice for network companies to hold inflation linked debt at levels that on average would be broadly consistent with Ofgem's notional company assumption of 30%.

However, inflation linked debt often trades at a higher spread than similar nominal rate debt. Ofgem should therefore ensure network companies are properly remunerated for the additional cost to issue inflation linked debt.

The iBoxx tracker mechanisms do not capture these costs as they incorporate only nominal rate debt. Ofgem needs to consider an appropriate way of calibrating the efficient cost of raising inflation linked debt within their assessment of additional borrowing costs. To date Ofgem has provided no indication of how they have considered this issue or why they have failed to provide for these costs in their DD.

NERA[27] find inflation linked debt costs of 15bps through comparison of two Orsted bonds issued simultaneously; one a 14 year nominal and the other 15 year CPI linked bond at UKT+128bps and ILG+238bps, respectively. The 110bps difference reflects two elements, the RPI-CPI wedge (as CPI bonds are quoted versus index linked Gilts which are indexed to RPI) and a further premium for the bond being linked to CPI versus a nominal bond, the 'CPI structure premium'. NERA conclude that the inflation premium has traded between 30bps and 100bps (due to changes in the RPI-CPI wedge) and support an estimate of 50bps for the inflation premium, which is consistent with additional inflation costs of 15bps, assuming 30% inflation linked debt, in line with the notional company.

This evidence is consistent with uncollateralised swap prices, which include credit risk, making them relevant comparator to bond prices. Indicative pricing for uncollateralised nominal to CPI swaps obtained from two banks is in the 40-45bps range for 15 years and in the 50-55bps range for 20 years. This is again consistent with additional inflation costs of 15bps when considered for 30% of the debt portfolio.

The iBoxx tracker does not capture the new issue premium

It is generally accepted that bond issuers pay an additional spread to incentivise participation in new bond sales. However, this cost is not captured by the iBoxx tracker as the premium is short-lived (potentially only for a matter of days). As the iBoxx measures trading yields at the end of each month, only bonds that are issued at the month end would be captured by the index, and only then for the first time on which they enter the index. It is therefore necessary for Ofgem to allow for this cost when calibrating the additional borrowing costs.

Cost of carry

Ofgem's midpoint of 6bps within the range of 1.5-11bps understates the cost of carry for NG. Our Treasury function is managed at the group level, with sterling balances principally related to our UK regulated business and dollar balances attributable to our US operations. Our average sterling cash balance for the last 6 months of 2019/2020 was £0.5bn on sterling net debt of £12bn, and average nominal iBoxx of 3.2% and return on cash deposits of 0.7%, over the same period. This implies a cost of carry of 10bps.

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

We do not agree with Ofgem's proposal to move to the iBoxx GBP Utilities 10yr+ index as it does not target a specified rating. By contrast, the iBoxx GBP A and BBB 10yr+ non-financial indices have a fixed rating, which ensures that networks will be funded in line with the notional company credit rating throughout RIIO-2 (i.e. the average of the A and BBB indices).

The iBoxx GBP A and BBB 10yr+ non-financial indices were used during RIIO-1 and have ensured that networks' cost of debt allowances have corresponded to a constant credit rating, even when network ratings, on average, have declined.

However, the iBoxx Utilities index proposed by Ofgem does not target a specific rating, so the rating will change over time. In fact, since 2010 its rating has declined from A-rated to a BBB+ rating today. If this trend continues consumers will be funding networks for a credit rating that is lower than the rating of the notional company, increasing costs to consumers. Conversely,

[27] "Review of Ofgem's DD additional costs of borrowing, and deflating nominal iBoxx", NERA prepared for the Energy Networks Association, September 2020, section 2

NERA find that if the rating were to return to pre-global financial crises levels then networks would be underfunded by 15bps on average over RIIO-2.

In addition, the Utilities index is heavily influenced by the activities of Ofgem and Ofwat (and government) as around 50% of the index is comprised of debt issued by companies (or their holding companies) whose revenues are determined by these regulators. This would leave the future cost of debt subject to the actions of two regulators and the financing decisions of a relatively small number of companies in the UK utilities sector. Ofwat rejected the Utilities index for this very reason *"We rejected the use of the alternative iBoxx GBP Utilities index on the basis that the share of UK water bonds in this index is high (26%, against 11% in our benchmark index). This would dilute one of the main advantages of using a benchmark index approach (i.e. the additional challenge provided by external comparators)"*[28].

We also note that Ofgem's preference in DD for moving to the more narrowly-based Utilities index (where UK water networks and UK energy networks make up just under 25% of the borrowings, respectively) rather than the more broadly-based indices suggests that Ofgem sees water company borrowings as comparable to energy network borrowings.

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

Whilst this is primarily a matter for SHET, its stakeholders and Ofgem, we do recognise that if SHET has had a materially different RAV growth profile from that of other network companies this will affect when its existing borrowings were raised, so a different trailing average index mechanism might be appropriate.

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

The principles and intended mechanisms for the financial framework need to be established and founded on solid grounds, before the mechanism can be implemented through a suitably constructed spreadsheet.

We therefore do not comment directly on the detail of the WACC allowance model spreadsheet at this stage but instead focus on the framework issues which inform the calculations; namely cost of debt indexation and risk-free rate (RFR) indexation.

Cost of debt indexation

Our more general comments on cost of debt indexation and how this should be specified are included in our response to questions FQ1 to FQ3 above.

RFR indexation

We can see merit in the indexation of the RFR but the methodology needs to be consistent with a wider robust process for setting cost of equity. In principle, we support use of a cost of equity tracker which is based on updating the value of RFR each year providing it is transparent, easily replicated, and capable of forming part of the annual iteration process.

The key requirement is that the basis of any update must be consistent with the approach taken in setting the opening allowed return for RIIO-2. The indexation methodology should not drive the framework used to set the opening cost of equity for the price control. Rather,

[28] "PR19 Draft Determinations, Cost of capital technical appendix", Ofwat, July 2019

the best estimate of RFR for the start of the price control should first be established based on the available evidence, and indexation should then be used to update this value each year to reflect changes in rates year-on-year.

In our response to question FQ9, we highlight new evidence, that has come to light during the past few months, that shows that unadjusted spot yields on government bonds (whether nominal or index-linked) cannot always be used as a proxy for the risk-free rate in the CAPM framework. To be used as a proxy for the RFR parameter that can be used in the CAPM, the spot yields on index linked gilts (ILGs) need to be adjusted for the following unique features of ILGs:

- a convenience ('money-like') premium attached to ILGs that pushes down government yields relative to the risk-free rate; and
- the gap between the corporate and sovereign risk-free financing rates

A recent report by Oxera[29] has reviewed the evidence and shows that an upwards adjustment of c.0.75% is needed to account for these features. (This is also discussed in our response to question FQ9 below.) Compared to the average projected RFR based directly on index-linked gilt yields in the DD of -1.48%, Oxera estimated a corresponding average across the years of RIIO-2 when taking account of these features that was -0.79%[30]. The difference between these two values shows the scale of the error that would be introduced by basing the RFR parameter used in the CAPM on the yields on government borrowings directly without taking account of the unique features of sovereign bonds.

In the light of this additional new evidence and the extra factor that needs to be built into the estimation of the RFR as a result, Ofgem may now find it simpler to set a constant RFR for the duration of RIIO-2. Such a fixed RFR would obviously need also to take account of anticipated changes in spot rates during the years covered by RIIO-2, based on the current forward curves.

Alternatively, Ofgem may still wish to retain indexation of the RFR to take account of changing yields each year, even once these additional considerations have been factored into the RFR estimate. This could be done either by updating the estimate based on Oxera's approach each year, taking account, for example of changes in AAA corporate debt yields, or more simply by adjusting the RFR set at the start of the price control by the changes in ILG yields (or nominal gilt yields and any change in the OBR's long-term CPI forecast) during the year. Thus, if Ofgem still wish to retain their proposed annual indexation of the RFR, basing this on changes in gilt rates each year and so updating the RFR each year through RIIO-2, this could still be implemented, provided c.0.75% is added to the rate that was calculated each year (from deflated nominal gilts or index-linked gilts) to reflect the unique features of government bonds.

Turning to other aspects of the proposed calculation, we have reservations over the derivation of the CPIH real RFR by application of an expected RPI-CPIH wedge to RPI-linked gilts, rather than from deflating nominal gilts by an appropriate estimate of future CPIH (in either case then adding the c.0.75% adjustment as explained above). Basing RFR on the RPI-stripped gilt data has the drawback that it would perpetuate use of an RPI index in a CPIH-based price control.

Furthermore, basing the value of RFR on ILGs would require the addition of an estimate or forecast of the RPI-CPI wedge in calculating the implied rates. There is already a degree of uncertainty over this value in any particular future period, and we note for example that Ofgem's proposed value of 0.8127% in the DD is lower value than most estimates in recent years (1.4% in RIIO-ED1, 1% in many recent forecasts (including in the May 2019 Sector Specific Methodology Decision (SSMD)), or 0.9% in the latest long-term OBR forecast. This uncertainty over the size of this wedge may increase in the future, and it may depend on the outcome of

[29] "The cost of equity for RIIO-2 Q3 2020 Update", Oxera prepared for Energy Networks Association, September 2020, Section 2.1, and the 'adjustment' in Table 2.5

[30] "The cost of equity for RIIO-2 Q3 2020 Update", Oxera prepared for Energy Networks Association, September 2020, page 14, where this is the 6-month figure which starts from approximately the same ILG yield as Ofgem's Draft Determinations for RFR

the recent HMT/UKSA consultation. There are therefore good reasons why the RFR on a real basis relative to CPIH should be derived and updated from nominal gilt rates, adjusted first for an appropriate estimate of CPIH, and then the unique features of government bonds, rather than the alternative (of starting form ILG yields, adding the RPI-CPIH wedge, and then adding the adjustment for the unique features of government bonds).

In any case, the 0.8127% estimate of RPI-CPI in the DD is based on a short-term view and so is not suited to use when uprating real or implied real long-term gilt yields from RPI to CPI when setting or updating RFR: Ofgem's value of 0.8127% for the RPI-CPI wedge, used in the 'WACC model" spreadsheet in the calculation of RFR, is inappropriate as it is a short-term view taken from a single forecast at a single point in time, and lower than the value of the wedge in 5 years' time in previous forecasts from the OBR. Instead, a longer-term and more stable view of the forward-looking RPI-CPI wedge should be used.

In the DD, Ofgem state an intention to preserve flexibility for themselves in relation to the approach using throughout RIIO-2 to update the RFR. Whilst we recognise that this flexibility might be needed if the RFR is based on ILGs, e.g. to account for the outcome of the recent HMT/UKSA consultation, it creates unnecessary and asymmetric risks for networks. This complication is avoided if the RFR is set and updated using nominal gilt rates as the starting point instead of ILGs.

In relation to other details of the proposed approach, we don't agree with use of average values across the month of October only when updating the RFR, as this introduces unnecessary additional volatility. Whilst it may capture the most recent market evidence it ignores interest rate variations over the year which we consider to be more reflective of investor expectations for a full year's investment. We therefore support a 12-month averaging period as it provides more stable estimates of the RFR which minimise the impact of circumstances which may be particular to that month. It also ensures consistency with approaches already adopted in the regulatory framework more widely for both cost of debt and inflation.

We do, though, agree that where gilt rates are used, it is preferable to use the 20-year gilt rate rather than the 10-year gilt rate, and note that these 20-year rates are likely to be more stable.

Finally, we note that our proposed approach, like that of Ofgem in the DD, relies on an implicit assumption that CPI and CPIH will, on average be equal. This creates further risk and uncertainty, as CPI and CPIH are not generally equal, and differentials can persist for many months or years. This issue also affects several other elements of the proposed price control, not just the RFR parameter. Ofgem are in substance proposing a CPI linked price control in many respects (the elements of the WACC), but a CPIH-linked control in others (e.g. RAV indexation), where this mismatch obviously creates risk. In our response to question FQ21, we suggest that it would therefore be better, simpler and more transparent to use CPI throughout, i.e. to set and index price controls to CPI rather than CPIH until such time as there are reliable CPIH forecasts, and CPIH-referenced financial instruments have become well-established in the market.

Allowed equity return questions

Throughout the development of the RIIO-2 framework, the estimation of cost of equity and the parameters from which it is calculated have been topics of extensive debate. Ofgem's proposed approach in the DD consists of three steps:

- Step 1 is to estimate the cost of equity using the Capital Asset Pricing Model (CAPM) evidence;
- Step 2 involves cross-checking the CAPM-implied cost of equity found in Step 1; and
- Step 3 is to apply a distinction between the returns that investors expect (ER, which is the result from steps 1 and 2) and the baseline allowed return (AR) on equity, by subtracting a 'wedge' from the ER to give the AR.

Under this approach, it is clearly paramount first to establish a suitable starting point under Step 1, as Step 2 involves cross-checks of the Step 1 estimate (rather than being a primary method for estimating the cost of equity), and Step 3 applies an adjustment to the value that is set by Step 1 (possibly as slightly modified by Step 2). It is therefore surprising that whilst the DD includes a number of questions both in relation to Step 2 (FQ7 and FQ8) and Step 3 (FQ9, FQ10 and FQ11), there are no questions in relation to the Step 1 calculations, other than in relation to one narrow issue (FQ5 and FQ6, concerning the relative risk between sectors) that affects just one parameter (beta) in the CAPM methodology.

We have therefore included recent evidence and updated comments on the other elements of the Step 1 calculation in our responses to FQ9 below, including:

- wider issues relating to beta estimation
- how values for Total Market Return (TMR) should be estimated, including items submitted to the Competition and Markets Authority (CMA) as part of PR19 water appeals;
- issues with the estimation of the Risk-Free Rate (RFR) that should be used in the CAPM estimation approach for cost of equity; and
- best estimates of the values for TMR and RFR that should be used.

We also refer back to our previous submissions (both our May 2018 and March 2019 consultation responses in relation to RIIO-2) and business plans, and the related supporting evidence from consultants.

Beta questions

Whilst Ofgem has asked questions about relative risk, it is not seemingly consulting on how equity beta should be estimated. This is concerning as there are critical elements that we and others (including economic consultants NERA, Oxera and Frontier) have previously commented on which have not been addressed by Ofgem and urgently need to be considered before FD. These issues, along with Ofgem's views on relative risk contribute to Ofgem understating its beta estimates, arriving at a range that is too low and does not reflect the risks borne by transmission networks. These issues include:

- the narrow scope and constituency of UK beta comparators, which represents a departure from regulatory precedent and ignores highly relevant evidence on energy network asset betas;
- the selective use of GARCH methods in measuring beta;
- the dismissal of beta evidence from 'decomposition' of non-pure play GB energy networks including National Grid; and
- the selective use of European beta comparators

Ofgem has now published additional consultants' reports (from CEPA and Robertson) on these issues alongside the DD. As beta estimation methodology and the suitable equity beta values for use in RIIO-2 are not explicitly being consulted on as part of the DD consultation process, we have included recent evidence and our updated comments on how the beta values for RIIO-2 should be estimated and the best estimates of beta that should be used for RIIO-2 in our response to FQ5 below.

In this response, we present evidence to show that Ofgem's beta estimate in the DD is too low and does not reflect the risks faced by energy networks. For the purposes of comparability, we first use and focus on asset betas calculated using a debt beta of 0.125. This is consistent with the value in Ofgem's DD when presenting asset betas. However, this is simply for the purposes of consistency and does not mean that we agree with the 0.125 debt beta figure. In FQ9 and appendix 3 we present a summary of evidence we have either already submitted through our business plan submission or as part of the Energy Network Association's (ENA's) evidence to the CMA as part of the PR19 appeals, or is contained in Oxera's latest cost of equity update report. This supports a debt beta range of 0-0.1 and a point estimate of 0.05.

Throughout our responses to FQ5 and FQ6 we make reference to Oxera's report for the ENA[31] and Frontier's report for NG[32], which both support our view that Ofgem's asset beta range is too low. The extract from Frontier's conclusion below summarises their findings:

"At each stage Ofgem has taken unjustified choices as to what evidence it will and won't consider. Across a wide range of topics, the effect of each of these choices is clear. Whether by design or by coincidence, we consider that all of the evidence that Ofgem has disregarded consistently indicates that the upper end of Ofgem's range has been set too low. As a direct consequence of this, Ofgem's selected point estimate for beta will also have been set too low.

While our review has found that a subset of the available evidence supports the lower end of Ofgem's range, much of that evidence comes from peers that it is reasonable to assume have a lower risk profile than GB energy networks.

In addition to this narrow subset of evidence, we have found a raft of further evidence, which has been entirely ignored by Ofgem, that strongly indicates that the upper end of Ofgem's beta range is far too low. NG's own beta – in particular over the last 5-6 years – is wholly inconsistent with the top of Ofgem's range, commonly sitting far above 0.39. The decomposition analysis also contains a wealth of evidence to suggest that the underlying GB energy network beta is likely to sit above Ofgem's upper bound. And a broader set of European evidence – while lending some support to the location of Ofgem's lower bound – strongly suggests that the upper bound has been set too low.

This substantial body of evidence cannot be ignored, in particular as Ofgem apparently intends to select a central value from its range. All of the evidence that the upper bound may be set too low supports an even stronger case that Ofgem's proposed point estimate has been set far too low."[33].

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

We fundamentally disagree with Ofgem's view that energy networks will hold similar systematic risk during RIIO-2 to water networks during PR19. Ofgem's conclusion dismisses a wealth of evidence that points to the contrary and is based on one very narrow source of

[31] "The cost of equity for RIIO-2 Q3 2020 Update", Oxera prepared for the Energy Networks Association, September 2020

[32] "Estimating beta for RIIO-2", Frontier Economics, September 2020

[33] Ibid, see page 18

qualitative evidence. We set out in detail the issues Ofgem need to address in their final determinations, in particular:

- Ofgem is wrong to dismiss direct market evidence from asset beta estimates (and their decomposition and re-composition), which provides robust, quantitative evidence of the higher systematic risk of energy networks relative to water networks.
- analysis by both Frontier[34] and Oxera[35] supports a higher asset beta range, reflecting a broader range of evidence, including NG plc asset betas, which should be considered a lower bound for energy network asset betas, and the decomposition and re-composition of UK energy network asset betas for NG and SSE. The analyses also show that Ofgem's DD beta figures were based on the selective use of EU comparators and of GARCH methods of measuring data.
- instead, Ofgem relies on CEPA's much weaker qualitative evidence ahead of the quantitative evidence. CEPA's work is far from conclusive and does not put appropriate weight on a key risk differentiator, complexity of capex.
- Ofgem's view is a departure from regulatory precedent. Ofgem has found energy risk to be higher than water as recently as RIIO-1 and there are clear indications that energy risk is increasing in RIIO-2 (see our response to FQ6).
- a wide range of consultant studies[36] and investor commentary[37] also support higher risk in energy networks compared to water networks.

With respect to the wider question of estimating the asset beta, to which Ofgem have not provided a consultation question, there is clear evidence that Ofgem's range is too low. Figure 8 below summarises Ofgem and CEPA's evidence (in grey) and Frontier's evidence (in blue). This clearly shows that much of the market evidence in Ofgem's DD supports a higher asset beta range, with the lower EU peer set, as defined by CEPA, resulting from a high-level analysis that does not properly assess the relative risk of the different EU regimes or provide the best justified criteria for including/excluding potential comparators.

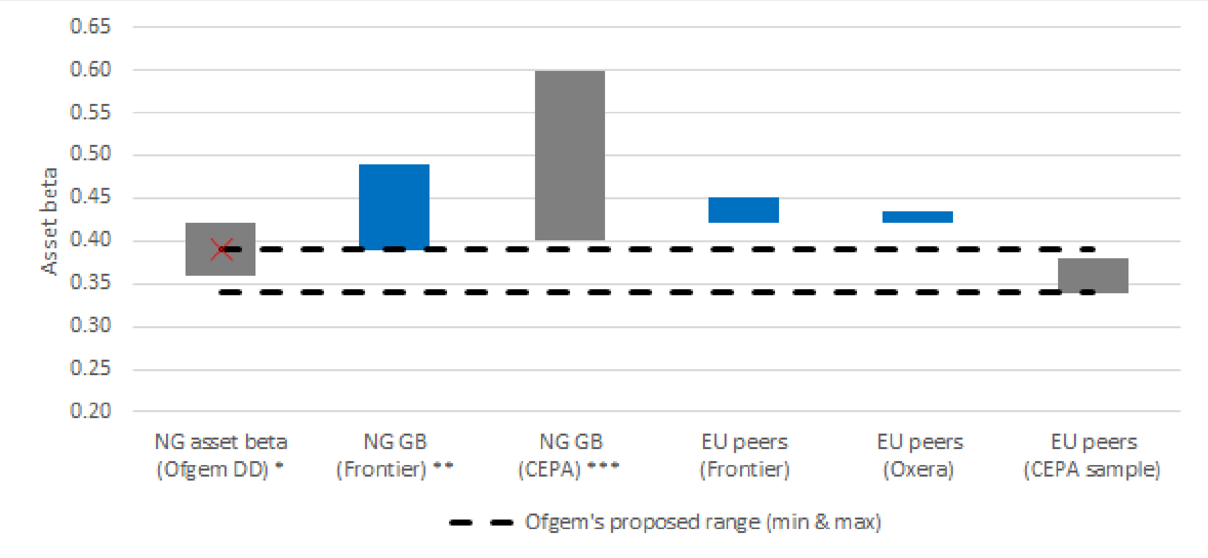
[34]"Estimating beta for RIIO-2" Frontier Economics, September 2020

[35]"The cost of equity for RIIO-2 Q3 2020 Update", Oxera prepared for Energy Networks Association, September 2020

[36] For example, "The cost of equity for RIIO-2 Q3 2020 Update", Oxera prepared for Energy Networks Association, September 2020, Section 3 and "Estimating beta for RIIO-2", Frontier Economics, September 2020, Section 4.2

[37] Recent examples include: Barclays report from 13 August "*...We believe power and gas networks have a higher structural beta than water...*" and Berstein's report from 3 August "*...the nature of projects, particularly in transmission,* ***involves significantly higher risk than the water sector*** *and there is considerable uncertainty in the transition to net zero.*"

Figure 8 Summary of Ofgem, CEPA, Oxera and Frontier's asset beta evidence[38]



* Data represents non-market value of debt data taken from Table 14 of Ofgem's DD, with the X denoting the average.
** 2- and 5-year windows with 2- and 5-year averaging periods[34]
*** Represents the range within which the vast majority of CEPA's NG disaggregated data sits, from 2014 onwards[35].
Note that all asset beta estimates are presented using a debt beta of 0.125 (for comparability purposes only, see FQ9 for our evidence in support of a debt beta of 0.05) except for Oxera's estimates, which use a debt beta of 0.05. We note that translating to a 0.125 debt beta would increase Oxera's asset beta estimates.

Ofgem must consider a much wider set of evidence and markedly expand its scope when assessing the systematic risk of energy networks during RIIO-2

Ofgem has ignored much of the evidence that is available to them in making their assessment on the risk of UK energy networks. Their reasons for doing this do not stand up to scrutiny and have the effect of achieving an historically low cost of equity[39] in the mistaken believe that this will make room for net zero investment on the consumer bill. This risks exacerbating an already downward skewed outcome that will jeopardise the very outcome Ofgem are keen to facilitate – the UK's ability to rise to the key challenge of our time, meeting the UK net zero climate change commitment. Failure to assess a wide range of evidence means Ofgem are falling short of fulfilling their statutory duties to have regard to regulatory best practice.

In order to make a complete assessment of regulatory risk, Ofgem should cast its net as wide as possible. We set out below quantitative analysis that takes this broader assessment approach and shows energy networks are higher risk than water networks. We then expand in more detail on the errors Ofgem have made in their methodology for assessing risk and include analysis performed by Frontier that shows Ofgem have consistently dismissed evidence that points to their asset beta range being too low *"...it [Ofgem] has rejected key and highly informative evidence for no good reason. As a result, in so far as it is possible to tell given the lack of clarity over what Ofgem has depended on in making its decision, this has led Ofgem to make an assessment of beta that is biased downwards"*[40].

[38] EU peer data taken from, respectively:
Frontier: "Estimating beta for RIIO-2", Frontier Economics, September 2020, Figure 42
Oxera: "The cost of equity for RIIO-2 Q3 2020 Update", Oxera, prepared for Energy Networks Association, September 2020, Table 3.3
CEPA Sample: "Estimating beta for RIIO-2", Frontier Economics, September 2020, Figure 42
[39] https://www.ofgem.gov.uk/publications-and-updates/ofgem-proposes-25-billion-transform-great-britain-s-energy-networks
[40] "Estimating beta for RIIO-2", Frontier Economics, September 2020, page 13

We provide a summary of the qualitative factors that show why energy is higher risk than water. Although this question seeks views on systematic risk, it should be recognised that very few risks are wholly systematic or idiosyncratic, and so a comprehensive consideration of this question (and also FQ6 below) would require a consideration of almost the full spectrum of risks faced by networks. CEPA's work identifies that there are higher dynamic risks in the energy sector compared to water. It is first unclear to us how CEPA can determine these risks are only dynamic in nature rather than having any systematic elements and secondly, even if the risks were dynamic in nature, how Ofgem are managing and rewarding investors for taking those risks within the framework.

Our analysis shows that Ofgem and CEPA's analysis fails to adequately take into account the risks arising from the greater complexity of capex in transmission and the uncertainty in requirements for gas and electric networks to invest in net zero infrastructure. Ofgem's consultants have also not properly reflected the increased risk resulting from the much-reduced predictability and consistency in the regulatory framework due to Ofgem's apparent readiness in RIIO-2 to make changes that couldn't have been anticipated and that break with past precedent even where underlying evidence hasn't changed.

Ofgem's Draft Determinations represent a narrow and biased interpretation of the evidence that fails to follow best regulatory practice

The framework is weighted to the downside across many aspects which means that it is particularly critical that risk and asset beta are assessed in the round. Examples include Ofgem:

- proposing to break from regulatory precedent from the well-established convention of aiming up in their estimate of cost of equity, which has been shown to be *"an optimal regulatory response to the uncertainty inherent in estimating the cost of equity"*[41];
- introducing a new and unproven 25bps deduction within the allowed return for anticipated outperformance;
- introducing low incentive ranges that are skewed to the downside; and
- imposing an unjustified and disproportionate net BPI penalty on average across the networks.

Given the above and the significant challenge of responding to the UK's net zero ambition now is not the time to move away so markedly from good regulatory practice when assessing evidence on risk and beta. Ofgem's arguments for ignoring highly relevant evidence are weak, and do not stand up to scrutiny:

- Ofgem has used CEPA's qualitative analysis of relative risk of water vs energy as justification for ignoring beta evidence from NG and SSE, the two listed groups with energy network exposure. However, a qualitative analysis is inevitably subjective, dependent on the relative weights applied to individual arguments. There is no good reason why a qualitative analysis should be relied upon in preference to direct market evidence that contradicts the conclusion of CEPA's qualitative assessment.
- Ofgem has also ignored decomposition evidence prepared by Frontier and CEPA in relation to NG and SSE's beta on the basis that the data is noisy. However, all beta evidence is noisy and the purpose of looking at the broadest possible evidence base is to ensure balanced conclusions can be drawn. Furthermore, there are clear trends and

[41] "Further analysis of Ofgem's proposal to adjust baseline allowed returns", Frontier Economics prepared for Energy Networks Association, September 2020

conclusions that can be drawn from a careful review of the evidence that Ofgem has too readily dismissed.

Ofgem's current approach which appears to focus primarily on just United Utilities (UU) and Severn Trent (SVT)[42] as comparators to estimate the beta range is not supportable and is a significant and unjustified departure from regulatory precedent. A balanced and complete review of Ofgem's own evidence allows markedly different conclusions to be drawn from those that Ofgem reach in their DD.

Table 14 of Ofgem's Finance Annex presents beta evidence over a range of estimation windows (2, 5 and 10 years) and averaging periods (spot, 2, 5 and 10 years) using both the market value of debt and book value of debt for SSE, NG, Pennon (PNN), SVT and UU. Given National Grid's asset beta reflects the risk of a group that comprises 91% regulated energy networks (albeit spread across the UK and US) it would seem the most relevant set of beta estimates when trying to establish an asset beta for UK energy networks, relative to SSE, the only other UK listed group with UK energy network exposure, which has a much larger non-regulated portfolio.

As Table 2 below summarises, in each instance within Ofgem's Table 14, NG plc's asset beta is greater than that of PNN, SVT and UU. This represents clear and highly relevant evidence that systematic risk is higher in energy networks than water networks that should not be dismissed in favour of CEPA's subjective and judgmental qualitative analysis.

Table 2 Analysis of Ofgem's asset beta as presented in Table 14 of the DD Finance Annex

Variance to NG's Asset betas (non MV of debt)							
Estimation window	Averaging period	NG less avg of water + NG	NG less water	NG less ST / UU average	NG less avg of water + NG	NG less water	NG less avg ST / UU
2 year	Spot	0.06	0.07	0.08	16.4%	23.2%	25.8%
2 year	2 year	0.03	0.04	0.06	8.8%	12.1%	17.6%
2 year	5 year	0.02	0.02	0.04	4.3%	5.9%	10.5%
2 year	10 year	0.01	0.02	0.03	3.5%	4.7%	8.8%
5 year	Spot	0.04	0.05	0.07	10.1%	13.9%	18.8%
5 year	2 year	0.02	0.02	0.04	3.7%	5.0%	9.1%
5 year	5 year	0.01	0.01	0.03	2.6%	3.4%	6.7%
5 year	10 year	0.01	0.01	0.02	2.1%	2.8%	5.7%
10 year	Spot	0.03	0.03	0.05	7.0%	9.6%	13.4%
10 year	2 year	0.01	0.01	0.02	1.4%	1.9%	4.3%
10 year	5 year	0.01	0.02	0.03	3.5%	4.7%	7.2%
					5.8%	**7.9%**	**11.6%**

Variance to NG's Asset betas (MV of debt)

[42] "RIIO-2 Draft Determinations – Finance Annex", Ofgem, 9 July 2020, paras 3.49 and 3.50

Estimation window	Averaging period	NG less avg of water + NG	NG less water	NG less ST / UU average	NG less avg water + NG	NG less water	NG less avg ST/UU
2 year	Spot	0.06	0.08	0.09	17.8%	25.3%	31.0%
2 year	2 year	0.04	0.05	0.07	9.9%	13.6%	21.9%
2 year	5 year	0.01	0.02	0.04	3.2%	4.3%	11.1%
2 year	10 year	0.01	0.01	0.03	2.1%	2.9%	9.1%
5 year	Spot	0.03	0.04	0.06	8.3%	11.4%	18.2%
5 year	2 year	0.01	0.01	0.04	2.6%	3.4%	9.6%
5 year	5 year	0.00	0.00	0.02	0.0%	0.0%	5.6%
5 year	10 year	0.01	0.01	0.03	2.1%	2.8%	7.2%
10 year	Spot	0.02	0.03	0.05	6.5%	8.8%	15.6%
10 year	2 year	0.01	0.01	0.03	2.2%	2.9%	9.4%
10 year	5 year	0.01	0.02	0.03	3.5%	4.7%	8.8%
					5.3%	**7.3%**	**13.4%**

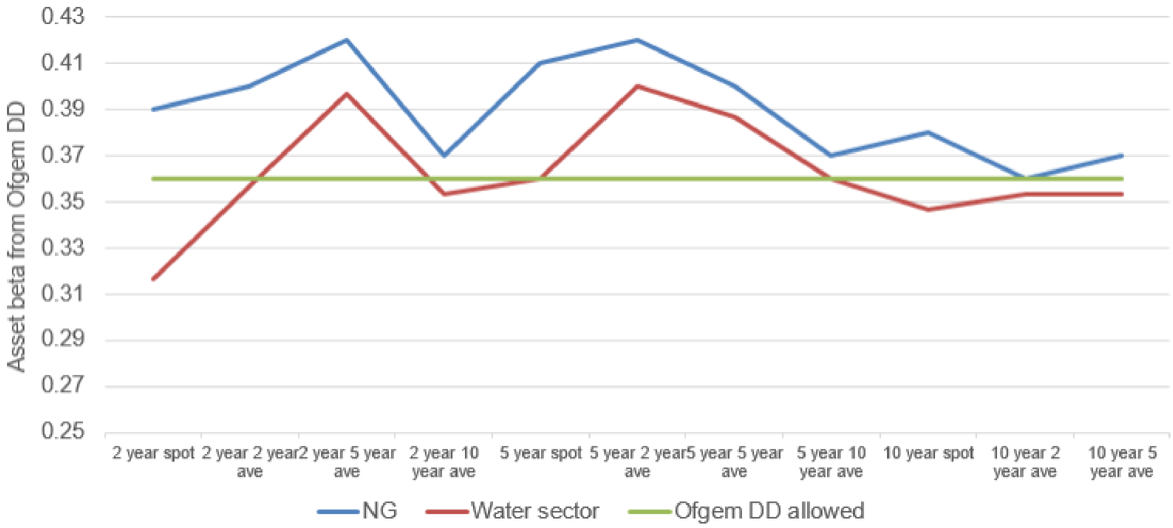
Frontier's report[43] for National Grid also finds that *"Even absent any adjustment, NG's group beta has generally been higher than SVT and UU betas throughout much of the last 10 years..."*. It also comments on Ofgem's Table 14, noting *"We are surprised that Ofgem has not commented on this empirical information on the relative risk across energy and water networks, preferring it appears to rely primarily on CEPA's more subjective assessment of relative risk"*.

Similarly, Oxera's report for the ENA[44] states *"National Grid's asset beta remains above the water companies for all frequencies and time periods"*.

The evidence from multiple sources is therefore highly consistent, including from Ofgem's own DD, in showing that the best UK proxy for pure play energy networks (the NG group) has a higher asset beta than all three listed water networks over multiple time horizons and averaging periods. This represents direct market evidence that energy is higher risk than water, meaning Ofgem needs to change course and reflect this evidence in their assessment of relative risk.

[43] "Estimating beta for RIIO-2" Frontier Economics, September 2020, Section 4.2
[44] "The cost of equity for RIIO-2 Q3 2020 Update", Oxera report for Energy Networks Association, September 2020, page 43

Figure 9 Asset beta data from Ofgem's DD



Finally, we note that Ofgem's proposed asset beta range has only limited support from their own economic consultant, CEPA, as highlighted by Oxera in the report for the ENA[45]: *"...Ofgem claims that CEPA's work supports an asset beta in the range of 0.34 to 0.39. However, CEPA's report is much more cautious. It notes that 'We have not been asked to produce an overall asset beta range and so we do not provide one. We have, however, considered whether the balance of relevant evidence that we consider within the scope of this report is consistent with Ofgem's estimates of the asset beta range.' One concludes that the limited evidence considered could support a wide range of asset betas, not only that proposed by Ofgem"*.

Ofgem has incorrectly put no weight on beta decomposition and re-composition evidence

NG plc's beta will be impacted by all the elements of its operations, of which 91% constitute regulated energy networks, split roughly evenly between our UK and US jurisdictions. This makes the resulting beta a good comparator for energy networks in the UK. In addition, we can disaggregate NG plc's asset beta into a GB, US and much smaller non-regulated component. Using betas for US peers which are far lower than UK counterparts (as agreed by Ofgem in the DD[46]) shows that under any reasonable configuration of assumptions the estimate for NG's GB asset beta would be higher than that of NG plc. This is consistent with Frontier and Oxera's findings, for example Oxera state: *"... the asset beta estimated for National Grid is likely to be an underestimate of the true asset beta of National Grid's UK regulated business. This is because the estimate presented in this report reflects elements of lower risk faced by National Grid's US business"[47].* A similar approach can also be taken for the SSE group beta. Both analyses show that a pure play GB network beta is higher than that of NG's group beta.

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[45] "The cost of equity for RIIO-2 Q3 2020 Update", Oxera report for Energy Networks Association, September 2020, page 49

[46] "RIIO-2 Draft Determinations – Finance Annex", Ofgem, 9 July 2020, page 190: *"We note the range of asset beta estimates using the 5yr specification in Frontier's analysis. US regulated companies range from 0.19 to 0.55."*

[47] "The cost of equity for RIIO-2 Q3 2020 Update" Oxera, report for Energy Networks Association, September 2020

Previous evidence we have submitted to Ofgem[48], showed that the direct decomposition of NG and SSE's group beta into its constituent parts offers evidence that the low end of Ofgem's range is not valid for GB regulated energy networks and that the high end of the range should be increased. Ofgem's main reason for disregarding the direct evidence that can be obtained through this approach is that CEPA say *"it is challenging to draw robust conclusions from the decomposition analysis of SSE and NG's group beta as submitted by the energy networks' advisors, particularly given the volatility in the results over time and between companies"*[49]

This suggests CEPA view the results as "too noisy" to interpret, yet the fundamentals of beta estimation are that there is always noise involved so to discard evidence on this basis is a hasty approach. A much better approach is to review all relevant information including beta estimates over different time periods for a range of relevant listed companies and use this data to make a judgement in the round.

When CEPA's results are reviewed they show that decomposition of National Grid's beta supports an asset beta for the UK networks of between 0.4 and 0.6 throughout the majority of the period since mid-2014[50] (there being just two brief periods when the asset beta sits respectively below and then above this range). Similarly, the decomposition of SSE's beta supports a GB energy network asset beta above 0.4 for almost all of this period (the exception being for a period of a few months in 2018 and 2019 – see CEPA Figure 4.3). This period broadly coincides with the RIIO-1 period and is after the impacts of the global financial crisis, that can be seen in beta values prior to 2012. In addition, the decomposition results for National Grid's UK networks have been consistently higher than those of the UK water companies since 2014 (see CEPA figure 4.11).

Frontier have also performed a disaggregation analysis on NG's and SSE's asset beta, with results that show GB asset beta values above those of NG's group asset beta values, consistent with CEPAs results. For example, for 2 and 5-year betas and averaging windows of 2 and 5-years the asset beta range was 0.39 - 0.49 for NGs pure play asset beta[51], supporting an asset beta range that is above that of NG's group asset beta and above Ofgem's asset beta range in the DD of 0.34 - 0.39.

CEPA provide more evidence through a 're-composition' of NG and SSE's asset beta. This approach requires an assumption to be made about the weight and asset beta for the component parts of NG and SSE's corporate structures in order to 're-compose' their respective group asset betas. In the case of NG for example, CEPA use UK water networks for NG's UK asset beta and US energy networks to estimate NG's US asset beta.

CEPA's 're-composition' results are consistently lower than the actual observed betas for these groups for the past 7 years (see CEPA's Figures 4.6 to 4.9). Whilst CEPA present several possible explanations for this difference, the single most likely explanation is that National Grid's GB regulated energy business is of higher risk (and has a higher beta) than the GB water companies or the companies included in CEPA's comparator group of European energy comparators.

The other possible explanations put forward by CEPA were (in relation to the modelling of National Grid's beta) that:

- the weights used may not be reflective of the expected share of future cashflows – but the results should not be highly sensitive to this assumption, and it is unlikely that both the NG and SSE modelling would be similarly affected.

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[48] "Review of Indepen report recommendations on beta estimation", NERA prepared for National Grid, 13 March 2019; and "Beta Decomposition", Frontier prepared for National Grid and SSE, 9 January 2020
[49] "RIIO-2 Draft Determinations - Finance Annex", Ofgem, 9 July 2020, para 3.50, page 41
[50] "RIIO-2: Beta estimation issues", CEPA prepared for Ofgem, 9 July 2020, Figure 4.1
[51] "RIIO-2: Beta estimation issues", CEPA prepared for Ofgem, 9 July 2020, Figure 13

- National Grid's US business may be slightly higher risk than the US energy comparators – though there is no evidence to support this.
- National Grid Ventures and other businesses may be slightly higher risk than our proxy for the market – again the results should not be highly sensitive to this assumption, and it is unlikely that both the NG and SSE modelling would be similarly affected

Frontier's findings are consistent with our own in that *"CEPA's constructed NG beta is systematically below the actual beta in both analyses, implying that the UK water and European samples used by CEPA only represent lower bounds for NG's pure play beta"*.

Therefore, not only should the decomposition results be taken into account when estimating beta, but they support the view that UK energy network companies (and specifically the Electricity Transmission companies) are exposed to higher risk and should have a higher beta and cost of equity in RIIO-2 than water companies in PR19.

Ofgem and CEPA's analysis of EU comparators relies on an assessment of the 'key features' of the EU regulatory regimes which are insufficient to fully understand the risks

Ofgem's DD refers to work performed by CEPA which concluded that only 6 of the 12 'longlist' of EU networks should be included in an EU peer set and that this *"supports, or even puts downward pressure on asset beta estimates"*.

However, as CEPA themselves state, they *"have not conducted a detailed relative risk assessment"*. Instead they have relied on "key features" of each regime. Frontier have reviewed CEPA's work and performed a more granular assessment of the relative risk of the EU regimes. Frontier only excluded those that are clearly not comparable or for which there are particular problems such as less than 50% operating income from regulated activities and low liquidity, in order to collect and take account of as much evidence as possible that is relevant to estimating beta. This more detailed analysis which draws on a broader set of market evidence allows for starkly different conclusions to that of CEPA's narrower evidence base:

- Firstly, in direct contradiction to CEPA findings that Belgium is the most relevant comparator (*"Comparability appears strongest, at a high level, for Elia and Fluxys"*[52]), Elia and Fluxys operate in low risk environments relative to the GB regime which is the highest risk. In fact, Fluxys should be excluded from the peer group as it doesn't meet CEPA's own liquidity test[53].
- Secondly, there is no reason to exclude Transelectrica from the peer set
- Thirdly, given the GB regime is the highest risk, that Frontier's list of EU comparators should represent a minimum threshold for the asset betas of UK networks.

Frontier have reviewed each of the tests that CEPA used to exclude Transelectrica from the sample and find no compelling reason to exclude it from the peer set. For example, CEPA state that it was not possible to assess liquidity for Transelectrica, but Frontier find bid-ask spread data is available from 2012 onwards, allowing sufficient data to assess liquidity and show it comfortably meets CEPA's own liquidity test.

As noted above, Frontier finds that Fluxys should be excluded from the sample as it does not meet CEPA's own liquidity test finding *"that Fluxys' bid-ask spread has generally been significantly larger than the 1% liquidity cut-off".* Frontier note that *"Even though CEPA finds a similar result, they state that "the resulting data [for Fluxys' beta] is not obviously lacking in robustness". It is unclear what justifies this statement".*

[52] "RIIO-2: Beta estimation issues", CEPA for Ofgem, 9 July 2020, page 43
[53] "Estimating beta for RIIO-2", Frontier Economics, September 2020, Figure 35

Frontier also determine that HERA and A2A should be excluded from the sample (consistent with CEPA), on the grounds that their regulated share of operating income is below 50%. Frontier therefore establish a sample of 9 EU networks, which yields an average asset beta range of 0.42-0.45, significantly higher than the slightly narrower sample of low risk networks selected by CEPA, which yields an average range of 0.34 to 0.38[54].

There is, inevitability, a degree of subjectivity in the choice of EU comparators that one selects. Throughout their report, Frontier take the approach of casting the net as wide as possible when gathering beta evidence, including in its analysis of EU comparators where they state: *"comparators should not be removed unless there are clear technical concerns on the robustness of the estimates"*, and on this basis only excluding the most illiquid stock (Fluxys) and the two companies with less than 50% regulated operating income (HERA and A2A).

By contrast, Oxera in its work for the ENA[55] have been more selective, limiting their sample to only the most liquid companies in what they describe as a *"'screening-out' methodology".* On this basis they arrive at a sample 4 companies: Enagas; REC; Snam; and Terna, stating that *"Based on the liquidity filters, we still consider that REN and Elia should be excluded from the sample of European energy networks"*. Whilst this approach is different to Frontier's selection criteria, Frontier do note that *"While we do not consider it appropriate to completely remove these firms (notably Elia and REN) to avoid a too limited sample, we do stress that the interpretation of their betas – and impact on the resulting range – needs to be assessed with significant care. In the round, simply retaining a midpoint based on simple averages when including these firms likely results in beta values that are lower than if a more refined positioning on the basis of our relative risk assessment was used.'*[56]*.* Oxera's and Frontier's peer sets are therefore different, however Oxera's approach also provides a range that is markedly higher than that identified by CEPA (Oxera find an average asset beta of 0.435, for a 2-year asset beta).

It is interesting, therefore, that whether you take the broadest possible approach to establish an EU peer set (such as Frontier), or a highly restrictive approach (such as Oxera), both approaches lead to much higher asset beta estimates than the more subjective approach taken by CEPA.

10-year sampling windows understate asset betas due to the impact of the global financial crisis and subsequent sovereign debt crises

Whilst the details of how Ofgem have determined the asset beta range is not set out in their DD, it appears that Ofgem is likely to have put significant weight on 10-year beta estimates.

There are a number of factors that make 10-year windows inappropriate for assessing the asset beta for RIIO-2. Most significant are the impacts on financial markets of the global financial crisis and subsequent sovereign debt crises. In particular, Frontier find that the status of regulated utilities as safe haven assets during the global financial crisis and sovereign debt crises may explain the decrease in beta estimates between 2011 and 2014, which is captured in 10-year sample windows[57] but not in the shorter 2 and 5-year windows except where these are combined with long averaging periods. This, combined with the significant changes in the RIIO-1 price control relative to the previous price control, and the fact that RIIO-2 represents a further marked change in regulatory arrangements led Frontier to conclude that an asset beta measure over a 10-year window may *"not be as [relevant as] those over shorter windows"*.

[54]"Estimating beta for RIIO-2", Frontier Economics, September 2020, page 18

[55]"The cost of equity for RIIO-2 Q3 2020 Update" Oxera prepared for Energy Networks Association, September 2020

[56] "Estimating beta for RIIO-2", Frontier Economics, September 2020, chapter 4.8

[57] This is the case for 10 spot values and for 2 year, 5year and 10year averages of 10yr betas.

Oxera also state a preference for shorter windows: *"we continue to rely on two- and five-year daily betas as our primary sources of evidence"*[58].

It is therefore important not to place undue weight on 10-year asset betas, simply due to the lower volatility that arises in a longer trailing average, if the information within the 10-year windows is fundamentally less relevant to the current environment than shorter averaging periods.

It is also instructive to look at commentary in PR19 about breakpoints. For example, Professor Alan Gregory et al, in a report for Anglian[59] find *"two significant break points, the first during 2014, the second right at the end of our data period. The first plausibly coincides with PR14. The second has the natural interpretation of being associated with the severe market disruption caused by SARS-Cov2/Covid 19".* These findings are instructive for Ofgem because they have placed significant weight on water sector asset betas.

GARCH models do not systematically lead to lower beta estimates

Ofgem asked Dr Donald Robertson to provide an update to the beta study he conducted in 2018[60] and refer to the *"materially lower results for asset beta when using a GARCH approach rather than OLS"* that he found in his work.

However, there are many different possible specifications of GARCH. Dr Robertson used the BEKK-GARCH specification. Ofgem have provided no justification as to why this particular specification was chosen ahead of others.

Frontier[61] reperformed Dr Robertson's work and expanded it to include five additional univariate GARCH models and compared the results to outputs from OLS estimates. They found for 4 out of the 5 listed regulated networks (NG, PNN, SVT and UU) that OLS estimates sit in the middle of the GARCH estimates, with SSE the only network for whom the GARCH models gave a lower beta estimates. They concluded, therefore that they could not find any evidence to support Ofgem's stated view that GARCH leads systematically to lower beta values than OLS.

Ofgem relies on CEPA's qualitative analysis ahead of the quantitative evidence, but CEPA's work is far from conclusive and excludes a key risk differentiator, complexity of capex

CEPA's July 2020 study is not a full assessment of risk across different sectors. For example, CEPA do not provide their view of an appropriate beta range, but merely opine as to whether they agree with Ofgem's range. It is unclear, for example, where within the range they think UK energy betas sit. It is also noticeable that CEPA's report is scoped to exclude a key driver of relative risk between energy (and particularly Electricity Transmission) and water which is the complexity of capex.

Within the study they note *"the overarching regulatory framework is very similar between the two sectors"* but also recognise a number of factors that would support the view that energy

[58] "The cost of equity for RIIO-2 Q3 2020 Update" Oxera prepared for Energy Networks Association, September 2020
[59] "A Response to "Further Comments Regarding Beta" by Europe Economics" Alan Gregory, Richard Harris and Rajesh Tharyan, June 2020
[60] "Estimating Beta", Donald Robertson, April 2018 https://www.ofgem.gov.uk/system/files/docs/2018/12/ofgem_dr_dec_2018.pdf
[61] "Estimating beta for RIIO-2", Frontier Economics, September 2020, Section 8.5

networks (and especially transmission networks) have higher systematic risks than water networks, which are summarised in Table 3.

Table 3 CEPA commentary on comparative risk of energy and water networks

Reference from CEPA July report	CEPAs commentary[62]
Page 5	"*However, depending on the weight placed on different components of risk* ***we recognise that GB energy networks may be judged riskier than water networks – or at least that the sources of systematic risk are sufficiently different that water networks are an imperfect investment substitute for a pure play energy network in RIIO-2****:* • *Investment in energy networks will be driven by factors such as the expected long-term use of gas and electricity networks. The scope for transformative investment is perhaps greatest in the electricity sector, potentially supported by the use of competition for specific high-value projects.* • *Equity holders in energy networks are invested in long-lived assets and so their expected returns in the sector may be sensitive to these long-term drivers and the cashflow risks they may create, to the extent they are cyclical and systematic*."
Page 25, Table 2,3	In providing a summary of dynamic risk analysis and in comparing energy and water CEPA finds that energy has higher risk factors: "*Materiality of change [in demand] likely to be greater in energy sectors*", "*Materiality of change [with respect to competition] likely to be greater in electricity transmission sector*" and "*Magnitude of transformation [in investment cycle] likely to be greater in electricity transmission sector; Focus on managed decline and decommissioning of gas network may reduce risk in some scenarios*".
Page 38	"*Energy and water networks will face different sources of dynamic uncertainty ... On balance it is difficult to conclude that these differences consistently indicate that energy networks are exposed to greater systematic risk than water networks (or vice versa). While the scope for change may be greater in energy networks,* ***based on current regulatory arrangements*** *greater uncertainty does not necessarily translate into greater systematic risk exposure.* ***Within the energy sector there may be differences, with electricity networks in our view most likely to be exposed to greater dynamic risk***." "*However,* ***depending on the weight placed on different components of risk we recognise that energy networks may be judged riskier than water networks*** *(though the converse may also be also true in relation to some sources of uncertainty such as climate change and resulting water resource pressure). Investment in energy networks will be driven by factors such as the expected long-term use of gas and electricity networks (e.g. in supply of heating or power generation). Equity holders in energy networks are invested in long-lived assets and so their expected returns in the sector may be sensitive to these long-term drivers and the cashflow risks they may create, to the extent they are cyclical and systematic.* ***As a consequence, European energy networks as a comparator group and investment substitute to a GB energy network may more closely reflect these sector-specific risks that GB energy***

[62] "RIIO-2: Beta estimation issues", CEPA for Ofgem, 9 July 2020

	networks are exposed to. ... *European energy networks may help to inform beta estimation for GB energy networks*"

Ofgem has found energy risk to be higher than water as recently as RIIO-1 and there are clear indications that risk is increasing in RIIO-2

Regulatory precedent from previous rounds of price controls in the UK has demonstrated that energy networks are generally considered to be higher risk than water companies. For example, Ofgem's RIIO-1 price control found a hierarchy of risk between NGGT, Gas Distribution and Water, which were reflected in the asset beta values of 0.34, 0.315 and 0.3, respectively, assuming a debt beta of zero.

It is unclear to us what has changed in Ofgem's view between RIIO-1 and RIIO-2 that means that energy can now be considered a similar level of risk to water. In fact, there are additional risk factors in RIIO-2 such as the uncertainty in requirements for energy networks as the country looks to move towards a net zero future and the much reduced predictability and consistency from one price control to the next that the RIIO-2 DD have demonstrated. It is therefore reasonable to expect that energy networks risks are even higher in RIIO-2 that they were in RIIO-1, relative to water networks (see FQ6 for our detailed response on the relative risks between RIIO-1 and RIIO-2).

In addition, Ofgem's statement on page 192 that "*... our approach is not to make future MARs equal to 1*"[63] significantly increases regulatory risk. It implies that Ofgem see no barrier to designing RIIO-2, or subsequent price controls, such that they are intended to deliver a MAR that is less than 1. This is a substantial break with all past precedent in price controls across many UK regulated network sectors (in particular both energy and water, including PR19)[64]. It represents a significant watering down of the commitments made to investors by Ofgem prior to RIIO-T1 when RIIO was first introduced[65]. It leaves companies and investors with no understanding of the basis on which to expect future price controls will be set, and so substantively undermines the confidence that investors might have that their investment will eventually be repaid. Given how little return investors will receive in the next price control (relative to the 'Terminal Value' at the end of the price control), the cost of equity will need to be increased significantly, to compensate investors for the increased risk they now appear to face in relation to future price controls.

[63] "RIIO-2 Draft Determinations - Finance Annex", Ofgem, 9 July 2020, page 192

[64] Under the 'building block' approach previously employed in both water and for energy networks in the UK, allowed revenues are based on: allowances for 'fast' money (previously opex); non-controllable costs; RAV depreciation; incentive revenues (+ve or -ve); allowances for expected tax costs, and allowed return calculated from WACC x the company's estimated cost of capital. Past price controls have therefore been set in both sectors in a way that is at least implicitly expected to result in a MAR of 1, albeit actual outturn MAR values will inevitably depart from 1 as market expectations of outturn parameter values and performance gradually diverge from the regulator's estimates

[65] One of the key components of the RIIO model as set out in the opening 'Conclusions' section of the RPI-X@20 decision in Ofgem's October 2010 document "RIIO: A new way to regulated energy networks" concerned the principles for ensuring efficient delivery is financeable: "*We will ensure that efficient delivery of outputs is financeable by committing to published principles for setting a weight average cost of capital (WACC)-based allowed return to reflect the cash flow risk of the business over the long term.*"; these cost of capital returns form one of the key building blocks in the framework of UK regulation, and are calculated by multiplying the allowed percentage return (WACC) by the licensee's Regulatory Asset Value (RAV). as explained for example in the RIIO-1 ET and GT Financial Handbooks; and "Paragraph 12.19 in Ofgem's October 2010 RIIO Implementation handbook explained that "*The RAV provides a commitment on the revenues to be raised from future consumers during subsequent price control periods*".

Consultant studies support the view that energy risk is higher than water

A number of previous studies have considered the relative risks of energy and water networks and identified a range of factors that would support the view that energy networks (and especially transmission networks) have higher systematic risks (and so should have a higher beta) than water networks.

- The key issues are rapid technological change in energy compared to water, and an increased focus on decarbonisation (which creates a potential exposure to stranding risk, as well as uncertainties relating to the future role of NGG and NGET) both of which give reasons to believe that the fundamental risk of energy networks is greater than that faced by water networks.
- It follows that energy networks are likely to be seen as being at a higher risk of political interference.
- In energy, the lack of clear and direct benchmarks for transmission (and especially NGET and NGG) relating to large parts of their expenditure exposes these companies to much greater regulatory risk than water (or energy distribution) companies.
- Energy networks face higher risk than water networks in relation to system operability risks, as well as the potentially significant reputational risks associated with any asset failures that can be extremely high profile, especially in relation to transmission (as the August 2019 system issues illustrated).
- The nature of capex works is also different in energy, and especially in transmission, from that in water. Much more spend is on large and complex one-off projects, which is exposed to greater project and regulatory uncertainty and risk as evidenced, for example, by the unprecedented cuts to NGET and NGG's RIIO-2 business plan totex levels in the DD. The risks on repeated, more standard and smaller scale projects such as in water (and distribution) is much smaller, as the cost of such projects is much easier to predict and benchmark. There is also an asymmetric risk in transmission due to the scale of totex that could be delivered through ex-post uncertainty mechanisms which provide limited (or no) opportunity for outperformance but significant risk that at least some of the costs that are incurred are not subsequently approved.
- Energy networks (and especially transmission) face greater cyber risk through greater reliance on digital assets.
- Risks associated with the development of competition are more established in energy transmission than in water.
- Frontier have performed analysis of the asset stranding risk in GT based on gas demand under each of the four FES19 scenarios. They found that under the two net zero compliant scenarios (‘Two Degrees’ and ‘Community Renewables’) between 8.2% and 12.0% of the total gas transmission asset could be stranded by 2040. It follows that the higher the asset stranding risk, the higher the premium in return on equity terms required to compensate investors for the additional risk faced. Frontier show that the value at risk represents a premium to cost of equity of 0.99%-1.53%, which is not meaningfully addressed by reductions to asset lives proposed in NGG’s business plan.

Investors view energy as higher risk than water

The primary evidence has been discussed above in our discussion of the quantitative evidence in relation to energy and water asset betas. In addition to this there has been sell-side commentary that also supports this view.

Table 4: Summary of sell-side comments on energy vs water risk, since 9 July 2020

Bank	Date	Comment
Bernstein	3 Aug 2020	"*... Allowed returns and incentives are also lower than that offered to* ***the lower risk UK water sector***." and "*There is little consistency with principles adopted in prior periods such as higher relative risks vs the water sector, lower gearing usually resulting in a higher allowed WACC, etc*." and on page 6 "*Within the UK context, the returns on offer are even lower than what has been granted to UK Water companies although the nature of projects, particularly in transmission, involves* ***significantly higher risk than the water sector*** *and there is considerable uncertainty in the transition to net zero*."
Barclays	13 Aug 2020	"...*We believe power and gas networks have a higher structural beta than water – and Ofgem's Draft Determination is as similar as can be between relative betas with 0.71 for water and 0.72 for power and gas*."

These recent views are also consistent with views that have been held by investors over the long term. For example, at Ofgem's City workshop in February 2011, our representatives recorded investor comment that included "*a view that gas and electricity were increasingly being seen as more risky, both in absolute terms and relative to water*".

Potential cross sector benchmark data needs to be treated carefully, but there are clear indications that risk is increasing between RIIO-1 and RIIO-2

In light of the above information and assessments, it is surprising that Ofgem's DD seem to reach the view that the beta value used for RIIO-2 should be based on those for SVT and UU as these reflect Ofgem's "*current judgement that pure-play energy networks hold similar systematic risk to pure-play water networks*" (see, for example, paragraphs 3.49 and 3.54).

We recognise that there are limitations as to how compelling a qualitative comparison of risk factors in different sectors can be. As CEPA have recently demonstrated in their 9 July 2020 report for Ofgem, such a comparison can run to many pages. Whilst much of such a commentary may be non-contentious, other points are likely to be less so, and as a result the whole assessment is unlikely to end up being seen as objective proof. However, even when attempts are made to augment the assessment of qualitative factors with some quantitative comparators, the results are of limited value because of the judgments that go into setting cost allowances and performance target levels and the inevitably limited scope of these quantitative comparators.

For instance, a simple comparison of the totex:RAV ratios and incentive rates (or sharing factors) in different sectors can be misleading, as not all totex is equally risky (or uncertain). For example:

- large complex one-off capex projects have greater uncertainty and therefore construction risk than small, standard projects or annual opex. As a result, energy network (and especially transmission) are exposed to higher risk than water companies. Think of the perspective of an investor – given two investments offering the same return, would they rather invest in a business with a large number of repeatable, standard projects or one with the same level of capex made up of a few more complex, less certain projects?

- The incentive rate that is applied to deviations in totex from allowances is only one of the factors that influences the extent to which companies are exposed to the risk of incomplete cost recovery. The risk faced by networks in relation to different categories of spend will depend on the regulatory frameworks that are applied to these. Ex-ante allowances for annual opex spend or on repeated smaller-scale capex projects which can be reliably benchmarked creates much lower regulatory risk (as well as lower project risk) than one-off bespoke expenditure subject to ex-post efficiency and need reviews. The changes in regulatory mechanisms proposed for RIIO-2 have significantly increased regulatory risk for transmission networks in energy compared to water.
- A similar point was also noted by CEPA, on page 29 of CEPA's report "*Relative to the water sector, the RIIO-2 price controls also have slightly lower totex-to-RAV ratios and lower totex sharing factors. Both sectors use benchmarking to set cost allowances. This would indicate that RIIO-2 would be lower risk for this category than water. We are however cautious of the risk of the different type of investment to be conducted; if investment in water is more linked to maintenance activities with more certain cost allowances and a reduced distribution of plausible outcomes relative to energy, this would run counter to the relationship posited above*". This point is potentially further reinforced for the transmission sector given the lack of immediate peers to use for benchmarking purposes.

The conclusion that energy is higher risk than water is also supported by 'single company' Dividend Discount Model results

The above conclusion that energy is higher risk than water is also supported by 'single company' Dividend Discount Model results for the cost of equity of the listed water companies and National Grid. Oxera's 2018 report for the ENA[66] showed these were higher for National Grid than ST, UU or PNN even though NG's gearing was lower, and this pattern was confirmed by the updated results in Oxera's November 2019 study for the ENA[67]. Oxera noted that "*As in the previous report, the cost of equity estimates for National Grid are still the highest in the comparator sample, further supporting the view that the fundamental risk of energy networks is greater than that faced by water networks*".

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

a) RIIO-1 and RIIO-2,

Most importantly, from the perspective of investors, the systematic risk they face doesn't just depend on a company's activities and the regulatory framework during RIIO-2, as most of a company's value depends on returns under subsequent price controls. When considered in this light, the systematic risks have, if anything, increased from the lead-up to RIIO-1 to now, because of the combination of:

- the uncertainty in requirements for energy networks into the medium and longer term - for both gas and electricity, and especially for transmission - as the country looks to move towards a net zero future; and
- investors will now have reduced confidence in how returns will be set compared to the lead up to RIIO-T1, given the much-reduced predictability and consistency (from one price control to the next) that the RIIO-2 DD have demonstrated.

[66] "The cost of equity for RIIO-2", Oxera prepared for Energy Networks Association, 28 February 2018
[67] "The Cost of Equity for RIIO-2 Q4 2019 Update", Oxera prepared for Energy Networks Association, 29 November 2019

Increased uncertainty in the quantum of totex and delivery model

Changes to the framework from RIIO-1 to RIIO-2, at least for transmission, have increased risk. Levels of spend and sharing factors cannot just be simply compared if the levels of allowed expenditure have been set so differently from in the past; NGGT starts RIIO-2 with allowances of around three quarters of its RIIO-1 spend to run and maintain the transmission network. The extent of spend subject to UMs (and future efficiency assessment) significantly increases risk – it's not just about sharing factors, but about whether spend carried out by network even gets shared or is at (or is perceived to be at) increased risk of being disallowed completely under the new framework.

Uncertainty around what is required to be delivered in RIIO-2 has increased risk compared to RIIO-1 and is not compatible with low returns or low financial resilience. There is an increased risk of stranded assets for gas as a result of the requirements for industry change in response to climate change becoming more imminent, in spite of the reduced asset lives that have been proposed. Frontier highlight that *"existing gas networks are now expected to become stranded to at least some (possibly material) extent. We are aware that some investors will at present not consider investment in conventional gas infrastructure owing to this risk. We also note that stranding risks are highly likely to be systematic, not idiosyncratic, as regulator attitudes and their ability to support investors will be heavily dependent on the wider strength of the economy. When the economy is weak, unemployment is high and real wage growth low, steps to protect the interests of investors are likely to be highly unpopular."*[68].

Ofgem's Table 19 compares the totex:RAV ratios for RIIO-2 to RIIO-1, but fails to recognise that not all totex is equally risky (or uncertain), for example:

- large complex one-off capex projects have greater uncertainty than small, standard projects or annual opex;
- the incentive rate that is applied to deviations in totex from allowances is only one of the factors that influences the extent to which companies are exposed to the risk of incomplete cost recovery. A further aspect to be taken into account, which is potentially more important than the sharing factor, is whether companies face the risk that costs that are incurred in good faith may actually get completely disallowed. (For example, NGGT commenced work on the Feeder 9 pipeline under the river Humber, incurring costs in good faith. However, Ofgem initially refused to fund the project stating "*unless new information came to light during the consultation, we would reject NGGT's request for funding*", whilst the final decision only awarded allowances of £111m against our cost assessment of £140m, in 09/10 prices. This illustrates the very real and significant risk that networks take in progressing projects ahead of funding being agreed.) The significant growth in Uncertainty Mechanisms in the DD raises this risk to a much higher level than has been seen previously.
- the risk of different categories of spend will depend on the regulatory frameworks that are applied to these. Ex-ante allowances for annual spend which can be reliably benchmarked create much lower regulatory risk than one-off bespoke expenditure subject to ex-post efficiency and need case reviews. The changes in regulatory mechanisms between RIIO-T1 and RIIO-T2 have significantly increased risk, even if there is a lower level of spend in RIIO-T2 (albeit, upward revisions are required to totex allowances between now and Final Determinations).

Reduced confidence in the predictability and stability of energy regulation

[68] "Estimating beta for RIIO-2", Frontier Economics, September 2020, Executive Summary

Ofgem have made significant changes in the framework between RIIO-1 and RIIO-2. The magnitude and pace at which these changes have been made both individually and in aggregate give cause for concern for investors about the stability and predictability of the framework.

Ofgem's DD represents a significant departure from this cornerstone including lower returns than UK and international comparators, downward skewed incentives and arbitrary judgements.

Ofgem's statement on page 192 that *"... our approach is not to make future MARs equal to 1"* significantly increases regulatory risk. It leaves companies and investors with no understanding of the basis on which to expect future price controls will be set, and so substantively undermines the confidence that investors might have that their investment will eventually be repaid. Given how little return investors will receive in the next price control (relative to the 'Terminal Value' at the end of the price control), the cost of equity will need to be increased significantly, to compensate investors for the increased risk they now face.

Finally, Ofgem suggests that certain features of the RIIO-2 price controls mitigate some risks to some degree, but these will only have a narrow and limited effect on the overall risk exposure:

- RAMs and ODI caps, but these only really apply to remove the low probability tails of the return and outcome distributions; and
- greater use of indexation. Debt, equity and RPE mechanisms limit systematic risks but debt was already indexed, RFR indexation in relation to cost of equity will have a relatively low impact (especially once a more appropriate value of equity beta at notional gearing is used) and the current unweighted labour RPEs exposes us to more general labour trends that are not relevant to our business.

On balance, therefore, when seen in the round, risks have gone up between RIIO-1 and RIIO-2.

b) distribution and transmission networks,

There has long been an acceptance and recognition that transmission is higher risk than distribution. This is one of the reasons why Ofgem set a lower notional gearing and higher notional equity beta for transmission networks in RIIO-1 than for Gas Distribution and Electricity Distribution.

- The lack of clear and direct benchmarks on transmission exposes these companies to much greater regulatory risk.
- The issues referred to in (a) above apply particularly to transmission and mean that transmission has higher risk than distribution. In particular, NGET and NGG face higher risk because of the complexity and uncertainty around our capex levels, including the impact of large, bespoke or one-off projects that come with high construction risk in comparison to a portfolio of fairly similar projects for Gas Distribution Networks and Electricity Distribution Network Operators.
  - By its nature capex in transmission infrastructure is more one off and bespoke in nature than opex or most of the expenditure by distribution companies. No two projects are exactly the same, and there will always be a raft of local factors that may emerge and drive unanticipated cost.
  - The complexity and uncertainty involved in the projects within the capex programme, including the concentration of large and discrete projects is greater in transmission. With a high concentration level of large complex projects, the capex programme is even more exposed to individual projects difficulties, idiosyncratic factors or regulatory risk on one of the large, complex projects. In contrast, a capex programme consisting

of a larger number of smaller projects would be less prone to uncertainties and risks posed by individual projects.

- Re-nationalisation risk may have declined in December 2019 but has not disappeared, it is really just a risk that has in the short term been deferred.
- Gas and Electricity Transmission both have features that make them higher risk than water (and Electricity and Gas Distribution). Stranding risks for gas have increased since RIIO-1, and become more immediate, and in electricity the range of future uncertainty under different net zero scenarios is now much higher than in the past.

The additional risks of transmission networks have been illustrated in the BPI penalties issued by Ofgem, which are weighted significantly towards the transmission networks rather than the gas distribution networks. This is due to the way in which Ofgem has designed the BPI which unfairly penalises transmission companies due to features of the sector which are beyond their control, namely, transmission companies have larger, less frequent, less standardised, less repeatable projects and this is a sector where there is more change happening because of the large increase in renewable generation. This approach has appreciably increased regulatory risk.

An important observation is that in RIIO-1 Ofgem set a lower notional gearing for Electricity Transmission (55% for the SPT and SHET, 60% for NGET) and for Gas Transmission (62.5%) than for Gas Distribution (65%) and Electricity Distribution in RIIO-1 (65%). This was a reflection of their perceived relative risk – see RIIO-GD1 FP Finance document paragraph 3.1 "*...The proposals reflect our view that the GDNs face notably less cash flow risk than the transmission companies will face over the same period under their price control (RIIO-T1)...*".

Similarly, for RIIO-2 Ofgem are now proposing a lower gearing for the Electricity Transmission companies (55%) than for Gas Distribution (60%), which is consistent with the trend in the previous RIIO-1 controls that transmission should have a lower gearing because it faces higher risk.

c) gas transmission and electricity transmission,

As explained above, both Electricity Transmission and Gas Transmission have sector features that mean they are higher risk than distribution. When making comparisons between the two transmission sectors, the complexity of capex is greater in electricity with the electricity sector also facing potentially much greater levels of spend with a corresponding greater uncertainty in its recovery given the proposed ex-post nature of RIIO-2. However, as we highlight above the gas transmission sector faces a much higher asset stranding risk even after the effects of shorter asset lives are taken into account.

Regulatory precedent, of both allowed equity return and gearing levels set out that Electricity Transmission is higher risk than Gas Transmission. The gearing differential is also maintained in DD. From a market data perspective, we are hamstrung by limited comparators. National Grid owns both electricity and gas transmission and SSE have only electricity networks but are not pure play in nature.

On balance, electricity transmission is probably higher risk than transmission, with the gearing difference in RIIO-2 perhaps reflecting that differential. We do note though that the difference has likely reduced since the inception of RIIO-1 as shown by metrics such as totex to RAV.

d) gas and electricity?

As we have set out in our answers to FQ6(a) to FQ6(c) the risks for gas and electricity are different, as are the risks for transmission compared to distribution. It is difficult to discuss the risk generally across all gas networks compared to the risk across all electricity networks, however we offer some points worth considering:

- As with our answer to the question of relative risk between Electricity and Gas Transmission, we would suggest, on balance, that electricity is higher risk than gas;
- Regulatory precedent would agree with this sentiment. When allowed return has been set contemporaneously, electricity networks have attracted a higher return.

Step-2 implied cost of equity consultation questions

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

We do not agree with Ofgem's use of gearing as a cross-check to the CAPM derived cost of capital. When the method is reviewed it reveals errors that when corrected show that Ofgem's cost of equity parameters and allowed cost of equity are too low. These errors include:

- Ofgem incorrectly uses a value for the cost of debt in this cross-check that is a weighted average of embedded and new debt;
- Ofgem's choice of CAPM parameters is incorrect, in particular Ofgem's application of the cross-check is affected by a value of RFR that is too low; and
- Ofgem has chosen to apply the cross-check using beta values for particular data samples that give amongst the lowest asset beta values in the DD table 14, rather than beta values that better represent the spread of values in table 14.

However, the question of the impact of gearing on beta and cost of capital applies first, and more importantly, before cross-check even apply, in relation to the principal estimate of the cost of equity made under Step 1 - The Capital Asset Pricing Model evidence. This is because the evidence of raw beta values from comparator companies will relate to organisations which have different gearing levels. As equity beta depends on gearing, the observed raw beta values for different companies can only be compared, and used to establish a well-justified view of the beta for a UK energy company, once they have been adjusted for the companies' different gearing levels. This means that gearing must be taken into account by converting the observed market beta values to an asset beta (or by converting them to a notional equity beta at the assumed notional gearing level).

We therefore first consider the issue of adjusting for gearing in relation to the estimation of CAPM parameters under Step 1 of Ofgem's methodology.

Step 1 gearing considerations

There is a long-established methodology that has been used by sector regulators in the UK and by the CMA to convert raw observed market beta values for actual companies or comparator companies to a 'notional' equity beta at the assumed notional gearing level, which is then used in the CAPM formula to calculate the allowed notional cost of equity (allowed equity return). This involves de-levering the observed raw beta values to give asset beta values, then selecting a representative asset beta to use for the regulated company, and then re-levering this asset beta to a notional equity beta value at the regulator's chosen level of notional gearing for the price control.

In the SSMD, Ofgem proposed two innovations that would depart from this standard approach, which was used recently, for example, by Ofwat in PR19.

- Ofgem proposed to use an estimation of gearing that would reflect Ofgem's estimation of EV:RAV, rather than using the actual gearing of the company that has been observed in the market. Ofgem referred to this as the EV:RAV adjustment. We support Ofgem's decision in the DD now to exclude the unjustified EV:RAV adjustment from the Step 1 estimate of cost of equity using CAPM, for example in calculating the asset beta values (presented in Table 14 of the DD); and

- Ofgem proposed to use an estimation of gearing that would reflect Ofgem's estimation of the market value of debt (Ofgem referred to this as the MVF adjustment). We disagree with this proposed MVF adjustment, as explained more fully below. Ofgem should use the standard de-levering/re-levering approach, so that the observed market beta values for different comparator companies can be compared and taken into account.

Step 1 gearing considerations, EV:RAV Adjustment

Multiple submissions from network companies and consultants have explained why the first of these innovations is flawed, contrary to finance text-book theory and inconsistent with best practice. Even Ofgem's consultant, CEPA, does not appear to agree with Ofgem's previously proposed approach on this point (or indeed the alternative adjustment previously contemplated by Indepen in the re-gearing step), as:

- adjusting the observed market gearing for a RAV >1 would not be consistent with CEPA's stated preference for use of market evidence *"where possible as it is more consistent with principles of corporate finance theory and asset valuation"*[69]; and
- noting also CEPA's comments that:
    - there would be a stronger case for including any such adjustment in the re-gearing step rather than the de-gearing step (albeit the modified notional gearing would then need to be used in weighting the cost of debt and cost of equity when calculating the allowed WACC, so the adjustment would have little effect on the overall allowed return); and
    - even though the case for making such an adjustment would be stronger in the re-gearing step, there would still be substantial regulatory process issues that, in CEPA's view, would need to be considered and addressed before applying such an adjustment[70].

It is therefore unsurprising that Ofgem appears to have dropped this unjustified EV:RAV adjustment from the Step 1 estimate of cost of equity using CAPM in the DD, for example in calculating the asset beta values (presented in Table 14), and we support this. We note, though, that Ofgem appears to have misunderstood some of the arguments they have received on this point, as Ofgem say *"It is fair to argue, as network companies have done, that a consistency adjustment could be made in either the de-gearing or re-gearing steps, hence explaining the different approach taken by Indepen compared with the SSMD"* (paragraph 3.42). Networks have not made such an argument.

[69] CEPA note the need for consistency between the approach taken to gearing in de-levering and the gearing used for re-levering. From this it follows that if Ofgem did wish to assume a MAR > 1 in the re-gearing stage, the cost of equity then calculated at the resulting notional market gearing would be the cost of equity for an amount of equity that is higher than the assumed equity RAV. It would then follow that in calculating the allowed return in the PCFM, consistency would require the calculated cost of equity to be multiplied by the corresponding market value of the notional equity, which would be greater than the equity RAV. This would increase overall allowed revenues compared to the standard approach, based on a calculated cost of equity at the notional RAV gearing multiplied by the notional equity RAV.

[70] "RIIO-2: Use of Market Evidence", CEPA, 9 July 2020, end of Section 5 on page 37, "*We consider that the logic and consistency arguments for adjusting the value of notional equity in the re-levering equation are, in principle at least, stronger than for making an equivalently-sized adjustment in the de-levering equation (we do not consider it appropriate to apply an adjustment on the de-levering step). However, for the various reasons outlined above, there are substantial regulatory process issues in the re-levering step as well that, in our view, would need to be considered and addressed before applying such an adjustment. Overall, we consider that evidence of observed MAR premia is more appropriate for consideration in Step 2 and 3 of Ofgem's cost of equity methodology.*"

- Our objection to the adjustment in the de-gearing step that was previously proposed by Ofgem is that it is fundamentally flawed, as, for example, Oxera previously explained *"raw equity betas are estimated by reference to outturn market returns, which are in turn affected by the companies' actual gearing levels. Therefore, to maintain internal consistency, the raw equity betas should be de-geared by reference to same actual gearing levels that underpin the observed share price movements. Ofgem's adjusted gearing approach produces a hybrid asset beta that reflects an assumed level of financial risk that is inconsistent with the actual level of market risk"*[71].

- In relation to making an alternative adjustment in the re-gearing step, as Frontier Economics[72] previously explained *"Indepen recommends to adjust the notional gearing level used in the re-gearing process by dividing by the EV to RAV ratio (i.e. MAR), such that the notional gearing used to re-gear is also based on EV. However, if Indepen's recommendation is to be adopted, Ofgem would then also have to use a weighting for equity of [1 - EV gearing] in the WACC calculation. In this way, EV would be used consistently through all steps"*. In this respect making an EV:RAV adjustment in the re-gearing step would appear to be largely equivalent to simply assuming a lower notional gearing under the traditional approach.

Step 1 gearing considerations, MVF Adjustment

The gearing value used to de-lever and re-lever raw equity betas can be calculated using net debt on either a market or book value basis. Regulatory precedent is to use figures on a book value in both steps, and as CEPA note in their report for Ofgem (and as Oxera previously explained), if the difference between book value and market value of debt was to be taken into account, this would need to be done in ***both*** the de-levering and re-levering steps, and ***not in just one step***. A simpler approach which gives effectively the same end result (i.e CAPM estimate of cost of equity) is to use book value of debt in both steps, consistent with regulatory precedent.

CEPA note[73] that:

- *"Market evidence should be preferred where possible as it is more consistent with principles of corporate finance theory and asset valuation.*

- *Where robust market values are not available and book values must be used as proxies it may be preferable to use book values throughout the calculation steps. The latter point is important to ensure we avoid inconsistency between the approach taken to gearing in de-levering and the gearing used for re-levering. .... The same principles that might cause the market value of actual company debt to deviate from its book value would also cause the market value of notional debt to deviate from its book value. This means that for consistency if we de-lever using a market value of debt, we should re-lever using an adjusted notional value of debt."*

Whilst market values of actual company debt may be observable, an adjusted or 'estimated market' value of the notional company's debt is not, and so it would need to be estimated. CEPA suggest that one possibility would be to estimate a market value for the notional debt based on the difference between the embedded rates used to calculate future cash flow allowances and the prevailing rates that reflect investors' prevailing discount rates for debt. However, additional assumptions would also be needed for such a calculation (for example regarding the assumed remaining life of the notional debt portfolio). In its consideration of this issue (at page 38 in the November 2019 update report), Oxera noted that *"the market value of*

[71] "The Cost of Equity for RIIO-2 Q4 2019 update", Oxera prepared for Energy Networks Association, 29 November 2019, page 33
[72] " Review of Ofgem's RIIO2 Beta Estimation: De-gearing and re-gearing of betas", Frontier Economics, 9 January 2020, page 8
[73] "RIIO-2: Use of Market Evidence", CEPA prepared for Ofgem, 9 July 2020, page 36

debt for the notional company will be higher than notional gearing multiplied by the RAV for the same reason that the market value of debt exceeds the book value of debt for comparator companies". This would suggest that it might be reasonable to assume that the ratio of market:book value for the notional company's debt was the same as that of the actual company (or group of comparator companies) – indeed, if the allowed cost of debt is being set appropriately for a notional debt book that matched the average debt book of the actual company (or comparator companies), this would seem a reasonable assumption.

In practice, using such an assumption, there is little effect on the final estimated notional equity beta if an adjustment is applied consistently to align debt to a market value basis in both the 'de-gearing' and 're-gearing' stages. There is therefore little point to changing the approach away from the use of book value of debt in both de-gearing and re-gearing steps, in line with regulatory precedent, and the traditional approach to treatment of debt in relation to de-gearing and re-gearing should be retained.

Implications of Ofgem's MVF adjustment

Ofgem does not take account of the market value of debt in the DD in the re-gearing step (i.e. when converting from asset beta to notional equity beta) and instead uses the book value of notional debt in this step. This is not in line with finance theory and CEPA's recommendation.

It therefore follows from the above discussion that the asset beta values that are used should similarly be based only on the estimates of asset beta that are calculated from observed raw equity beta and company gearing values that are calculated using the book value of debt only. However, Ofgem's estimates of asset beta for different listed companies and different estimation windows in Table 14 of the DD are presented on both a 'market value' and 'book value basis'. Half of the values in this table should therefore be ignored and removed from Table 14.

Ofgem's current approach to estimating an asset beta range for a pure-play energy network company appears to take the values in this table based on both market value and book value of debt into account (it is unclear otherwise why the additional values in Table 14 were included), but without then considering market value of debt when re-gearing (which would be in line with CEPA's recommendation to Ofgem). Even on Ofgem's stated approach therefore, which places most weight on the beta values of SVT and UU (paragraph 3.49), this will result in the estimated asset beta range and point beta values in the DD being too low, given the re-gearing method used by Ofgem. Correcting this error by removing this inconsistency alone would increase the overall estimated asset beta in the DD (both range and midpoint) by c.0.01[74], and so result in a cost of equity that is c.0.2% higher.

Ofgem's main criticism of companies' business plans and submissions and consultants' past reports in relation to these points is that there are gearing issues that are not resolved (see DD paras 3.43 and 3.54). However, this criticism is unjustified:

- Ofgem's first innovation (the EV:RAV adjustment), which appears now to have been dropped, was simply a technical error. Now this innovation has been dropped, consistent with our business plan and the advice from consultants, there are no "*inconsistent gearing issues*" associated with this.
- Our business plan (and Oxera's November 2019 report for the ENA) explained that Ofgem's second innovation (the MVF adjustment) does not result in unresolved gearing issues or significantly affect the resulting estimated notional cost of equity, provided it is applied correctly and consistently in both the de-gearing and re-gearing stages. For example, our business plan explained "*The gearing value used to de-lever raw betas can be calculated using net debt on a market or book value basis. Regulatory precedent uses*

[74] From the average differences between the asset beta values in Table 14 when calculated using market value of debt and book value of debt.

> *a view based on book value and in practice* ***we find there is little effect on the final estimated notional equity beta if an adjustment is applied consistently to align to a market value basis for both the 'de-gearing' and 're-gearing' stages. There is limited benefit therefore from changing approach and we choose to align to the approach based on regulatory precedent***".

One other issue to consider in relation to the de-levering and re-levering methodology applied in Step 1 concerns the debt beta value that should be used. This should use a value of 0.05, as shown by the evidence that is presented in our response to question FQ9 below.

Conclusion on how Ofgem should consider the gearing impact on beta in Step 1 of the methodology for estimating the cost of equity

- This should use the standard de-levering/re-levering approach, to de-lever from raw equity beta to an asset beta, and then re-lever the best estimate asset beta range and point values to a notional equity beta at the assumed notional gearing, so that the observed market beta values for different comparator companies can be compared and taken into account. In estimating the gearing values that should be used in the de-gearing and re-gearing steps, this uses:
  - Market values of equity when de-gearing and the assumed notional equity RAV when re-gearing, that is (1 - assumed notional gearing) x RAV, which is implicitly equal to the market value of the notional equity (but is also consistent with the equity value used in calculating the WACC; and with the £m amount of notional equity assumed in calculating allowed return in the PCFM).
  - Amounts of debt that are valued on a book value basis in both stages.
- Utilise a debt beta of 0.05, as justified by the Oxera reports on the subject

Step 2 gearing considerations

We turn next to consider the apparent narrow scope of this question FQ7 under Step 2, that is *"Do you have any views on how we should consider further the gearing impact on beta and cost of capital estimates?"*. Related to this, the DD also asks at paragraph 3.75, "*At this stage, we invite stakeholder views on how to consider this cross-check further in advance of Final Determinations. For example, we could put more weight on raw equity beta estimates for UU and PNN (see Table 11) such that the notional equity beta, as per Table 16, remains in line with most applicable market data. To supplement this, we could consider aligning notional gearing with observed gearing for the preferred comparators. Further, we invite analysis on whether there is an optimal level of notional gearing, which may accord with a view that the cost of capital is a U-shaped function*".

Ofgem erroneously calculates the WACC calculated at actual market gearing level cross check

In relation to Step 2, Ofgem's DD propose a new cross-check which seeks to eliminate the impact of gearing on cost of capital estimates first by calculating the WACC at the actual market gearing level of the various comparators (see Table 20), and then by calculating the required allowed return on equity to give the same WACC at the assumed notional gearing level (see Table 21). Ofgem find that under this approach the calculated cost of equity at 60% notional gearing is lower than when calculated using the standard de-levering/re-levering methodology at the conclusion of 'Step 1' at paragraph 3.55, i.e. 3.64% to 5.0% at 60% notional gearing. However, this result is largely attributable to the following factors:

- Reason 1: Ofgem incorrectly use a value for the cost of debt that is a weighted average of embedded and new debt.
- Reason 2: Ofgem's choice of CAPM parameters, in particular the value of RFR that is used.
- Reason 3: The particular sample lengths and averaging periods that Ofgem choose for the beta values that are used for this cross-check (5yr spot and 10yr spot, in each case based on market value of debt).

We consider each of these factors in turn.

Reason 1: Ofgem incorrectly uses a value for the cost of debt that is a weighted average of embedded and new debt

The DD recognise, quite rightly, that the overall remuneration of the cost of debt in the price control needs to take account of both embedded and new debt costs, where the interest rates on embedded debt are currently higher than the cost of new debt. However, as Ofgem explains at paragraph 3.71, this new cross-check relates to recent work by the CMA in relation to the NATS appeal and seeks to build on the work of Modigliani and Miller (M&M) which proposed that (under certain idealised circumstances) the cost of capital does not vary with gearing. In response the ENA explained in a recent submission to the CMA in relation to the PR19 appeals[75], that in applying this approach it is necessary to use the cost of new debt only, rather than to use a weighted average of new and embedded debt.

- It is not clear what the calculated WACC values in Table 20 of the DD represent. They assume the same weighted average cost of debt (calculated using the same proportions of new and embedded debt) at different gearing levels for the different comparators, rendering them non-comparable[76].
- If the WACC values in Table 20 were calculated using the cost of new debt only, they would at least be more comparable to each other, but they would not represent the WACC needed for an energy network under RIIO-2, as these WACC values would not then include the requisite additional revenues to compensate for the higher cost of efficiently incurred debt that had been raised during previous price controls (i.e. embedded debt).
- Therefore, it might be more useful to consider the values in Table 20, once corrected by being based on the cost of new debt only, as merely an intermediate step on the way to the values shown in Table 21.
- Once this change to use of the estimated cost of new debt only is made to the conversions at Tables 20 and 21, the impact of changes in gearing on WACC as you increase notional gearing from the past observed comparator gearing levels to a notional gearing of 60% are much reduced.

Reason 2: Ofgem's choice of CAPM parameters, in particular the value of RFR that is used

[75] ENA submission to the CMA in relation to the PR19 appeals process, 1/6/2020, paragraphs 2.2, 1.5 and Appendix 1: https://assets.publishing.service.gov.uk/media/5ed0f2b3d3bf7f45fb321450/Energy_Networks_Association_submission.pdf

[76] At a lower assumed future notional gearing level, the total amount of debt is lower, so the existing embedded debt would form a higher proportion of the total debt requred, and there would be a reduced need for new debt. Therefore, the proportion of new debt would be lower, leading to a higher weighted average cost of debt.

As the ENA's submission to the CMA then explained, the main reason for the remaining apparent sensitivity of the overall WACC to gearing is that the RFR that has been used by Ofgem in the cross-check in the CAPM is too low[77]. This not only leads to the apparent positive relationship between the WACC and gearing, but also leads to an underestimate of the cost of equity at all levels of gearing.

- The fundamental reason why the RFR used in this cross-check is erroneously low is that Ofgem has failed to uplift the yield on Index-Linked Gilts (ILGs) or deflated nominal gilts to account for the unique characteristics of sovereign bonds and the gap between corporate and sovereign risk-free financing rates.
- Paragraph 2.4 of the ENA's submission to the CMA explained the issue more fully *"To ENA's knowledge, the need for a detailed examination of whether the RFR has been underestimated has not arisen in any previous price controls. This is because the regulatory allowance for the RFR was set historically at a level above the spot yields on ILGs. However, by virtue of Ofwat (and the CMA in the NERL Provisional Findings) following the UKRN recommendation and setting risk-free rates based solely on spot yields of ILGs, an under-estimate of the actual risk-free rate that should be used in the CAPM framework has been revealed. This issue has been brought to ENA's attention by the CMA's concerns regarding the relationship between WACC and gearing expressed in the context of the NERL redetermination"*.
- Paragraph 2.7 notes that *"The evidence is summarised in Figure 1 below and points to an upward adjustment to the spot yield for ILGs of 50 to 100bps to determine the RFR for use in the CAPM. This adjustment should resolve the issue observed by the CMA that WACC apparently increases with gearing"*. This upward adjustment would increase Ofgem's value of the average RFR during RIIO-T2 from -1.48% (relative to CPIH) in the DD to between -0.98% and -0.48%. In their latest cost of equity update report Oxera[78] have again reviewed the evidence and shown that an upwards adjustment of c.0.75%[79] is needed to account for the special properties of gilts when estimating RFR. The reasoning is discussed more fully in paragraphs 2.7 to 2.12, and Appendix 1, of the ENA submission and in Section 2.1 of Oxera's latest cost of equity update report, which includes the following:
  - Fundamentally, the CAPM assumes that investors and firms can borrow and lend at the RFR. However, even with the best credit ratings, non-government investors cannot access debt at the spot rate of ILGs. The spot yields on ILGs therefore need to be adjusted for the unique features of ILGs, including a convenience ('money-like') premium attached to ILGs that pushes down government yields relative to the risk-free rate, by adjusting the rates for the gap between the corporate and sovereign risk-free financing rates.
  - Second, the RFRs assumed by sell-side analysts covering utilities in the UK are consistently higher than the spot yields on ILGs.

[77] This was also true of the RFR that was assumed by the CMA in its NATS Provisional Findings, when exploring the apparent relationship between gearing and cost of capital, as the ENA's submission explained in Section 2: https://assets.publishing.service.gov.uk/media/5ed0f2b3d3bf7f45fb321450/Energy_Networks_Association_submission.pdf

[78] "The cost of equity for RIIO-2 Q3 2020 Update", Oxera prepared for the Energy Networks Association, September 2020, section 2.1

[79] Compared to the average projected RFR based directly on index-linked gilt yields in the DD of -1.48%, Oxera estimated a corresponding average (see page 14, for the 6-month figure for RFR which starts from approximately the same ILG yield as Ofgem's Draft Determinations) across the years of RIIO-2 when taking account of these features that was -0.79%; and see also the 'adjustment' in Table 2.5

When combined with the use of new debt only, use of a higher RFR, that allows for the unique features of ILGs by adjusting the rates for the gap between the corporate and sovereign risk-free financing rates, substantively eliminates the positive relationship between WACC and gearing that Ofgem notes in paragraph 3.71, and so renders Ofgem's proposed cross-check, as illustrated by Tables 20 and 21, superfluous.

The impact of correcting the RFR and cost of debt parameters used in this cross-check can be illustrated by reproducing Ofgem's Table 20, using Ofgem's values for TMR, debt beta, raw equity beta and comparators' company gearing from Tables 13 and 14, but using:

- RFR of -0.73%, which represents the result of increasing Ofgem's -1.48% DD value found from ILGs by the estimated uplift of 0.75% found in Oxera's work; and
- The cost of new debt only, using a value of 0.4%, which seems to be the average value assumed by Ofgem in the DD (excluding the allowance for additional borrowing costs).

With these inputs, the weighted averages of the cost of equity and cost of new debt at actual gearing, which would be WACC values for a company which had raised no debt in the past but was instead able to raise all its debt on the day preceding the price control, are as follows:

Table 5: Equivalent results to Ofgem's Table 20 'WACC inference at observed gearing levels', if calculated using Ofgem's parameters, except for use of a RFR equal to -0.73% and use of the cost of new debt only

Estimation Window	Averaging period	Value of debt	SSE	NG	PNN	SVT	UU
5 year	Spot	Market value	4.2%	2.2%	2.2%	1.8%	1.8%
10 year	Spot	Market value	3.5%	2.0%	2.1%	1.7%	1.7%

Based on the above table, the inferred cost of equity at 60% notional gearing based on Ofgem's "flat WACC" hypothesis are as follows (even when using Ofgem's parameters other than a RFR of -0.73% instead of -1.48% and cost of new debt only):

Table 6 Inferred cost of equity at 60% gearing based on Ofgem's "flat WACC" hypothesis using -0.73% RFR and cost of new debt only

Estimation Window	Averaging period	Value of debt	SSE	NG	PNN	SVT	UU
5 year	Spot	Book value[80]	9.8%	4.9%	4.8%	3.8%	3.8%
10 year	Spot	Book value[81]	8.1%	4.5%	4.6%	3.7%	3.6%

These values can be compared to the cost of equity that would be calculated at 60% notional gearing under the standard de-levering / re-levering approach (for RFR of -0.73%) where, for

[80] We note that Ofgem's Table 21 says Market value in this column, but this appears to be incorrect – the values seem to be calculated using a notional book value gearing of 60%, and do not make any adjustment between book value and market value for the notional debt, even though the allowed cost of debt of 1.74% assumed by Ofgem is much higher than the current or projected spot rates of c.0.4%.

[81] As per previous footnote

comparability with the above results, we retain the error caused by the inconsistency between observed gearing on a market value basis and notional gearing on a book value basis.

Table 7 Derivation of notional cost of equity at 60% notional gearing under the standard de-levering/relevering approach, for comparison to the values in Table 6 above that were based on Ofgem's 'flat-WACC' approach

Estimation Window	Parameter	SSE	NG	PNN	SVT	UU
5 year Spot	Market Value gearing – see Ofgem Table 13	36%	47%	44%	57%	58%
	Raw Equity beta – see Ofgem table 11	0.97	0.63	0.59	0.59	0.61
	Asset beta (for debt beta of 0.125)	0.67	0.39	0.39	0.32	0.33
	Re-geared equity beta at 60% notional gearing (book value basis)	1.48	0.79	0.78	0.62	0.63
	Cost of equity at 60% notional (book) gearing	**10.0%**	**5.0%**	**4.9%**	**3.8%**	**3.9%**
10 year spot	Market Value gearing – see Ofgem Table 13	33%	48%	43%	56%	57%
	Raw Equity beta – see Ofgem table 11	0.79	0.59	0.56	0.57	0.57
	Asset beta (for debt beta of 0.125)	0.57	0.37	0.37	0.32	0.32
	Re-geared equity beta at 60% notional gearing (book value basis)	1.24	0.73	0.74	0.61	0.60
	Cost of equity at 60% notional (book) gearing	**8.2%**	**4.5%**	**4.7%**	**3.7%**	**3.6%**

Again, the figures in these tables are obtained using Ofgem's choice of parameter values except for RFR, and should not be taken to imply that we agree with these values. We do not agree with these values, as explained more fully in our response to question FQ9 below.

It can be seen that in each case, once the conversions between different gearing levels use the cost of new debt only, and a risk free rate that allows for the unique features of ILGs (by adjusting the rates for the gap between the corporate and sovereign risk-free financing rates), the calculated cost of equity at 60% notional gearing under Ofgem's new 'constant WACC' cross-check are almost identical to those that are calculated using the traditional de-levering/re-levering approach.

Reason 3: The particular sample lengths and averaging periods that Ofgem choose for the beta values

A third reason why cost of equity values in Ofgem's Table 21 are lower than those proposed at Step 1 of Ofgem's cost of equity methodology (3.64% to 5.0% at 60%, see paragraph 3.55) is that Ofgem has chosen to apply the cross-check using beta values for sample parameters that give amongst the lowest asset beta values in the DD Table 14, rather than beta values that better represent the spread of values in Table 14.

A further, related reason is that, as explained earlier in this answer to question FQ7 above, because the cost of equity in Ofgem's Table 21 is calculated for a notional gearing of 60% based on notional book value of debt, consistency requires that the actual past gearing values used alongside the observed raw equity beta for the comparators as the starting point for these calculations (whether under Ofgem's 'constant WACC' approach or the standard de-levering/re-levering approach) should also be on a book value basis. If Ofgem had instead used book value gearing in deriving the values in Table 20, the values in Table 20 would have been higher, leading to correspondingly higher values in Table 21 also.

Table 8 below shows the cost of equity at 60% notional gearing if derived using Ofgem's 'constant WACC' cross-check and when using the conventional de-levering / re-levering approach which follows regulatory precedent, once the various errors described above have been corrected. In each case the values in this table are still based on the parameters proposed by Ofgem in the DD (debt beta of 0.125; TMR of 6.5%), except for i) use of the cost of new debt only, and (ii) use of a RFR of -0.73% (to correct for the unique characteristics of sovereign bonds and the gap between corporate and sovereign risk-free financing rates as explained above). The values are calculated using each of the raw equity beta values and book value gearing figures shown in Ofgem's Tables 11 and 13. Table 8 shows that in each case the cross-check, if applied properly, gives results that are very close to those under the standard de-gearing/re-gearing methodology.

It should, though, again be noted that we do not agree with Ofgem's proposed parameter values for debt beta, TMR and asset beta as well as for RFR, as explained in our response to questions FQ5 and FQ6 above and FQ9 below. We therefore consider that the available evidence supports a materially higher cost of equity for a regulated UK transmission network company than might be implied from the Table 8.

Table 8 Comparison of cost of equity at 60% notional gearing under 'constant WACC' cross-check and when using the conventional de-levering / re-levering approach (-calculated using Ofgem's book value gearing and raw equity beta values for National Grid, Ofgem's c.0.4% cost of new debt, and Ofgem's CAPM parameters except for use of RFR = -0.73%)

Estimation Window	Averaging period	Average Book Value Gearing (estimates based on Ofgem's Table 13)	Cost of Equity at 60% notional based on Ofgem's 'constant WACC' cross-check	Cost of equity at 60% notional gearing – based on standard de-gearing / regearing approach
2-year	Spot	48%	4.85%	4.92%
2-year	2-Year	c.46%	5.02%	5.10%
2-year	5-year	c.44%	5.30%	5.39%
2-year	10-year	c.45%	4.61%	4.70%
5-year	Spot	44%	5.19%	5.29%
5-year	2-Year	c.44	5.30%	5.39%

5-year	5-year	c.44%	4.99%	5.08%
5-year	10-year	c.45%	4.81%	4.90%
10-year	Spot	45%	4.71%	4.80%
10-year	2-Year	c.45%	4.51%	4.60%
10-year	5-year	c.45%	4.81%	4.90%
10-year	10-year	c.45%	4.81%	4.90%

In conclusion, Ofgem should simply convert the observed market value of beta and gearing (based on book debt and market value of equity) to an asset beta, and then re-gear this to an equity beta at the chosen notional gearing (60%) using the standard delevering/re-levering approach. This equity beta can then be applied in the CAPM formula to give the allowed cost of equity.

Additional questions at paragraph 3.75:

In relation to Ofgem's additional questions at paragraph 3.75:

- "*At this stage, we invite stakeholder views on how to consider this cross-check further in advance of Final Determinations*"

  As illustrated above, once a better justified value of RFR is used, and the cost of new debt only is used when converting between different gearing levels (instead of a weighted average of new and embedded debt, which was erroneously based on a constant ratio of new:embedded), the cross-check gives substantively the same cost of equity at any assumed notional gearing level as under the traditional de-levering/re-levering approach. It appears that this cross-check therefore does not add anything.

  - *"For example, we could put more weight on raw equity beta estimates for UU and PNN (see Table 11) such that the notional equity beta, as per Table 16, remains in line with most applicable market data"*

  We assume here that Ofgem intended to refer to UU and SVT, as PNN has had market gearing that is substantially lower (Ofgem's Table 13 suggests a gearing of around 45%). Even then, we do not agree with this suggestion. As explained in our response to question FQ5, the available evidence demonstrates that asset beta values for energy network companies are higher than for water companies. It would therefore be inappropriate to place additional weight on raw beta estimates for water companies. Instead, more reliance should be placed on the asset beta of National Grid, which Ofgem's own data (see Table 14) shows has been consistently higher even at Group level (i.e. for National Grid plc) than that of the water companies, with an additional adjustment then needed to allow for the market evidence which demonstrates a higher equity beta for National Grid's UK networks than for its US businesses.

- *"To supplement this, we could consider aligning notional gearing with observed gearing for the preferred comparators"*

  This option could be pursued, but there would seem little benefit for consumers. Firstly, the WACC at the different gearing levels would be virtually the same (as the cross-check, once applied properly, gives the same cost of equity and thus eventual WACC as the standard de-levering/re-levering approach). Secondly, a larger reduction in notional gearing would require a larger allowance for the cost of raising new equity on both a notional and actual basis. Paragraphs 5.22 and 11.46 in the DD explain that even a reduction from 60% to 55% notional gearing incurs an assumed transaction cost equal to 0.25% of RAV, so a larger reduction from 62½% to 45% notional gearing would result in an allowance equal to 0.875% of RAV, or >£50m for NGGT alone, without any associated benefit for consumers through a reduction in the WACC. Thirdly, a larger reduction in notional gearing from the previous price control level would implicitly require an assumption that a corresponding amount of existing embedded debt would need to be cancelled 'early', effectively at the start of the next price control. Network company bonds, like bonds in other industry sectors, currently have a market value that is typically somewhat higher than their face value. Consequently, a buy-back of 17½% of existing embedded debt would incur a significant up-front cost (for example, if debt had a market value premium above face value of 30% say, the cost would be c.17½% x 30% x RAV = 5¼% of RAV, so >.£300m for NGGT alone) even before any additional 'early redemption premium' is taken into account, and this would need to be funded in the first year of the price control through additional charges to consumers. Whilst this additional cost would gradually be recovered through lower cost of debt allowances (and thus network charges) in subsequent years, it would take many years (probably 15 to 20) before all the cost would be recovered, and it seems unlikely that the additional substantial costs in the first year would be acceptable to customers or consumers.

- *"Further, we invite analysis on whether there is an optimal level of notional gearing, which may accord with a view that the cost of capital is a U-shaped function"*

  Once appropriate inputs are used when calculating the cost of equity using CAPM and in assessing the variability of WACC with gearing, it is found that the WACC is not very sensitive to gearing. There are benefits in terms of predictability if a reasonable degree of consistency is maintained in the assumed notional gearing level from one price control to the next where possible. Some modest changes may sometimes be justified though, where these are made in response to changing circumstances, for example the proposed relatively minor reduction from 60% to 55% for transmission networks in RIIO-T2 to help address financeability concerns.

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

We do not agree with Ofgem's interpretation of cross-checks as all of the cross-checks either contain errors in their application or are of limited or no relevance. Consequently, they should not be used to justify such a reduction to the best estimate of cost of equity that is calculated under 'Step 1' using the CAPM. These are summarised in the table below with further detail provided in Appendix 1 to this annex.

Table 9: Summary of our views on Ofgem's proposed cross checks to cost of equity

Cross Check of the Cost of Equity proposed by Ofgem	National Grid's view of the cross check (the CPIH-real cost of equity it gives; and/or comments on the relevance of the cross-check)
Modigliani-Miller cost of equity inference (WACC cross-check)	Once the cross-check is carried out properly, and appropriate parameters for the different input parameters are used, the calculated WACC is almost insensitive to the gearing level, so this cross-check simply gives a result that is consistent with the CAPM estimate. Whilst there may be different values for different comparator companies and for different sample lengths etc, these variations are equally apparent and are better assessed in the analysis of the asset beta (and corresponding notional equity beta) levels for different comparators. They have therefore already been taken into account in forming a view of the CAPM parameters, which should be based on all the available evidence taking account of the relevant company characteristics, rather than just a small number of selected data points, which is what this cross-check would do. Weight should therefore not be placed on this cross-check.

MAR-implied cost of equity	MAR analysis depends on many assumptions and as a result is unable to give a clear indication of investors' return requirements or expectations. The observed MAR values can be explained without a need to assume that investors are being overcompensated.
Unadjusted OFTO implied equity IRR	OFTO projects have different (and lower) risk profiles than those of UK energy networks, so the OFTO implied IRR does not provide a meaningful cross-check.
Unadjusted investment managers (TMR) cost of equity	We do not support attaching significant weight to these views. However, even Ofgem's values of investment manager views of TMR are somewhat higher than the cost of equity proposed in draft determinations.
CAPM with 0.9 equity beta & investment managers' TMR	Investment managers views of TMR would be more relevant as a check of TMR than of the estimated cost of equity reached in Step 1 using the CAPM (though we still do not support attaching significant weight to them). Once likely conservatism in these values is considered; an upward adjustment is made to correctly allow for geometric averaging; inconsistencies in two of the data points referred to by Ofgem are removed; and the implications of the much higher values shown by the small number of more recent manager's TMR values are considered, the Investment Manager views of TMR would support use of much higher values of TMR than Ofgem assumed in the Draft Determinations.
Unadjusted infrastructure fund implied equity IRR	Infrastructure funds have different (and lower) risk profiles than those of UK energy firms, so (like OFTO returns) the infrastructure fund implied IRR does not provide a meaningful cross-check. Ofgem's calculations of infrastructure fund discount rates also rely on an assumption that any premium above NAV means that the fund is overestimating its own cost of capital, but as with MAR analysis) there are multiple explanations for market valuations that do not rely on the overestimation of cost of capital.

We provide more detailed comments in relation to the use of each of these cross-checks in Appendix 1, and below we draw attention to a more meaningful cross-check than those proposed by Ofgem.

A more meaningful cross-check – Asset risk premium to Debt risk premium differential

Our business plan describes a cross-check which is less subjective and more informative that those proposed by Ofgem, which is based on the required Asset Risk Premium to Debt Risk Premium (ARP to DRP) differential. As Oxera have explained in greater detail[82], this is a cross-check that can be applied to the cost of equity that draws on evidence from debt markets to ensure that the allowed returns set by the regulator for equity are commensurate with the risk associated with operating and owning the associated assets.

This test is related to the required differential between the asset risk premium and debt risk premium[83]. On this basis, Oxera's latest analysis using this cross-check in their September

[82] "Review of RIIO-2 finance issues: Asset risk premium, debt risk premium and debt betas", Oxera prepared for Energy Networks Assocation, March 2019; "The cost of equity for RIIO-2, Q4 2019 update", Oxera prepared for Energy Networks Association, 29 November 2019 – Section 5.2; and "Asset risk premium relative to debt risk premium", Oxera prepared for Energy Networks Association, September 2020

[83] The asset risk premium is the additional compensation over the RFR that investors require to invest in a company as a whole. This is the premium for equity risk assuming zero gearing and should be higher than the risk premium on debt given the lower priority of equity relative to debt in terms of claims on cash flows.

2020 report[84] shows that Oxera's latest estimated cost of equity range (6.00% to 7.08% relative to CPIH at 60% notional gearing) is in line with recent market evidence, unlike Ofgem's DD value for the cost of equity (4.20% even before Ofgem's proposed 'Step 3' deduction of the ER-AR wedge). This is because Oxera's range implied a differential between the asset and debt risk premium that falls across the middle of the empirically observed distribution of the ARP–DRP differential observed for the bonds issued by UK utilities (ranging from the 24th to 58th percentiles), whereas Ofgem's value would give a differential that lies at a very low percentile of the observed distribution of ARP-DRP values, and so is not in line with this recent market evidence[85].

Ofgem considered this cross-check in the SSMD and acknowledged *"the principle set out by Oxera and note that the ARP calculated by Oxera is higher than the DRP"*. However, Ofgem suggested *"that Oxera's argument does not focus on the absolute difference"* and expressed several reservations with the approach (SSMD pages 124 to 126). In response, Oxera have now written a new report[86] which:

- addresses Ofgem's concerns set out in the RIIO-2 SSMD, and reveals more information to support the conclusion that Ofgem's RIIO-2 cost of equity allowances in the Draft Determination falls below that suggested by contemporaneous market evidence
- finds that the ARP−DRP differentials implied by past regulatory allowances in energy were broadly in line with those implied by the market evidence around the time of the determinations.
- provides new evidence explaining why the ARP−DRP framework merits greater weight than the cross-checks for the allowed cost of equity considered by Ofgem;
- highlights the benefits of using this approach for the assessment of financeability across sectors and over time;
- describes how the ARP−DRP framework can be used to obtain conservative estimates of the WACC that are in line with contemporaneous market evidence;
- updates the analysis presented in the earlier Oxera ARP−DRP report[87] to reflect the revised approach to the risk-free rate presented in recent Oxera work presented to the CMA as part of the PR19 appeal;
- responds to Ofgem's comments on Oxera's asset risk premium report in its RIIO-2 SSMD. For example, in response to Ofgem's concern that the analysis presumes a constant ARP−DRP, this report shows the ARP−DRP differentials of UK utilities comparators over time.

The conclusion of this updated work is that this cross-check supports Oxera's updated cost of equity range for RIIO-2 from 6.00% to 7.08% (CPIH real) at 60% notional gearing[88], because the ARP−DRP differential implied by Oxera's recommended cost of equity range is broadly in line with recent market evidence. In contrast the analysis shows that Ofgem's DD mid-point cost of equity (4.2%) would need to be increased by 2.15% to bring its implied the ARP−DRP differential up to the median derived from contemporaneous market data - though because of the attenuation bias in the benchmarks, this is a conservative estimate of the size of the

[84] "Asset risk premium relative to debt risk premium", Oxera prepared for the Energy Networks Association, September 2020
[85] Ibid., Table 1.1 and the final paragraph on page 5
[86] Ibid.,
[87] "Review of RIIO-2 finance issues: Asset risk premium, debt risk premium and debt betas", Oxera prepared for Energy Networks Association, March 2019
[88] "The Cost of Equity for RIIO-2 Q3 2020 Update", Oxera prepared for the Energy Networks Association, September 2020, Table 1.1

increase required to place the cost of equity proposed in DD in line with contemporaneous market benchmarks[89].

Thus, this ARP-DRP cross-check continues to support a cost of equity that is considerably higher than that proposed by Ofgem in the DD.

Conclusion on cross-checks:

As the evidence above sets out, the conclusions from cross checks are:

- the cross checks used by Ofgem are not comparable benchmarks to apply to five-year energy network allowed return and/or are imprecise or transient in nature so give us only limited information.
- even once corrected, Ofgem's cross checks do not support the allowed equity return that is proposed in the DD; and
- the ARP vs DRP differential is a better, more meaningful cross check, which shows that the DD allowed equity return is too low.

Step-3 allowed return on equity consultation questions

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

We do not agree with the assessment of allowed returns. A return of 3.95% is too low compared to UK and risk adjusted international comparators, owing mainly to a beta which incorrectly assumes the water and energy sectors are the same risk, incorrectly estimated values for total market return and risk-free rate, and the inclusion of a flawed outperformance wedge.

Our main issues with the assessment are:

1. Ofgem's methodology for estimating TMR is in error as it fails to take account of the full evidence available, and so results in significantly underestimated value of TMR.
2. Academic theory supports the use of a risk-free rate in the CAPM that is higher than the spot yields on ILGs.
3. The notional equity beta is too low due to Ofgem's overestimate of debt beta and underestimate of the asset beta.
4. Ofgem's cross-checks are not comparable benchmarks to apply to five-year energy network allowed returns and / or are imprecise or transient in nature; and better justified cross-checks support a cost of equity that is much higher than Ofgem propose in the DD.
5. The conceptually and practically flawed outperformance wedge will lead to increased costs for consumers.

Items 1, 2 and 5 are expanded on below. Evidence for a lower debt beta referenced in 3 is also set out below, with evidence on asset beta covered in response to FQ5. A summary of our views on item 4 is covered below and are expanded on in more detail in our response to FQ8 (cross checks) and Appendix 1.

At a summary level, the remedies required for Final Determinations are:

- when setting TMR, use RPI rather than an unreliable back cast of CPI inflation, more balanced TMR data sources and adopt a figure that is at least as high as the historic

[89] "Asset risk premium relative to debt risk premium", Oxera prepared for the Energy Networks Association, September 2020, page 21

arithmetic average. We do however recognise that the CMA are currently reviewing TMR evidence in the context of appeals of PR19;

- increase RFR estimates by c.75bps above that of gilt yields, to take account of the unique features of government bonds;
- Ofgem should heed their own data and accept that energy network risk is higher than water networks and set an asset beta at least as high as that of NG plc over the last five years, although a higher value than this seems better justified when the range of available evidence is taken into account;
- remove invalid cross checks, including the MAR cross checks that compound the errors made in assessing asset beta, and instead take note of the more meaningful cross check based on ARP vs DRP; and
- remove the flawed outperformance wedge.

Ultimately, a balanced assessment of the allowed equity return will show that 3.95% based on a notional gearing of 60% is far too low for the risk of a transmission company.

Ofgem's approach to setting the cost of equity for RIIO-T2 involves a 3-step process:

- Step 1 is to review the Capital Asset Pricing Model evidence – the DD reached a value of 4.3% at 60% gearing under step 1;
- Step 2 is to cross-check the CAPM-implied cost of equity against other approaches or indications of the cost of equity – the DD reduced the Step 1 value by a small amount, to 4.2%, based on Ofgem's view of cross-checks;
- Step 3 is to apply a deduction to the estimated cost of equity arrived at through Steps 1 and 2 to give the allowed return on equity – at 60% gearing. Ofgem propose a deduction of 0.25%, leading to the final allowed cost of equity value of 3.95% (at 60% gearing) that was proposed in the DD.

Ofgem's application of these 3 Steps in the DD results in an allowed cost of equity that is substantially too low.

We do not agree with the proposed Step 3 deduction, as explained more fully below and in our response to question FQ10. The ER-AR deduction is not justified and is conceptually and practically flawed. Notably no consultant's report has ever supported this adjustment.

Our thoughts on Ofgem's proposed cross-checks under Step 2, and support for other alternative cross-checks which are better founded, were set out above in our response to FQ8 (and in Appendix 1). However, Steps 2 and 3 both involve making adjustments to the initial main estimate of the cost of equity that is first established using the CAPM under Step 1. In order to assess whether Ofgem's proposed allowed return on equity of 3.95% at 60% notional gearing is reasonable, it is therefore of overriding importance first to consider whether the available CAPM evidence does actually lead to a best estimate of the cost of equity of 4.3% (real relative to CPIH). A proper assessment of the available evidence shows that this is not the case, and a figure of 4.3% is much too low.

Step 1

The CAPM calculates a value for the cost of equity from values for three parameters: Risk Free Rate (RFR), Total Market Return[90] (TMR) and an equity beta (which depends on the assumed

[90] The cost of equity can alternatively be calculated using the CAPM from β, the Risk Free Rate and the Equity Risk Premium (ERP = TMR – RFR), where the ERP is estimated directly instead of the TMR. However, most GB regulators, as well as the Competition and Markets Authority (CMA) prefer to use the formulation which

notional gearing). These parameters are combined using the following formula to estimate the cost of equity (CoE):

$$CoE = RFR + \beta \cdot (TMR - RFR)$$

The values that Ofgem has used for all three of these parameters appear too low, as we explain in the following paragraphs.

***Total Market Return:* Ofgem's methodology for estimating TMR is in error as it fails to take account of the full evidence available, and so results in significantly underestimated value of TMR**

Throughout the development of RIIO-2, Ofgem has received extensive evidence from networks and in consultants' reports which show that Ofgem's estimated range for TMR (6.25% to 6.75% relative to CPIH) is too low. This evidence is not all repeated here, but we refer Ofgem back to these earlier submissions and consider these to be part of this response. For example, we draw Ofgem's attention to the following:

- National Grid Gas and National Grid Electricity Transmission's response to the RIIO-2 Framework Consultation Response, 2 May 2018, and especially the response to question 35 and Appendix 2
- NERA's report "Review of UKRN recommendations on the appropriate inflation index for estimating historical TMR", prepared for National Grid, 1 May 2018, attached as Appendix 5 to National Grid's RIIO-2 Framework Methodology consultation response.
- National Grid's response to Ofgem's RIIO-2 sector-specific methodology consultation – Finance, March 2019, and especially the response to questions FQ9 to FQ11.
- NERA's report "Further evidence on the TMR", Prepared for Energy Networks Association (ENA), 20 November 2018
- Oxera report "The cost of equity for RIIO-2 - A review of the evidence", prepared for Energy Networks Association, 28 February 2018
- Oxera report "The cost of equity for RIIO-2 - Q4 2019 update", prepared for Energy Networks Association, November 2019
- Frontier Economics report "Inflation in the context of real TMR", a note for the ENA prepared by Phil Burns, supported by Mike Huggins, Rob Francis and Michael Yang, 13 March 2019
- National Grid's report "Total Market Return: The consistency of long-run CPI and RPI inflation series in the UK, and their relative suitability for use in calculating the actual historic long-run average equity market return in the UK on a 'real' basis", 23 January 2020

uses TMR rather than ERP because it gives more stable estimates, and this is the approach which Ofgem have proposed for RIIO-2. We agree that this approach is more reliable.

In addition, Oxera have now prepared a new cost of equity update report for the ENA. In this new report Oxera consider TMR and we refer Ofgem to this[91].

The value of TMR that has been used by Ofgem in the DD, consistent with the SSMD from May 2019, is from 6.25% to 6.75% (relative to CPIH). In simple terms, this range has principally been estimated from data on the long-term historical average realised (ex-post) market return. If based on an average across a sufficiently long time-frame, this average realised return is widely considered the best and most objective estimate of investors' expectations of the future level of market return. It assumes that the use of realised average returns from historic data provides an unbiased estimate of the expected market return over long time periods.

Whilst we agree with Ofgem that interpretation of long-run average returns should form a key part of the proposed methodology for setting TMR, applying this approach requires a series of decisions and is dependent on:

- the inflation measure used to deflate the actual return in each past year, which is on a nominal basis, to give the 'real' return in that year;
- the averaging approach used to derive an average value of historic return that can be used as a value of TMR in the CAPM. This issue relates to the difference between arithmetic and geometric average, in the context of compounding and discounting future cash flows;
- the timeframe across which the average returns are calculated, and in particular the start date of the period considered;
- whether an adjustment needs to be made to the calculated averages to recognise that for the first part of the dataset of returns data that is being used by Ofgem, the returns relate only to the largest 100 companies rather than all UK equities.

Ofgem estimates the TMR portion of allowed equity return using a back-cast of CPI inflation which the authors of the data set and the ONS consider to be unreliable. In addition, within the estimation, Ofgem has relied on historical TMR data sources which are artificially reduced and also fail to recognise the negative impact on investment decisions from not using a figure at least as high as the historical arithmetic average. As a result, Ofgem's proposed figure is over 100bps below the regulatory precedent on a like for like basis and in effect undermines the value neutrality of the transition from Retail Price Index (RPI) to Consumer Prices Index including owner occupiers' housing costs (CPIH) indexation.

Ofgem's range and point estimate are broadly in line with those of Ofwat in the PR19 price control Final Determinations. The material errors outlined above are currently being appealed to the Competition and Markets Authority (CMA) by four water companies and we have submitted supporting evidence as part of the Energy Networks Association (ENA) third party response. There are other elements of the RIIO-2 financial framework that are also in scope of the CMA appeal such as the approach to measuring the RFR, the long-standing principle of aiming up within the cost of equity range in order to minimise potential social welfare impacts, and the approach to setting debt beta. If the CMA findings were to agree with the water companies in any of these areas, then it would have an upwards impact on Ofgem's proposals in the DD.

These TMR issues are considered further in appendix 2 to this finance annex under the following issues we have with Ofgem's approach:

- TMR Issue 1: The CPI back-cast used to deflate the actual return is considered unreliable by its authors and the ONS;
- TMR Issue 2: TMR should use a discount rate at least as high as the historical arithmetic average to reflect investors' discount rate approach for capital budgeting

[91] "The cost of equity for RIIO-2 Q3 2020 update", Oxera prepared for the Energy Networks Association, September 2020, Section 2

- TMR Issue 3 – the averaging period used by Ofgem gives the lowest TMR results;
- TMR Issue 4 – Ofgem's estimate is not based on return across the whole equity market from 1899 to 1954.

Conclusion on Total Market Return estimates from Long-Run Average Returns

Our conclusion is that, in each case, Ofgem adopts the approach that leads to a lower or the lowest value of TMR. In combination, as a result of these issues, Ofgem very significantly underestimates the TMR and as a result the cost of equity. Ofgem's DD fails to provide any real counterpoints to these methodological errors and identified biases, and in the absence of such arguments must take these issues into account when estimating the TMR from long-run average returns for the RIIO-T2 FD.

TMR Cross-checks

In the SSMD, Ofgem proposed that TMR estimates from long-run average market returns should be cross-checked to other estimates of TMR, mainly to results from DDM models, but also noting investment manager forecasts (considered in the response to FQ8 above). In contrast, in the DD Ofgem does not refer to TMR cross checks under Step 1, although in Appendix 3 Ofgem say in relation to Oxera's 2019 report "*Updated evidence from surveys and DDMs suggest an increase in the TMR since the previous Oxera report. We place limited weight on these measures given the subjectivity involved. Oxera's place significant weight on DDM without reconciling why its assumptions are better than those used in CEPA's DDM/DGM, as displayed at SSMC*". In response we draw Ofgem's attention to:

- pages 29 to 31 of our response to the Finance questions in the Sector Specific methodology consultation, where we did explain the concerns with CEPA's model and the assumptions it used; and
- Section 2.2.2 (page 19 to 21) in Oxera's November 2019 update report, which provided an update (as at end August 2019) of Oxera's DDM model which uses the same approach as the Bank of England's, and (on page 21) commented on Ofgem's/CEPA's DDM model and showed it had clear deficiencies, for example "*We note that the DDM model used by Ofgem in the SSMD has a different specification to that used by the Bank of England, as the specification used by Ofgem uses only long term growth forecasts for the UK. However, in 2018, companies in the FTSE All-Share Index generated only 20% of revenues in the UK, with the rest coming from international activities. As such, we believe this specification to be incorrect, as it does not seem reasonable to assume that earnings generated outside the UK will grow at the same rate as the GDP of the UK. Given that international markets in which the FTSE All-Share companies operate have, on average, higher GDP growth rates than the UK, the specification used in the SSMD would be a downward-biased estimate of the true DDM-implied equity market discount rate.*"

Whilst only being seen as a cross-check, these references show that Oxera's model is better justified than CEPA's, as well as being more up-to-date. In the November 2019 report, Oxera's updated evidence from DDMs indicates an increase in the implied equity market discount rate since the 2018 Oxera report, regardless of how these models are specified, with the results from the specification used by the Bank of England indicating a CPIH-real equity market discount rate of 9.5%. Perhaps more important though, the Oxera 2019 report's updated estimates of the equity market discount rate implied by a DDM based on the Bank of England methodology remained in line with averages over the past ten and fifteen years, suggesting that there has been no decrease in the expected TMR over this period. This is in stark contrast to Ofgem's proposed TMR for RIIO-T2, which is reduced from 7.25% relative to RPI in RIIO-T1 to a proposed value of 6.5% relative to CPI, i.e. a like-for-like reduction of between 1.6% and 1.8%.

Finally, as noted in our response to question FQ8 (and Appendix 1), investment manager forecasts would be better seen as a cross-check of TMR rather than of the final CAPM estimate of cost of equity. Although we would not advocate putting significant weight on these forecasts, the response to FQ8 supported by Appendix 1 also points out that in the light of the significant impact of the Covid-19 outbreak, the investment manager forecasts from 2018 and 2019 that were referred to by Ofgem in the DD can no longer be considered relevant as an indication of investment managers current views[92], and the small number of forecasts from Ofgem's group of investment managers that have been published in recent months have pointed to significantly higher TMR values than previously.

Risk-free rate: Academic theory supports the use of a risk-free rate in the CAPM that is higher than the spot yields on ILGs

We do not agree with Ofgem's use of spot yields of Index Linked Gilts (ILGs) to set the RFR, which causes them to under-estimate of the actual risk-free rate by c.0.75% per annum.

In the SSMD[93], Ofgem decided to:

- *"implement equity indexation by updating the allowed return on equity to reflect changes in the risk-free rate only, referring to data prior to the financial year beginning, and to long-horizon inflation forecasts (t+5 from OBR).*
- *re-consider the exact calibration of how this is done, including the method for deriving CPIH (or CPI) real values, the averaging period and the relevant tenor. We will propose an updated approach at Draft Determinations".*

The DD confirm that Ofgem intends to adopt this approach, whilst additionally retaining "*some discretion during RIIO-2 to refine the calculation in light of difficulties estimating CPIH-real gilts using market data, as reflected in a recent HM Treasury consultation*"[94].

Our concerns over the practical difficulties and associated risks for networks of implementing this approach are given in our responses to questions FQ4 and FQ21. In this section of our response, we focus instead on the broader issue of whether an estimate of the RFR that is calculated from sovereign gilts without adjustment as under the proposed method is an appropriate estimate of the RFR for use in the CAPM when estimating a company's cost of equity.

This is an issue that has described and considered by Oxera in a report written for the ENA[95] that was submitted by the ENA in relation to the PR19 appeals by 4 water companies, and Oxera have now updated this assessment in their latest cost of equity update for the ENA[96]. Basing the RFR directly on gilt rates is an error as it gives a value for the RFR that is too low, unless it is increased to account for the unique characteristics of sovereign bonds and the gap between corporate and sovereign risk-free financing rates.

The need for a detailed examination of whether the RFR has been underestimated has not arisen in previous rounds of price controls prior to 2019, because the regulatory allowance for the RFR in different sectors was set historically at a level above the spot yields on ILGs. However, because Ofgem in RIIO-2 (like Ofwat in PR19, and CAA in the NATS price control) now intend to set risk-free rates directly from the spot yields of ILGs, an under-estimate of the actual risk-free rate that should be used in the CAPM framework has been revealed.

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[92] This also appears to be recognised by Ofgem in the RIIO-2 Draft Determinations Finance Annex at Paragraph 3.92.
[93] " RIIO-2 Sector Specific Methodology Decision – Finance", Ofgem, 24 May 2019, paragraph 3.41
[94] " RIIO-2 Draft Determinations – Finance Annex", Ofgem, 9 July 2020, page 32
[95] 'Are sovereign yields the risk-free rate for the CAPM?', Oxera prepared for Energy Networks Association, 20 May 2020
[96]"The cost of equity for RIIO-2 Q3 2020 update", Oxera prepared for the Energy Networks Association, September 2020

The issue came to light because of the CMA's preliminary observations regarding the relationship between WACC and gearing in the context of the NERL provisional redetermination. In this, the CMA found that an increase gearing gave rise to an increase in WACC, contravening the Modigliani-Miller theorem. However, once the correct cost of debt estimate is used, this apparent relationship of WACC increasing with gearing can be explained by an under-estimate of the RFR (see our response to FQ7 above).

Equity analysts and academic theory support the use of a risk-free rate that is higher than the spot yields on ILGs. Oxera have used evidence from equity analysts, academic literature and yields on AAA corporate bonds to determine that a margin above ILG spot yields is required to estimate the RFR in the CAPM. This rate would then reflect the RFR relevant to an equity investor (i.e. a rate for an asset with a beta of 0).

The following bullet points give some of Oxera's reasoning and the evidence they have reviewed, but we refer Ofgem to Oxera's latest report for the ENA[97] for their full explanation of the issue, the evidence they have reviewed to quantify it, and the resulting estimate of the adjustment that should be made to gilt rates to give a value of RFR that can be used in the CAPM:

- The CAPM assumes that investors and firms can borrow at the RFR. However, even with the best credit ratings, non-government investors cannot access debt at the spot rate of ILGs.
- In that respect, evidence from academic research shows that unadjusted spot yields on government bonds cannot always be used as a proxy for the risk-free rate in the CAPM framework. To be used as a proxy for the RFR, the spot yields on ILGs need to be adjusted for the unique features of ILGs:
    - A convenience ('money-like') premium attached to ILGs that pushes down government yields relative to the RFR
    - The gap between the corporate and sovereign risk-free financing rates
- The RFRs assumed by sell-side analysts covering utilities in the UK are also found to be consistently higher than the spot yields on ILGs
- To quantify the effect, Oxera have assessed the yields on AAA-rated corporate bonds, as well as their spreads over UK ILGs, and then considered the yields on AA-rated bonds as a cross-check.
    - Table 2.1 in Oxera's latest report[98] indicates that the AAA spread has ranged between 70bps and 80bps in the last six months, suggesting that the RFR would be underestimated if it was set equal to spot or forward yields on government bonds.
    - Oxera next considered the evidence to show how much of the observed AAA yield represents compensation for expected loss and a premium for systematic risk: based on several studies, Oxera conclude that at a ten-year horizon, the yields on AAA corporate bonds minus up to 5bps to account for a default risk premium is a reasonable proxy for the RFR to use in the CAPM, and at a twenty-year investment horizon, AAA corporate bond yields with a downward adjustment of 5–20bps could be used as a reasonable proxy for the risk-free rate to use in the CAPM.
- Oxera then show at Table 2.4 and 2.5 in their latest report how this adjustment can be built into and combined with Ofgem's proposed approach to take account of movements in RFR rate each year when setting cost of equity allowances during RIIO-T2. Oxera conclude that, based on rates at 31 July, -1.0% would be appropriate assumption for the RFR during the years of RIIO-T2 (on a real basis relative to CPIH) - though we note from the top

[97] Ibid.,

[98] "The cost of equity for RIIO-2 Q3 2020 update", Oxera prepared for the Energy Networks Association, September 2020, page 12

paragraph on page 14 and from Table 2.5 in Oxera's report that a RFR of -0.79% or -0.73% (= -1.48% + 0.75%) would be the value that corresponded to the gilt rates used by Ofgem when calculating the –1.48% RFR in the DD.

- The difference between these Ofgem's and Oxera's approaches, c.0.75% when based on the same underlying gilt rates, reflects the gap between risk-free corporate and sovereign financing rates, and shows the scale of the error that would be introduced by basing the RFR parameter used in the CAPM on the yields on government borrowings without taking account of the unique features of sovereign bonds.
- If Ofgem retains their proposed RFR indexation approach based on ILGs which is updated each year through RIIO-2, this would require an adjustment to be applied, by adding 0.75% to the rate that was calculated each year.

The notional equity beta is too low due to Ofgem's overestimate of debt beta and underestimate of the asset beta

The notional equity beta value used by Ofgem in the CAPM in the DD to calculate the cost of equity for RIIO-2 is too low. The main market and qualitative evidence is discussed in our response to question FQ5 above concerned with the relative risk of different sectors (and the related asset beta). We refer the reader back to that response in the context of this question FQ9. We do not repeat this evidence here. In this section, we concentrate on another key part of the beta estimation, the debt beta. We explain why the DD assumption of 0.125 is overstated.

It is unclear what evidence Ofgem are now using to support the debt beta value of 0.125 that was used in the DD. Ofgem have taken a value of 0.2 referred to by CEPA[99] and attributed to Oxera[100] out of context as it was not an estimate of debt beta. Instead it was the result of a simple regression, but additional factors needed to be included in the regression in order to properly estimate the debt beta, as Oxera's report explained.

The other evidence referred to in the SSMD that supported higher beta values is found, on examination, not to support higher values of debt beta (0.1 to 0.2) rather than lower values (0.05 or less). Only two of the references considered by Ofgem supported values at or approaching 0.2. The first is attributed to Fama and French, but this appears to suggest that the debt betas of investment grade bonds are between –0.02 and 0.02, and the second is the well-known Brearley & Myers "'Principles of Corporate Finance" textbook, but this simply makes a general and non-specific observation that '*debt betas of large firms are typically in the range of 0 to 0.2*' without indicating a preference for any part of the range. Once these sources are put to one side, both the remaining evidence in SSMD and the more rigorous and sophisticated studies carried out by Oxera suggest that the debt beta value should be 0.05 or less.

Finally, Oxera have further considered the evidence for debt beta values in some depth using a range of estimation methods in Section 3.2.2 of their latest cost of equity update report[101]. These include CEPA's application of the structural method in the December 2019 report for the

[99] At paragraph 3.39 of the RIIO-2 Draft Determinations - Finance Annex and on page 196 Ofgem refer to page 10 of CEPA's "Considerations for UK regulators setting the value of debt beta" report for the UK Regulators Network, 2 December 2019

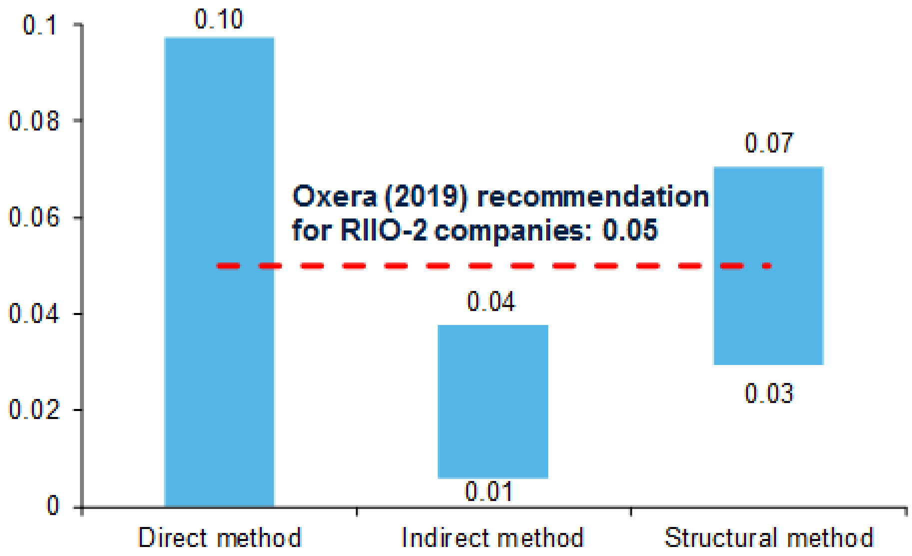
[100] CEPA referred to page 21 of Oxera's report "Review of RIIO-2 finance issues: The estimation of beta and gearing" prepared for Energy Networks Association, 20 March 2019, and reproduced the words *"If (again for July 2013 – June 2018) we simply regress returns on a portfolio of National Grid debt against the FTSE we obtain a coefficient of 0.20 (t = 2.48)"*. If the extract had been continued instead of being cut off at that point, and was read in the context in the rest of this section of Oxera's report, it would have been clear that this 0.2 figure was not considered by the authors of the Oxera report to be a debt beta estimate.

[101] "The cost of equity for RIIO-2, Q3 2020 update", Oxera prepared for Energy Networks Association, September 2020

UKRN '*Considerations for UK regulators setting the value of debt beta*'. Oxera identify two errors in CEPA's calculations, and when these are corrected this method too gives an estimate debt beta of 0.05[102]. Oxera also address CEPA comments on the various other estimation methods in CEPA's report for the UKRN.[103]

The evidence for debt beta values from the different methods is summarised in the chart below taken from Oxera's new report [104]:

Figure 10 Evidence on Debt Beta



Oxera conclude that the estimates from direct and indirect regressions as well as from the corrected version of CEPA's structural method support a debt beta assumption of 0.05 for regulated network companies. This addresses Ofgem's comment in the DD that *"Oxera's view on debt beta seems heavily dependent on only one method of estimation, an indirect method."*

Further detail on our response to Ofgem's proposed debt beta methodology or provided in Appendix 3 to this annex.

In the absence of any evidence to support a debt beta of 0.125, it would then be an error for Ofgem to use this value in Final Determinations, and a value of 0.05 should be used instead.

Conclusion on Step 1 - CAPM evidence

Our conclusion is that Ofgem has very significantly underestimated each of the CAPM parameters (TMR, RFR and notional equity beta), and as a result the proposed cost of equity in the RIIO-2 DD is too low.

Step 2

Moving on to Step 2, cross-checks are just that – cross-checks – but those proposed by Ofgem, once corrected and seen in the proper light, are found not to support Ofgem's proposed cost of equity allowance. Ofgem summarises its view of its cross check in the DD at Table 24. Our views on these cross-checks were given in our response to question FQ8 above and appendix 1, but are summarised in very abbreviated form in Table 10.

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[102] Ibid, Figure 3.4.
[103] Ibid, section 3.2.2
[104] Ibid, see Section 3.2.2. and Figures 3.1 to 3.4 in particular for further details.

Table 10: Summary of our views on Ofgem's proposed cross checks to cost of equity

Cross Check of the Cost of Equity proposed by Ofgem	National Grid's view of the cross check (the CPIH-real cost of equity it gives; and/or comments on the relevance of the cross-check)
Modigliani-Miller cost of equity inference (WACC cross-check)	Once the cross-check is carried out properly, and appropriate parameters for the different input parameters are used, the calculated WACC is almost insensitive to the gearing level, so this cross-check simply gives a result that is consistent with the CAPM estimate. Whilst there may be values for different comparator companies and for different sample lengths etc, these variations are equally apparent and are better assessed in the analysis of the asset beta (and notional equity beta) levels for different comparators. They have therefore already been taken into account in forming a view of the CAPM parameters, which should be based on all the available evidence taking account of the relevant company characteristics, rather than just a small number of selected data points (which is what this cross-check would do). Weight should therefore not be placed on this cross-check.
MAR-implied cost of equity	MAR analysis depends on many assumptions and as a result is unable to give a clear indication of investors' return requirements or expectations. The observed MAR values can be explained without a need to assume that investors are being overcompensated.
Unadjusted OFTO implied equity IRR	OFTO projects have different (and lower) risk profiles than those of UK energy networks, so the OFTO implied IRR does not provide a meaningful cross-check.
Unadjusted investment managers (TMR) cost of equity	We don't support attaching significant weight to these views. However, even Ofgem's values of investment manager views of TMR are somewhat higher than the cost of equity proposed in draft determinations.
CAPM with 0.9 equity beta & investment managers' TMR	Investment managers views of TMR would be more relevant as a check of TMR than of the estimated cost of equity reached in Step 1 using the CAPM (though we still don't support attaching significant weight to them). Once likely conservatism in these values is considered; an upward adjustment is made to correctly allow for geometric averaging; inconsistencies in two of the data points referred to by Ofgem are removed; and the implications of the much higher values shown by the small number of more recent manager's TMR values are considered, the Investment Manager views of TMR would support use of much higher values of TMR than Ofgem assumed in the Draft Determinations
Unadjusted infrastructure fund implied equity IRR	Infrastructure funds have different (and lower) risk profiles than those of UK energy firms, so (like OFTO returns) the infrastructure fund implied IRR does not provide a meaningful cross-check. Ofgem's calculations of infrastructure fund discount rates also rely on an assumption that any premium above NAV means that the fund is overestimating its own cost of capital, but there are multiple explanations for market valuations that do not rely on the overestimation of cost of capital.

Oxera have similarly carried out an analysis of Ofgem's cross-checks, and also reached the conclusion that they cannot be used as robust cross-checks of the cost of equity, although the investment manager evidence appears to support a TMR more in line with Oxera's estimates once obvious outliers are discarded[105].

As explained in our response to FQ8 above, in place of the cross-checks that Ofgem have considered, there is a more objective and relevant cross-check that should be used instead:

- **Asset Risk premium – Debt Risk premium:** Oxera have identified and described a cost of equity cross-check that is based on the required Asset Risk Premium to Debt Risk Premium (ARP to DRP) differential. This draws on evidence from debt markets to ensure that the allowed returns set by the regulator for equity are commensurate with the risk associated with operating and owning the associated assets. Oxera's analysis in their November 2019 report showed that their estimated cost of equity range in that report (5.98% to 7.09% relative to CPIH) was supported by this cross-check, as this range implied a differential between the asset and debt risk premium that falls across the middle of the empirically observed distribution of the ARP–DRP differential observed for the bonds issued by UK utilities. Oxera have now produced a new report on this cross-check[106], which addresses Ofgem comments on the method and updates the earlier estimates. It concludes that this cross-check shows that Oxera's updated cost of equity range from 6.00% to 7.08% (CPIH real) at 60% notional gearing is broadly in line with the recent market evidence. In contrast the analysis shows that Ofgem's DD mid-point cost of equity (4.2%) is significantly below recent market evidence and would need to be increased by 2.15% to bring its implied the ARP−DRP differential up to the median derived from contemporaneous market data - though because to the attenuation bias in the benchmarks, this is a conservative estimate of the size of the increase required to place the cost of equity proposed in DD in line with contemporaneous market benchmarks[107].

Taken together, Ofgem's cross-checks do not support the low allowed equity return proposed in DD. Ofgem's proposed cross-check to investment manager forecasts would actually support much higher values of TMR than Ofgem have used once more recent evidence is considered and outliers are disregarded. In addition, the alternative cross-check to the Asset Risk Premium (ARP-DRP) supports a cost of equity that is significantly higher than the figure proposed in the DD (even the top of Ofgem's range).

In conclusion, therefore, when combined with our assessment of the CAPM evidence under Step 1, the available cross-checks confirm that the point value arrived at by Ofgem in the DD at the end of Step 2 is too low and is supported by neither the CAPM evidence under Step 1 nor cross-checks under Step 2 when these are applied and considered properly.

Step 3:

The conceptually and practically flawed outperformance wedge will lead to increased costs for consumers

We continue to disagree with the proposal to distinguish between allowed and expected returns. As we set out in our response to the sector specific methodology consultation, we have fundamental issues with Ofgem's approach in applying a conceptually and practically flawed policy. The allowed cost of equity is a critically important part of the regulatory framework and care needs to be taken in determining the rate for any price control period. Adjusting for an estimate of expected outperformance introduces an arbitrary and unnecessary adjustment. Investors value commitment to regulatory precedent and its established principles. Unjustified

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105 "The cost of equity for RIIO-2 Q3 2020 update", Oxera for the Energy Networks Association, September 2020, Section A2.7

106 "Asset risk premium relative to debt risk premium", Oxera prepared for Energy Networks Association, September 2020

107 "Asset risk premium relative to debt risk premium", Oxera report prepared for the Energy Networks Association, September 2020, page 21

changes of the nature proposed by Ofgem will create uncertainty impacting the stability of the regulatory regime, putting at risk the investment needed to build the energy networks of the future.

We set out below the following key points:

- The allowed equity return is unachievable, layering the conceptually and practically flawed outperformance wedge on top, compounds this error;
- the outperformance wedge undermines the stability and predictability of UK regulation and the incentive properties of the framework;
- Ofgem are virtually alone in supporting the outperformance wedge;
- Ofgem does not aim up in their estimate of cost of equity, risking under investment in UK energy networks;

Finally, these concerns notwithstanding, Ofgem's attempts to justify and quantify the level of the wedge based on historic performance make a range of fundamental errors, including spreadsheet errors which speak to *"weak quality control in presenting this work and adds an extra layer of confusion to any attempt to follow Ofgem's work"*[108] and a reliance on irrelevant data that tells Ofgem nothing about the true performance that can be expected in RIIO-2 (see our response to FQ10).

Frontier Economics critique of Ofgem's policy[109] shares many of our concerns and sets out responses to both Ofgem's calibration of the outperformance wedge and the implementation of the backstop that were set out in the DD. It also responds to Ofgem's reaction to their original report[110] that were set out in the SSMD.

We would also draw Ofgem's attention to research performed by John Earwaker and Nick Fincham, sponsored by National Grid, that surveyed the views of 31 ex-regulators from across the UK's regulated sectors, most of whom have held Board positions on UK regulatory bodies. This research identified significant concern amongst the respondents to the survey in relation to adjusting allowed returns for expected future outperformance. For example, they found 24 out of the 31 respondents disagreed with the *"lump-sum deduction from allowed revenues to capture otherwise overlooked scope for the regulated firm to make cost savings and/or output improvements"*[111].

The allowed equity return is unachievable, layering the conceptually and practically flawed outperformance wedge on top, compounds this error

Our analysis, which is included in the "Unachievable allowed equity return" section of the summary narrative of this document, shows that investors cannot expect to achieve the allowed equity return in RIIO-2. Therefore, to assume that investors expect 25bps of outperformance is flawed and does not take into account the nature of the RIIO-2 framework.

From a conceptual perspective, the justification confuses windfall gain from poor price control setting and outperformance from incentives. If the wedge is meant to apply to windfall gain, then this suggests lack of confidence in proper calibration of the price control even before it has been attempted. This cannot be the case as noted by respondents to a recent survey of ex-regulatory practitioners[112] *"regulators are normally required to calibrate point expenditure*

[108] "Further analysis of Ofgem's proposal to adjust baseline allowed returns", Frontier Economics prepared for Energy Networks Association, September 2020, page 40

[109] "Further analysis of Ofgem's proposal to adjust baseline allowed returns", Frontier Economics prepared for Energy Networks Association, September 2020

[110] "Adjusting baseline returns for anticipated performance: An assessment of Ofgem's Proposals" Frontier Economics, 12 March 2019

[111] http://www.first-economics.com/earwakerfincham.pdf

[112] http://www.first-economics.com/earwakerfincham.pdf

allowances and output targets from a range of admissible values... ...a regulator ought to focus on where in these ranges its assumptions ought to be pitched rather than state, in effect, that such judgments must somehow be wrong". Ofgem has adequate tools and data to be able to achieve this and is also proposing to introduce Return Adjusting Mechanisms (RAMs) to deal with any significant windfall gains or losses if they were to arise.

If instead, the wedge is being introduced in relation to outperformance from incentives, then the approach does not recognise and appreciate the consumer benefit of incentives-based regulation, the widely accepted solution to the existence of monopoly. In this model, expected return will differ from allowed return to the benefit of consumers. To converge the two would result in a reversion to rate of return regulation and undermine the behaviours that drive dynamic efficiency which has delivered huge benefit to consumers over the last 25 years.

Frontier have calculated that if the impact of the outperformance wedge on company incentivisation were to reduce the annual cost savings from efficiency improvements by 25% then the loss of productivity gains would outweigh the savings from the 25bps outperformance wedge by 2022/2023. Even a very conservative assumption of a 10% loss of efficiency gains would have a cross over point of 2027/2028.

From a practical perspective there is little evidence to support Ofgem's calibration of the wedge. RIIO-2 is fundamentally a different price control to RIIO-1, it is therefore not reasonable to look at the performance in RIIO-1 or prior price control periods to predict RIIO-2 performance. At the very least a comprehensive set of adjustments would need to be made (to the extent the data is available) to cope with the myriad of changes that include, for example, the new PCD methodology and NARMs framework, more stretching productivity and efficiency assumptions, reduced incentives, replacement of IQI with the BPI, absence of fast tracking, and more stretching benchmarking. A more exhaustive list of the required adjustments is provided by Frontier in their report for the ENA[113].

Ofgem sets out a database of historical price control performance as part of the DD which suggests on average price control totex allowances are outperformed by 7%. Frontier have reviewed this on behalf of the ENA and find it to contain multiple errors so it cannot be relied upon. Our response to FQ10 below sets out more detail. As a result, the outperformance wedge is analogous to an unjustified 5% totex efficiency, similar to the Smart Grid efficiency adjustment Ofgem included in RIIO-ED1 only for it to be overturned on appeal to the CMA[114].

The outperformance wedge undermines the stability and predictability of UK regulation and the incentive properties of the framework

The past stability and predictability of the WACC-setting process is the cornerstone of the UK regulatory model, where the focus has been squarely on achieving two highly desirable outcomes:

- maintaining investor confidence in order to keep investors' true cost of capital of investing in the industry low; and
- stimulating significant dynamic efficiency improvements (in large part through a predictable approach to remuneration of assets and performance).

The outperformance wedge, for which there is no known precedent or satisfactory conceptual or evidential basis, undermines those benefits.

In applying its adjustment to the WACC, which is then applied to the RAV, Ofgem is in effect retrospectively clawing back the value of past investments. This runs counter to established

[113] "Further analysis of Ofgem's proposal to adjust baseline allowed returns", Frontier Economics prepared for Energy Networks Association, September 2020, section 4.2.2
[114] Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc v the Gas and Electricity Markets Authority, CMA (2015)

regulatory practice in the UK, has no support from economic consultants, so far as we are aware, and will unquestionably undermine investor perceptions of risk and company behavior.

In calibrating its downward adjustment by reference to historical outperformance, Ofgem is clearly signaling that future outperformance will affect its future calibrations of the downward adjustment. As a result, companies will enter into a price control period with the knowledge that any incremental outperformance achieved will lead to an incremental worsening of future price controls calibrations. This will dampen incentives for innovation and efficiency to the longer-term detriment of customers.

Frontier Economics work[115] shows that a reduction of only 4% in historical productivity gains brought about by the outperformance wedge would lead to increased costs to consumers and goes on to state that *"We have not yet seen satisfactory assessment from Ofgem to date to suggest that the pros and cons of this mechanism have been appropriately considered"*.

Ofgem are virtually alone in supporting the outperformance wedge

It appears, Ofgem is wedded to the outperformance wedge adjustment whilst networks are equally and uniformly opposed to its implementation. This can happen on the more contentious elements of any price control. However, we would urge Ofgem to step back and look more broadly at the views of regulatory professionals and the actions of other regulators. As Frontier highlight, Ofgem is the only regulator to embrace such an adjustment and even the authors of the UKRN report were divided on this recommendation.

This is highlighted in the survey of ex-regulators performed by John Earwaker and Nick Fincham[116], with 24 out of 31 respondents disagreeing with the principle of making a lump sum adjustment to cost of equity, noting *"they disliked the concept of a final, stand-alone catch-all down-sizing of revenues and considered that it would be much better for a regulator to express any additional challenge that they felt it necessary to give a regulated firm more directly within one or more of their price control building blocks"*.

Ofgem does not aim up in its estimate of cost of equity, risking under investment in UK energy networks

We disagree with Ofgem's decision not to 'aim up' in its allowed cost of equity estimate. Ofgem's estimate of an allowed equity return of 3.95% (at 60% gearing), within their CAPM implied cost of equity range of 3.64% to 5.00% represents an allowed return in the bottom quartile of their range. This is achieved through selection of a mid-point estimate within their CAPM implied range and further downward adjustment as a result of their cross checks and the outperformance wedge.

Frontier[117] find this represents a departure from well-established regulatory and CMA precedent, with a paper by Ian Dobbs (2011) cited as primary evidence for selecting a point between the 75th to the 90th percentile. This is on the basis that the detriment to consumers of setting cost of equity too low far outweighs the impacts of it being too high, the risk being that investments are deferred or cancelled because they no longer meet hurdle rates. It is also inconsistent with the paper published by the UKRN on the estimation of the cost of capital for the purposes of price controls in the UK which concluded that: *"with relatively low elasticities, the reduction in consumer surplus from setting a higher price is relatively small. In contrast, the welfare loss from setting the price too low (i.e. setting too low a RAR) is relatively large. This*

[115] "Further analysis of Ofgem's proposal to adjust baseline allowed returns" Frontier Economics prepared for Energy Networks Association, September 2020
[116] http://www.first-economics.com/earwakerfincham.pdf
[117] "Further analysis of Ofgem's proposal to adjust baseline allowed returns" Frontier Economics prepared for Energy Networks Association, September 2020

leads to considerable aiming up, as the optimal choice by the regulator"[118]. Similarly, in its 2007 review of airports, the UK Competition Commission (now the Competition and Markets Authority) stated: *"If the WACC is set too high then the airports' shareholders will be over-rewarded and customers will pay more than they should. However, we consider it a necessary cost to airport users of ensuring that there are sufficient incentives for BAA to invest, because if the WACC is set too low, there may be underinvestment from BAA or potentially costly financial distress…Most importantly, we note that it is difficult for a regulator to reduce the risks of underinvestment within a regulatory period. Taking these factors into account, we concluded that the allowed WACC should be set close to the top of our range"*[119].

Frontier identify the material harm that can arise from under investment, which for example can lead to the worsening of operational performance, stifling of innovation, and reduction in the adoption and roll out of low carbon technologies. Further, Frontier find that the consumer benefit of under-remuneration in the form of a lower allowed return would easily be (more than) offset by the cost of only slightly worse quality of service.

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

a) "AR-ER database.xlsx"

b) "Residual outperformance.xlsx"

c) "Simple MAR application model.xlsx"

Frontier were engaged by the ENA to review and critique Ofgem's calibration of the outperformance wedge. We have provided a summary of their findings below and would refer Ofgem to Frontier's full commentary on the calibration of the outperformance wedge which is set out in Chapter 4 of their report[120]. The report addresses both the conceptual flaws in Ofgem's attempt to calibrate the outperformance wedge as well as a detailed critique of the errors and omissions Ofgem has made in its calculation of the quantum of the adjustment. Frontier have also corrected and recalculated Ofgem's workings where possible, however it should be noted that due to a number of shortcomings in the data inputs and methodology of preparation and a lack of clarity from Ofgem on its intended purpose it has not been possible to fully reperform the calculations in the "AR-ER database.xlsx" in the time available.

Our comments to FQ10 should be read alongside our answer to FQ9, where we set out our fundamental concerns with Ofgem's policy of impost a downward adjustment to expected returns, which is conceptually and practically flawed.

The principle of Ofgem's approach to rely on past performance to calibrate future performance is flawed

Ofgem has included price controls dating all the way back to privatisation in its database and presumably in the histogram they use to support their assertion that past performance implies "*an average [totex] underspend of approximately 7%*". However, the purpose of many of the earlier price controls was to set a fixed revenue alongside very strong incentives that would provide strong inducement for relatively recently privatised companies to reveal efficiencies as

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[118] UKRN (2018), Estimating the cost of capital for implementation of price controls by UK regulators, 6 March, page 163.

[119] Competition Commission (2007), 'BAA Ltd: A report on the economic regulation of the London airports companies (Heathrow Airport Ltd and Gatwick Airport Ltd)', presented to the Civil Aviation Authority, 28 September, paras 4.106–8.

[120] "Further analysis of Ofgem's proposal to adjust baseline allowed returns" Frontier Economics prepared for Energy Networks Association, September 2020

aggressively as possible. This they did, in spades, often easily outperforming the price control (e.g. the database includes 18% outperformance in DPCR2).

Whilst this is a useful reminder of both the power of incentivisation in revealing efficiencies in the consumer interest and the relative sophistication of the current rate setting process, it reveals nothing about the level of outperformance an investor or regulator should expect to see in RIIO-2. It is interesting to note that Frontier find that "*removing DPCR1 to 3 and PCR2002 reduces the mean observed outperformance to 3.7% (based on 160 observations)*"[121] from 7%. Although, as Frontier notes, this is not meaningfully more relevant given the other shortcomings of the dataset which include:

- the inclusion of airports and air traffic control is of limited relevance and highly misleading. For example, Heathrow has an average revenue form of price control, so there is a need to control for volumes. However, no attempt has been made to do this, and so its inclusion in the database undermines Ofgem's analysis;
- the very significant changes between RIIO-1 and RIIO-2 which have not been properly accounted for in Ofgem's analysis, which are summarised below and discussed in more detail in Frontier's report[122];
- the apparent contradiction in Ofgem's approach of using a one size all adjustment of 25bps, when Ofgem's Table 26 shows that outperformance can differ depending on the incentive strength and totex:RAV ratio; and
- the fact that it is possible to set broadly symmetric price controls as Frontier highlight in their report. In Ofwat's evidence to the CMA, which is quoted by Frontier it shows it set allowances so that average outperformance against totex has ranged between –0.2% and +1.4% between 2005 and 2019.

Ofgem's totex outperformance database (AR-ER database.xlsx) is poorly thought through, difficult to follow and its outputs are largely irrelevant to calibrating the outperformance wedge

Frontier have spent considerable time and resources in reviewing Ofgem's spreadsheet. Their findings are that the spreadsheet has very little signposting and in particular it is unclear what Ofgem have relied on in putting its data together. Some examples of the issues Frontier identified include:

- the inclusion of two highly contradictory sets of water data, one of which seems to "*bear no relation to the evidence submitted by Ofwat to the CMA*";
- arbitrarily excluding TPCR3, whilst including TPCR1, 2 and 4. Frontier note that the inclusion of TPCR 3 would not materially change the result, but it does speak to a lack of proper quality control over the spreadsheet; and
- numerous hard coded cells which makes it difficult to audit and comment on.

Frontier conclude that the construction of the spreadsheet "*falls short of best practice*". It is concerning that such a spreadsheet is being used by Ofgem in its price control process. Although our more fundamental concerns are with the conceptual shortcomings of expecting the past performance of price controls set over a time period when regulation has changed so radically could ever predict future performance.

[121] "Further analysis of Ofgem's proposal to adjust baseline allowed returns" Frontier Economics prepared for Energy Networks Association, September 2020

[122] "Further analysis of Ofgem's proposal to adjust baseline allowed returns" Frontier Economics prepared for Energy Networks Association, September 2020, section 4.2.2

Ofgem's analysis of RIIO-1 performance restated to a RIIO-2 basis (Residual outperformance.xlsx) contains calculation errors and misses critical differences between RIIO-1 and RIIO-2, which when corrected show there is "very little prospect of outperformance in RIIO-2"[123]

RIIO-2 is fundamentally a different price control to RIIO-1. It is therefore not reasonable to look at the performance in RIIO-1 to predict RIIO-2 performance, we therefore have fundamental concerns with Ofgem's approach to calibrating the outperformance wedge. However, the ENA engaged Frontier to review and reperform the calculation in "Residual outperformance.xlsx".

Frontier's approach was firstly to correct Ofgem's spreadsheet error which overstates the outperformance in RIIO-GT1 and then went on to adjust for the numerous differences between RIIO-1 and RIIO-2 which had not been captured by Ofgem's original analysis. Frontier provide an extensive list of the adjustments that are required to complete Ofgem's restatement exercise, we summarise the main components below:

- tougher benchmarking of efficiency
- broader application of efficiency challenge and higher assumed productivity improvements
- the historic use of interpolation in the IQI, which is no longer the case, the widespread use of penalties in the new BPI, and the removal of the opportunity for fast track status
- the widespread use of PCDs and UMs and changes to the NARMs regulations, which all serve to reduce the scope for outperformance
- the marked toughening in approach to calibration of a range of output incentives
- the switching off of some incentives between RIIO-1 and RIIO-2

Frontier find that: *"...that **there is very little prospect of any outperformance at RIIO-2** (putting to one side the ED sector for which it is far too early to comment on what Ofgem intends).*

*In particular, our results show that **there is almost no opportunity to deliver totex outperformance**, and this is despite the fact that there are additional changes between RIIO-1 to RIIO-2 which have not been reflected in our analysis (such as the introduction of NARMs and PCDs)"*.

Frontier go on to illustrate, based on work performed for NG and Northern Gas Networks that neither of NG's transmission networks or a notional GD network can expect to outperform RIIO-2 with an expected RORE outperformance of at least –20bps in all three scenarios, they put the likelihood of NGET and NGGT of outperforming by 25bps or more at 1.7% and 12.6%, respectively. Frontier conclude *"This suggests that the outperformance wedge cannot be applied ex-ante, because in the majority of cases, the outturn performance is likely to be lower than the point at which the wedge is set"*.

More importantly, analysis included in the "Unachievable allowed equity return" section of the summary narrative of this document shows that investors cannot expect to achieve the allowed equity return in RIIO-2. Therefore, to assume that investors expect 25 bps of outperformance is flawed and does not take into account the nature of the RIIO-2 framework.

Ofgem's use of MAR evidence does not recognise the uncertainty inherent in this type of evidence

[123] "Further analysis of Ofgem's proposal to adjust baseline allowed returns" Frontier Economics prepared for Energy Networks Association, September 2020

We do not agree that MAR evidence supports the calibration of the outperformance wedge. The use of MAR evidence is highly judgmental, as recognised by CEPA themselves in their report for Ofgem[124] and also on a number of occasions by the CMA (see our response to answer FQ8 and Appendix 1 on cross checks to cost of equity). It is also unclear to us how CEPA have performed their analysis which is contradicted by recent sell side estimates of trading premia for National Grid.

The uncertainties in calculating and interpreting MAR data have been recognised by, amongst others, the authors of the UKRN reports, the CMA and CEPA:

- UKRN cost of capital study (2018): *"What is evident from this analysis is transaction premia alone do not provide sufficient evidence to make inferences about the cost of equity. Different drivers of outperformance are at play and multiple combinations of various drivers can explain observed premia. In addition, the role of expected outperformance means that the premia may result from unobserved investor assumptions that may be considered unrealistic or optimistic but are nevertheless the reality behind the premia"*[125].
- The CMA and its predecessor, the Competition Commission (CC), have considered MARs in the context of previous regulatory appeals. This regulatory precedent (set out and considered in Oxera's report for the ENA[126]) recognises the significant uncertainties associated with interpreting MARs.
- CEPA themselves recognise the practical challenges of using MAR evidence under the chapter heading *"There are considerable practical challenges in directly inferring the underlying cost of equity using MAR evidence"*[127].

The source of uncertainty in interpretation of MAR arise from a number of different sources. These include:

- Analysts and investors have limited information. Therefore, Ofgem may find that an observation of a MAR above one reassures them about the calibration of the outperformance wedge but investors views may change over time as more information is available as companies report performance in RIIO-2.
- Oxera's report for the ENA[128] shows that analysts fundamentally disagree with the sources of MAR in the listed water sector. Which highlights the relatively limited information analysis have at their disposal and the difficulty in performing a disaggregation of the MAR. There is no one answer that can be used to make judgments on price control calibration.
- The MAR does not necessarily tell us any more about investors views of RIIO-2 than it does about RIIO-3, or subsequent price controls. It is a very imprecise and opaque tool for testing the calibration of any particular price control.

Both Ofgem's DD and CEPA's report include two versions of the MAR calculation, one using the market value of debt and one using the book value of debt. Ofgem describes the market value of debt approach as their preferred approach, although provide no explanation to support their preference. This view appears to be at odds with their consultants who state *"use of market debt values creates complications, both when calculating the MAR in practice and when attributing the proportion of an observed premium to RAV that might influence a regulatory*

[124] "RIIO-2: Use of Market Evidence" CEPA for Ofgem, 9 July 2020
[125] UKRN (2018), Estimating the cost of capital for implementation of price controls by UK regulators, 6 March, page 177
[126]"The cost of equity for RIIO-2, Q3 2020 update", Oxera prepared for Energy Networks Association, September 2020
[127] "RIIO-2: Use of market evidence", CEPA, 9 July, page 29
[128] "What explains the equity market valuations of listed water companies" Oxera prepared for Energy Networks Association, 20 May 2020

decision... …MARs that incorporate a market value of debt may include a component that reflects the decline in interest rates and does not reflect either expected outperformance or an expectation of premium allowed returns on equity"[129] and also note that *"Using book values of debt in the MAR calculation instead helps address some of the practical issues with calculating an MAR using market debt values*".

CEPA have not published the detailed calculations so it is not possible for us to review their methodology. However, it is at least possible for us to note that CEPA's observations contradict that of sell side equity analysts who have published their view of trading premia for NG since the 9 July. This shows a range of estimates of between +11% and –9%, with an average value of zero.

Table 11: Recent sell side estimates of NG's UK trading premia

Bank	Report Date	Trading premia of NG's UK Regulated businesses
Barclays	13 August 2020	0%
Jefferies	27 July 2020	11%
Soc Gen	16 July 2020	0%
Barclays	9 July 2020	-9%
Credit Suisse	9 July 2020	-1%

The range of estimates from sell-side analysts show the uncertainty inherent in calculating MAR, even from a group of specialist equity analysts. The variation can arise due to a number of reasons including the method of disaggregation and in particularly the assumptions required about valuations of other group assets, the valuation of any provisions to calculate the enterprise value, and the timing of when the analysis is performed as share price changes have a material impact on the level of the observed MAR.

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

We do not support an ex-post adjustment for baseline equity return ('the backstop') as it represents an additional complexity that creates perverse incentives and reduces the legitimacy and clarity of the framework. The fact that Ofgem feels the need to introduce the backstop mechanism at all, shows that Ofgem have little faith in their ability to accurately calibrate the outperformance wedge. It is worth noting that, somewhat counterintuitively, given the low level of ODI's available, the backstop adjustment will likely be used when actual RIIO-2 totex is close to Ofgem's final RIIO-2 allowances.

Our issues with the backstop mechanism are:

- It creates an unnecessary and perverse incentive.
- The additional complexity risks undermining the clarity and legitimacy of the framework.
- There are practical problems of how calibration of the two groups will work in practice.

We do not think there are changes to the mechanism that can avoid these issues and would instead recommend that the outperformance wedge itself is removed from the framework, as per our response to FQ9.

[129] "RIIO-2: Use of Market Evidence" CEPA for Ofgem, 9 July 2020

It creates an unnecessary and perverse incentive

Conceptually, the backstop introduces a perverse incentive to overspend against allowances where networks expect average RoRE over RIIO-2 to be less than 25bps below the expected return. Ofgem have diluted the impact of this perverse incentive by calculating average performance across two groups (electricity transmission and gas). However, Frontier's analysis shows that *"the ex-post mechanism has the potential to reduce incentives by up to 33% in the electricity group and up to 20% in the gas group"*[130]. They go on to state *"Given that this perverse incentive would be layered on top of weakened incentives to outperform, this is a material and concerning impact. This effect would apply across all operational incentives (cost and ODI, but not debt and tax), since it operates at that level"*.

The additional complexity risks undermining the clarity and legitimacy of the framework

Ofgem intends to assess the need and value of any potential backstop adjustment across two groups, electricity transmission networks and gas networks. Within each of these groups there should be 'winners' and 'losers' with some companies achieving a return above the allowed cost of equity and others below the allowed cost of equity. Where the average of these outcomes is below the expected return a positive adjustment to all companies will be made of up to 25bps.

However, from the perspective of the consumer, they will potentially observe the 'winners' of a group, who achieve a return above that of the expected return would be provided an additional 'bonus' payment which appears to arise as the result of the poor performance of other networks within their group, rather than the fact that the outperformance wedge was unnecessary (or at least incorrectly calibrated).

The complexity created by the backstop mechanisms will further undermine the simplicity, clarity and legitimacy of networks performance as it is reported in RIIO-2.

There are practical problems of how calibration of the two groups will work in practice

Within each of the two groups across which performance will be calibrated there are further issues that may arise.

If a minority of businesses within the group (one or more) are calibrated differently to the rest in the group this will distort the outcome, on average, across the group. This could lead to a split in performance, which is particularly likely in the gas sector where you have transmission and distribution business which have seen very different outcomes with respect to BPI and sharing factors, for example. Depending on where the average performance of the group outturns (i.e. greater than or less than the expected return), this could either fail to provide an adjustment to protect the shareholders of the lower performing group or over-remunerate the more strongly performing group, increasing costs to consumers.

Within the electricity transmission group, the NGET business is much larger than the other two networks. A simple average of performance is proposed, presumably to avoid the average performance being almost entirely derived from, in the case of electricity transmission, NGET. However, this creates a situation where relatively modest levels of underperformance by value in SHET and SPT could lead to the simple average of the group return being below the expected return. Any ex-post adjustment would then be applied across not only SHET and SPT's RAV but also the NGET's much larger RAV at significant cost to consumers.

[130] "Further analysis of Ofgem's proposal to adjust baseline allowed returns" Frontier Economics prepared for Energy Networks Association, September 2020

Financeability questions

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

Overview

The overall price control framework must, at its most fundamental level, demonstrably fulfil Ofgem's statutory duty to ensure networks are able to finance licensed activities whilst having regard to the interests of both current and future consumers. It is in the consumers' interest that we fulfil our financing duties as efficiently as possible. This keeps financing costs low and is best achieved by maintaining a strong credit rating and providing confidence to investors that their investment is secure. Despite this, Ofgem's proposals provide neither and the way in which financeability has been assessed raises several concerns:

i) **Misleading financeability ratios:** The financeability ratios quoted in the RIIO-2 Draft Determinations – Finance Annex are misleading and cannot be relied upon because the inputs to the financial model used to generate the ratios are inconsistent with the totex package proposed within the DD documents. On a like for like basis, the NGG baseline totex value within the financial model is £540m higher than that quoted in the documents. Both the totex total and the categorisation show discrepancies limiting the extent to which financeability tests can be relied upon to provide a meaningful assessment of the networks' financial position.

ii) **Inconsistency with rating agency methodologies:** The methodologies underpinning the financeability ratio calculations are inconsistent with those employed by ratings agencies. The cashflows in Ofgem's model assume 25bps of outperformance from day 1 of RIIO-2. Rating agencies would not factor in any outperformance until there is a track record in any price control period. This 25bps is also assumed to provide the equivalent in-year cash uplift as 25bps equity return which will not be the case. In contrast, Ofgem has excluded the cash impact of the BPI penalty yet this is definite, and it is clear from the current formulation a notional Transmission company would attract a penalty.

iii) **Equity financeability not assessed:** Equity risk and return implied by the DD is out of balance. Under Ofgem's package equity investors will bear additional risk for totex uncertainty and downward skewed incentivisation in exchange for returns which are lower than ever. Equity investors are remunerated through current dividend yield and future growth in assets but neither Ofgem's baseline or illustrative scenarios deliver a combined dividend and growth prospect for equity investors which reflects this risk. With notional dividends of 3%, lower than FTSE100 outturns of 4% and utility sector yields of 5%, and a baseline RAV reduction of 1.4% in real terms, Ofgem has been complacent in its approach to financeability by failing to give due consideration to the needs of equity investors. Ofgem's assessment focuses on the debt investor and fails to recognise that if the investment proposition is not sufficiently attractive, shareholders will choose to reallocate capital elsewhere or to regulated utilities in other jurisdictions, resulting in a failure to raise the necessary finance, both in RIIO-2 and subsequent periods.

iv) **Cashflow delays from UMs are not factored in:** Ofgem fails to identify or assess the financeability impact of the cashflow risk arising due to the time delay between spend and revenue recovery. Ofgem's financeability assessment is based on the premise that allowances recognition is fully aligned with investment. This is not the case for funding delivered through uncertainty mechanisms where there is a delay in allowance recognition until an output is delivered or Ofgem issue a determination which could be up to four years. Failure to recognise this time delay, particularly when Ofgem's proposed framework relies heavily on funding through uncertainty mechanisms, excludes a significant cash flow risk from the assessment which materially misstates the financeability of the network.

Overall our conclusion is that the financeability assessment as set out in DD is significantly weakened and cannot yet be relied upon as an effective cross check of the financial framework. We show the impact on, and have restated, the ratios in our response for these concerns. The resulting assessment shows the DD cashflows are not consistent with Baa1 / BBB+ thresholds. This means the DD is a framework which does not provide adequate resilience to absorb macroeconomic shocks and would not enable delivery of outcomes our stakeholders have told us are important to them.

We have engaged Ofgem on our concerns since the DD publication and will work with them to resolve the issues. We have set out remedies that would help including an increase in baseline funding and applying forecasting of outputs for reopeners. We urge Ofgem to ensure all the issues are rectified to ensure stakeholder needs can be met and are not constrained by the RIIO-2 framework.

Remedies required:

- Undertake a financeability assessment which factors in delays between spend and revenue under uncertainty mechanisms.
- Provide additional ex-ante allowances for uncertainty mechanism expenditure and apply forecast of outputs for allowances subject to reopeners.
- Reflect FTSE100 and utility sector benchmarks for dividend yield assumptions used in the financeability assessment

Methodology and interpretation

In our business plan, we set out the principles we adopted in developing our approach to assessing financeability. Whilst Ofgem has carried out a more detailed and transparent assessment than in previous price controls it is not always aligned with our principles which are key in producing to an outcome aligned to consumers' interests. In the following section, we re-iterate our principles and provide an assessment as to how well Ofgem's approach aligns with them.

Focus on notional company

Assess financeability for a notionally efficient company with a capital structure consistent with that used to determine the WACC. This ensures the company and its shareholders bear the risk of the capital structure, not customers.	

Ofgem's assessment is focused on the notional company noting that *"actual company financeability issues are not necessarily for Ofgem to address"*. Whilst we agree that the onus for ensuring financeability of the actual company lies with the networks, this can only be assured with a regulatory framework which delivers a financeable notional company.

As part of this, it is key that the regulator identifies realistically what the notional firm can achieve with respect to cost and incentive outcomes given the price control parameters. Instead, Ofgem assumes a level of cost and incentives performance which is not achievable. Uncertain cashflow from the outperformance wedge is included in the assessment, whilst at the same time the cashflow impact of the BPI penalty is excluded.

Cashflow impacts from the BPI penalty must form part of the notional company assessment because it is clear from the current BPI formulation that the notional transmission company would attract a penalty. All transmission companies have received penalties and the nature of Ofgem's definition of uncertain cost is weighted against transmission companies as they have no direct comparators.

Ofgem's notional assessment relies upon these assumptions to achieve Baa1 / BBB+ thresholds. Notwithstanding our disagreement with the justification for the BPI penalty and the outperformance wedge concept, the assumed cashflow trajectory is not achievable:

- Offsetting the BPI penalty requires totex savings of c£60m, an additional 5% of efficiencies against the baseline, which already includes unprecedented efficiency reductions (in reality this £170m would have to all be in 2022/2023 as BPI is currently assumed to all hit in year 1, equating to 18% of the totex in that year).
- If the outperformance wedge is assumed delivered by totex savings then this would require an additional 5% of totex savings on top.
- delivering ODI performance in line with the 25bps outperformance wedge is the equivalent to achieving ~40% of the maximum reward available from the DD range every year

Work undertaken by Frontier Economics[131] on the expected RoRE from the DD, shows these assumptions are not tenable in reality under the DD framework. Their analysis shows an expected outcome of zero totex outperformance and 7bps outperformance from ODIs. This is not enough to offset the impact one of the BPI or outperformance wedge impacts let alone both. This is before the higher than ever challenge at the start of the RIIO-1 period from unprecedented and unjustified efficiencies are included.

Attractive debt and equity investor package

Financeability assessments should capture the ability to efficiently finance investments through both debt and equity to build a sustainable financial structure.	

Ofgem has been complacent in its approach to financeability by not giving due consideration to the needs of equity investors. Oxera's latest report on the Asset risk premium – Debt risk premium differential[132] (ARP – DRP), sets out how this metric provides an evaluation of equity financeability, showing that the cost of equity is too low compared to contemporaneous evidence.

Ofgem's assessment focuses on the debt investor and fails to recognise that if the investment proposition is not sufficiently attractive, shareholders will reallocate capital elsewhere, resulting in a failure to raise the necessary finance or an increase in the relevant costs, both in RIIO-2 and subsequent periods.

Our business plan provided extensive evidence to explain why a stable, sufficient dividend policy (such as 5% of the equity RAV in line with utility sector averages on the FTSE) is important to investors, yet Ofgem has not responded to our proposals with any sector-based evidence. Instead, they use flawed FTSE100 data, which is not reflective of historical or forecast yields for the FTSE100 of 4% let alone the utility sector, as justification for a dividend yield of 3%. Ofgem then cites this along with future growth in assets as a reasonable investor proposition. This is despite Ofgem's own baseline assessment showing negative underlying asset growth for our networks.

Our investors expect a fair deal which provides the opportunity to earn a return equal to the investment's cost of capital. A shareholder investing in the company would not find it acceptable to be rewarded with a package which consists of a base return that is too low to reflect the risks of running a transmission network combined with an incentives framework

[131] National Grid Wedge update", Frontier Economics, September 2020
[132] "Asset risk premium relative to debt risk premium" Oxera prepared for Energy Networks Association, September 2020

which provides limited opportunity to earn incremental returns. Analysis set out in the summary narrative under “Unachievable allowed equity returns” shows that the DD is not a fair deal and produces a high risk, low return framework where an investor cannot expect to achieve allowed equity return. This does not recognise the critical role that investors take in delivering stakeholder requirements.

Target a strong credit rating

Use a target credit rating of Baa1/BBB+ to ensure financial resilience and consistency with the index used to set regulatory cost of debt allowances	

Ofgem has been explicit that it is targeting an implied credit rating two notches above investment grade (i.e. Baa1/BBB+), consistent with our own approach. We welcome this transparency and agree that targeting a Baa1/BBB+ credit rating for the notional company enables access to an efficient cost of debt and can ensure that we are appropriately resilient to future financial shocks, which is important given our role as owners and operators of critical national infrastructure.

Consider a range of debt metrics based on rating agency methodologies

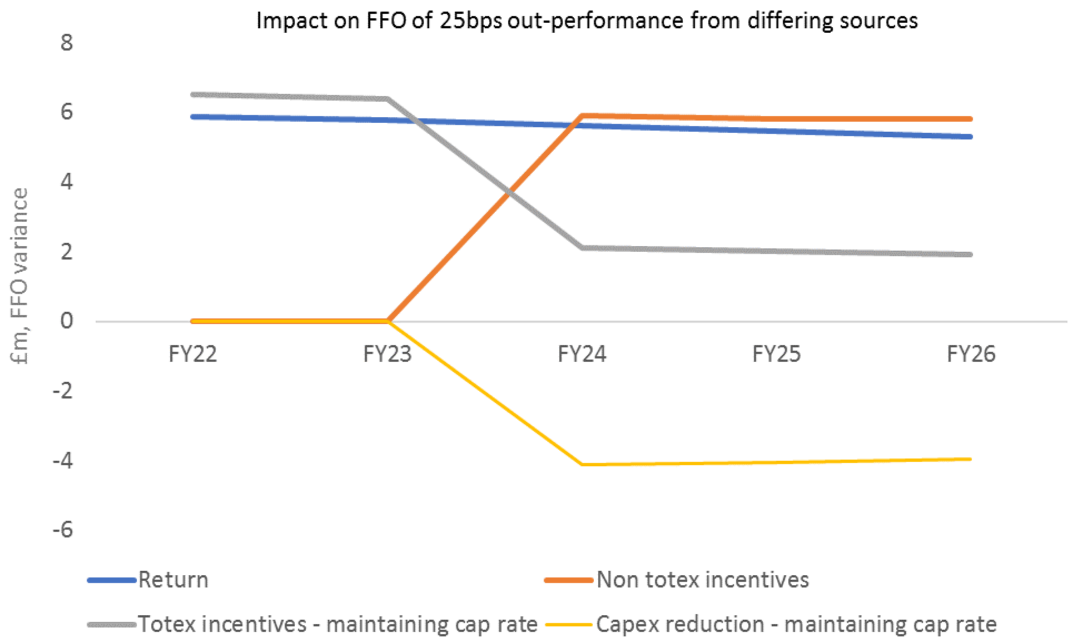
Follow methodologies and focus on key metrics used by credit ratings agencies to aid transparency and consistency	

Ofgem’s financeability tests need to replicate rating agency methodologies as closely as possible to ensure Ofgem’s assessment is consistent with the implied credit level from the viewpoint of the ratings’ agencies. Without this alignment, networks risk being deemed financeable on a theoretical basis by Ofgem but not in practice by the rating agencies, increasing financing costs for consumers. However, clear gaps in approach are evident in the DD.

Ofgem’s approach understates the financeability challenge implied by the DD through inclusion of the outperformance wedge, not only because assumed incentives performance is not credible (as covered in the Focus on notional company section above) but also because Ofgem’s modelling assumes that 25bps performance will give the equivalent credit metric benefit of 25bps of base return. In practice this will not be the case meaning Ofgem’s financeability assessment is showing too positive a position.

To illustrate this, the below graph shows the Funds from Operations (FFO) benefit for differing sources of performance/return factoring in lags in revenue timing. The blue line shows the FFO benefit if the 25bps comes from returns. Only performance based fully on incentives gets to this line, and then only in the last three years given the revenue lag. This position is exacerbated if we were to assume the 25bps was achieved through totex or capex performance.

Figure 11 Impact of 25bps outperformance



This issue is notwithstanding the fact that the notional company should actually be financeable without the need to rely on assumed outperformance. This aligns with the methodology credit rating agencies' will use to undertake their assessment. Moody's have referred to the scope of outperformance being limited by low powered incentives in transmission and challenging cost allowances[133], meaning they will not include any outperformance in their modelling until a track record has been established. It is therefore more credible to assume financeability without assuming any performance.

Ofgem has opted for what they refer to as *"…an in-the-round assessment that targets each notional company being judged as broadly of comfortable investment grade credit quality"*[134]. They do not consider falling below a particular level in one single metric should be an indicator of whether an entity is financeable or not. This ignores the importance rating agencies place on core metrics, the outcome for which often dominate their decisions. For Moody's the key core metric in regard to RIIO-2 is the Adjusted Interest Cover Ratio (AICR) metric and for Standard and Poors it is the Funds from Operations over Net Debt (FFO / Net Debt) metric.

Nor does Ofgem target credit metric results with a buffer against minimum thresholds. The result of setting a price control with notional cashflows that only just reach this threshold is that it increases the risk that rating agencies could place the company on negative watch or downgrade it when event driven risks that the business cannot control outturn. For example, we (and many economic commentators) expect increased volatility in the macroeconomic environment driven by economic events such as Brexit and the COVID-19 lockdown. Taking the recent experience with COVID, we have seen numerous downgrades and negative outlooks on companies that had little or no headroom in their metrics to absorb the increased financial pressure.

To effectively support financial resilience a buffer above the minimum credit rating thresholds must be included in the financeability assessment. We propose this threshold is set at 1.45 for AICR and 9.5% for FFO/net debt, the equivalent of additional cashflows of £5m p.a. This is based on the range we have experienced in our metrics during RIIO-1 and consistency with

[133] Regulated Energy Networks – UK; RIIO-2 proposals support sector's business risk profile, but legitimacy in greater focus, Moody's Investors Service, 3 August 2020
[134] RIIO-2 Draft Determinations – Finance Annex, Ofgem, 9 July 2020, para 5.21

the stress tests we have used to assess financial resilience. Targeting above the minimum threshold provides headroom to absorb downside risks equivalent to a 1% decrease in the gilts rate or a ~0.2% increase in inflation.

Financeability Analysis

In this section, we use the approach we have outlined to highlight where differences in Ofgem's assessment raise concerns around their financeability conclusions. These concerns are captured under the following headings:

- The financeability ratios quoted in the RIIO-2 Draft Determinations – Finance Annex are misleading and cannot be relied upon
- Wholesale use of UMs to manage uncertainty creates a significant cashflow risk and in practice will reduce network agility and responsiveness
- Forecasting of outputs improves financeability but only if re-openers are in scope
- The framework offers limited financial resilience for the network to respond to energy transition in a volatile economic environment
- Ofgem's package does not give due consideration to the needs of equity investors
- There are potential remedies that can help maintain debt and equity financeability

The financeability ratios quoted in the RIIO-2 Draft Determinations – Finance Annex are misleading and cannot be relied upon

We have identified a number of errors when trying to understand the credit metrics from the published financial model, which are either errors of fact or errors of methodology and policy. Starting with the errors of fact:

i) The baseline and illustrative UM totex scenarios do not align with those quoted within the Draft Determination documents

We understand the rationale for excluding RPEs in the DD documents to make them more comparable with company submitted plans, and agree it is appropriate to include for modelling of revenues, but there are a number of material variances highlighted in Table 12 which have an impact on the financial metrics presented in DD documents. In all, the baseline plan is ~£500m higher in the Licence Model than it is in the DD documents.

Table 12 Comparison of baseline totex values

Cost category £m	GT2 Licence Model	Gas Transmission Annex (Table 5)	Variance

18/19 price base	(RPEs removed for direct comparison to Table 14 data)		
Load related expenditure	2.4	2.4	-0.0
Non-load related expenditure	717.8	517.5	200.3
Other costs	258.6	230.3	28.3
Non-op capex	281.3	68.4	212.9
Opex (including network operating, indirect and SO controllable)	838.9	790.7	48.1
Ongoing efficiency	N/A	-50.5	-50.5
Total	**2099.2**	**1558.9**	**540.3**

Turning to errors of methodology and policy:

ii) Ofgem rely on assumed cost and incentives performance to support financial metrics

It is not credible to include expected cashflows from the outperformance wedge or excluding BPI impacts, when assessing financeability. Ofgem's approach implicitly assumes networks can drive incremental service improvements whilst spending less than their totex allowances for the purposes of the financeability assessment. It is inconsistent with credit rating agency methodologies who expect a track record to be established within the price control period before performance can be taken into account. It would be inappropriate therefore to conclude that a financial package is acceptable based on a notional view of how rating agencies might view a regulated network only to find that a very different methodology is applied in practice.

Correcting for both errors of fact and judgment for assessment of the baseline plan shows that AICR has been misstated in Ofgem's analysis and is on average 0.1 lower across the period, but is significantly higher in the first year when AICR drops when the BPI penalty is taken into account.

Figure 12: AICR re-stated to correct errors of fact and methodology

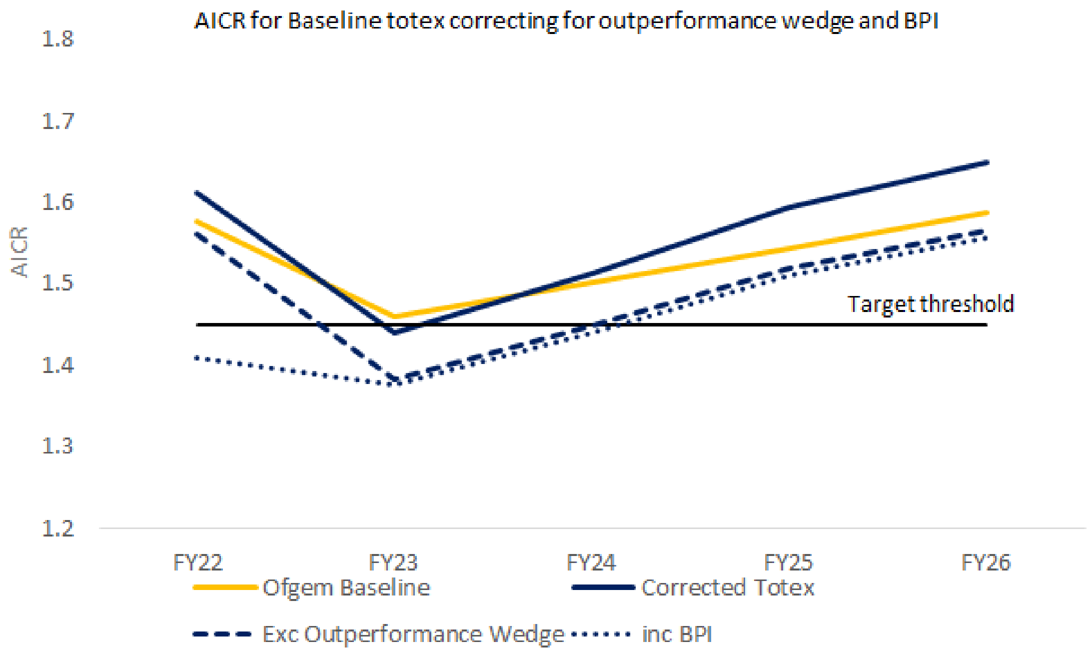


Table 13: key metrics based on baseline totex (£1.6bn) and Ofgem's package excluding incentives performance and including BPI

Quantitative Metrics	T1 Final Proposals	T2				
Dividend Yield	5.00%	2.89%	2.79%	2.68%	4.34%	2.51%
Dividend Cover	2.11	2.71	2.51	2.74	1.87	3.36
Indicated rating from Moody's Grid	A3	A3	Baa1	A3	A3	A3
Core Metrics						
AICR	2.08	1.41	1.38	1.44	1.51	1.56
Net Debt / RAV	63%	58.4%	56.9%	55.2%	54.1%	52.1%
S&P	11.48%	10.53%	10.74%	11.39%	11.97%	12.70%

AICR is a core metric for Moody's and we have applied their approach in line with how Moody's themselves apply the methodology. The core metrics, like the Grid, have their own associated indicative rating, which can be more punitive than the Grid outcome, due to the requirement for strong quantitative factors and can ultimately result in a lower overall rating determined by the Committee.

Our analysis shows that the first three years of the price control are below the target threshold for AICR, and whilst the 5-year average may meet thresholds, rating agencies will only consider a 3-year timeframe when making their assessment. On this basis, GT cannot be considered financeable at the target rating with the baseline plan with the package proposed.

iii) Ofgem's capitalisation rate policy will drive unintended consequences and increase volatility in revenues

We are supportive of a capitalisation policy that equalises incentives but is also based on companies' business plans and so is closely aligned with actual opex / capex split. We have concerns that Ofgem's policy is too restrictive in attempting to achieve these outcomes and is not balanced appropriately with transparency and stability of revenues. Our proposed policy of a single fixed capitalisation rate provides a better balance of these objectives whilst ensuring equalisation of incentives. We provide further details in our responses to FQ23 and FQ24 but for the following analysis we adopt a capitalisation rate policy in line with our proposals.

iv) Ofgem's depreciation policy is not reflective of required investment during T2

We support adoption of a sum of digit's profile to create alignment across the gas sector but Ofgem's depreciation policy needs to go further to ensure assumed asset lives underpinning the depreciation reflect the expected economic life of assets for individual periods of investment. In RIIO-2, the significant proportion of investment will be to maintain the existing network and ensure it continues to be compliant with changing environmental legislation. The asset life is therefore now lower than 45 years with a 30-year asset life more appropriate. We provide further details in our responses to Q22 but for the following analysis we adopt a depreciation policy, so that for RAV additions from 2002 to 2021 the depreciation is on a 45-year, sum of digit basis, with a 30-year asset life for T2 additions.

From here on, our financeability analysis will correct for these errors and be based on:

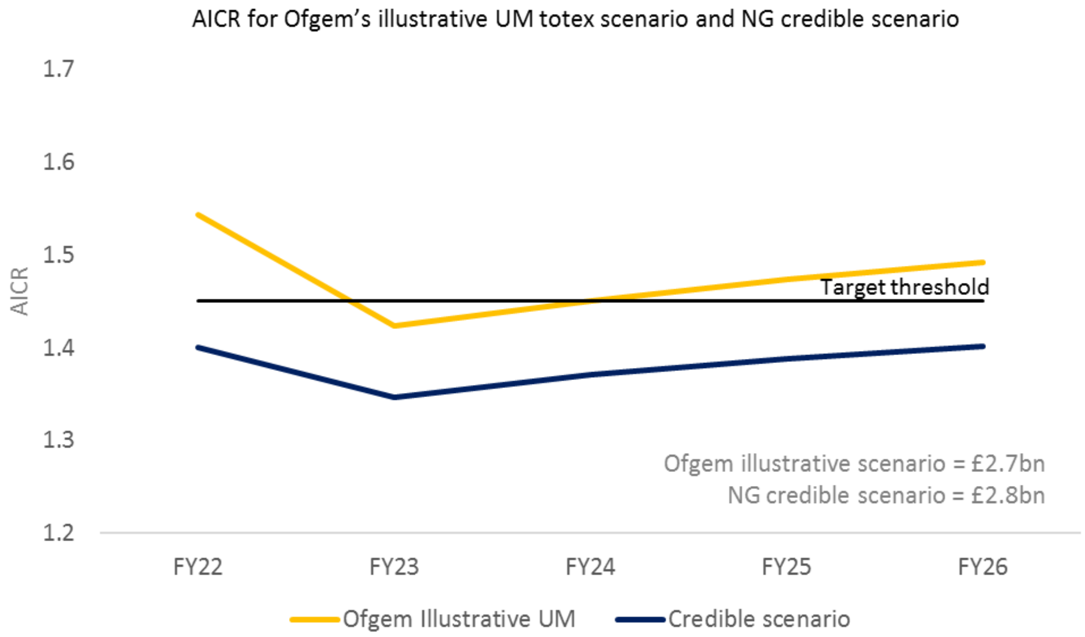
- A baseline totex plan consistent with Draft Determination documents (£1.6bn);
- Exclusion of cashflows from the outperformance wedge;
- Inclusion of the impacts of the BPI penalty;
- A single fixed capitalisation rate policy set on baseline funding; and
- A depreciation policy, so that for RAV additions from 2002 to 2021 the depreciation is on a 45-year, sum of digit basis, with a 30-year asset life assumed for RIIO-2 additions.

Wholesale use of UMs to manage uncertainty creates a significant cashflow risk and in practice may reduce network agility and responsiveness

Ofgem's illustrative totex scenario of £2.7bn adds £0.5bn to the Licence Model baseline of £2.2bn to stress test financeability against higher totex levels outturning. This stress testing is welcome, but the illustrative case is missing £0.1bn of load related totex that has already been triggered. We therefore would model at least £2.8bn and use this figure for a credible totex scenario from this point on in this response. This scenario is credible – even before any reversal of DD efficiency or volume cuts - because it is based on totex from our business plan Ofgem have moved to be subject to an uncertainty mechanism and load investment already triggered by a customer signal.

Using this credible scenario adjusts the AICR credit metric trajectory in the period. Whilst Ofgem's £2.7bn scenario shows AICR above minimum Baa1 thresholds, updating to the credible scenario brings AICR below 1.4 in FY23 and FY24. This shows UM driven totex could cause a financeability issue and our totex is effectively constrained at £2.7bn by the DD.

Figure 13: AICR trend for Ofgem's illustrative totex scenario (£2.7bn) and our credible scenario (£2.8bn)



From DD it is clear that Ofgem's approach to managing uncertainty has been to move funding to an uncertainty mechanism which determines allowances during the price control. Whilst there are benefits for a more flexible and adaptive type of regulation to respond to uncertainty, for this approach to be effective will require Ofgem to be agile and respond quickly if we are to avoid delays to investment in essential infrastructure. Yet, the design of the proposed mechanisms does not provide this agility and responsiveness.

Under the DD framework, outputs and therefore allowances and revenues are adjusted in the year of delivery through volume driver mechanisms or only when allowances are determined at re-opener windows for specified types of investment.

Table 14 Totex investment and timing of revenue recovery mechanisms

£m		FY22	FY23	FY24	FY25	FY26	Total
Baseline	Spend / Ex ante allowance	334	355	333	306	302	
Re-openers	Spend	115	185	296	320	268	
	Revenue			Assume FY24 re-opener submission		Revenues updated through allowance determination of £1185m	
Totex spend summary		334	355	333	306	571	1899
		115	185	296	320	0	916

funded in line with spend — spend at risk, prior to funding determination

Note

Prior to determination of allowances, revenues are based on the difference between allowances and spend after application of the Totex Incentive Mechanism.

The presentation in Table 14 is based on a high level but not unreasonable assumption that all re-openers will be submitted in FY24 with a further two-year lag until allowances are determined and full revenue recovery can take place. The timing will vary according to the re-opener window specific to a particular project and the agreed touchpoint that needs to be achieved in order for the submission to be made and assessed. As an example, we show a single major project to demonstrate the significant spend at risk under the current uncertainty mechanism design and if forecasting were not adopted for re-opener mechanisms.

Figure 14 timing of revenue recovery mechanism for King's Lynn subsidence project

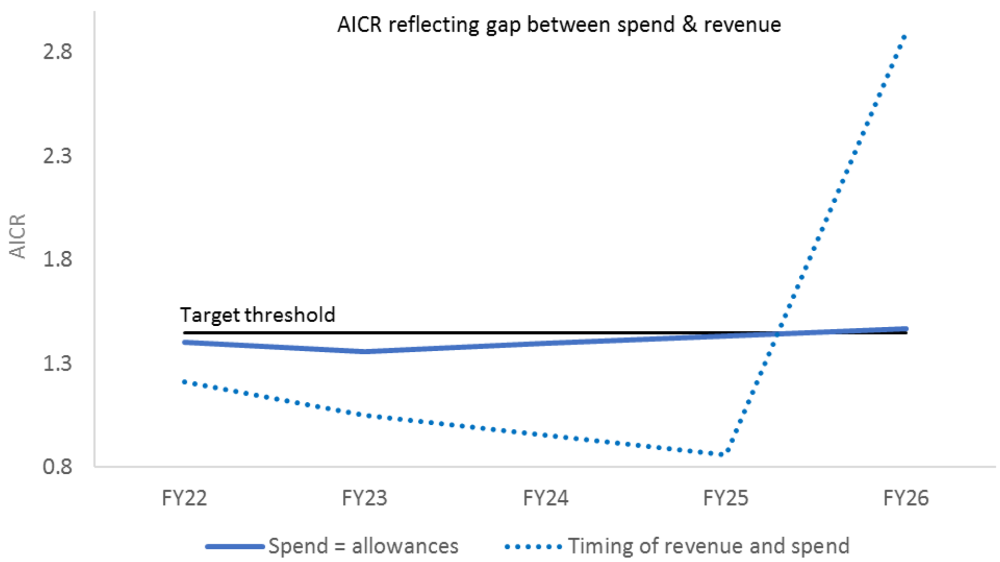
King's Lynn subsidence timing of	2021			2022				2023				2024				2025
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Baseline funds	0.3	0.3	0.3	0.3												
Totex spend	0.1	0.1	0.1	0.1	1.2	1.2	1.2	1.2	5.9	5.9	5.9	5.9	0.4	0.4	0.4	0.4
Ofgem approval touchpoints						Agreed stage gate/ submit re-opener		Assume re-opener approval		Allowance included in Annual Iteration Process			Allowances recovered including catch-up adjustment			

spend at risk, prior to funding determination   funded in line with spend

This analysis shows a two-year gap between the end of baseline funding and the timing of revenue received.

Factoring in the time lags between investment and revenue recovery shows that spend in line with the illustrative scenario (£2.8bn totex) means the network falls to Baa3 throughout much of the period. A significant increase then occurs in the final year when mechanisms do allow revenue recovery, creating huge volatility in revenues and therefore customer charges. Based on current assumptions, this would trigger a 40% increase in customer charges in the final year of RIIO-2.

Figure 15 AICR trend including gap between spend and revenue under uncertainty mechanisms



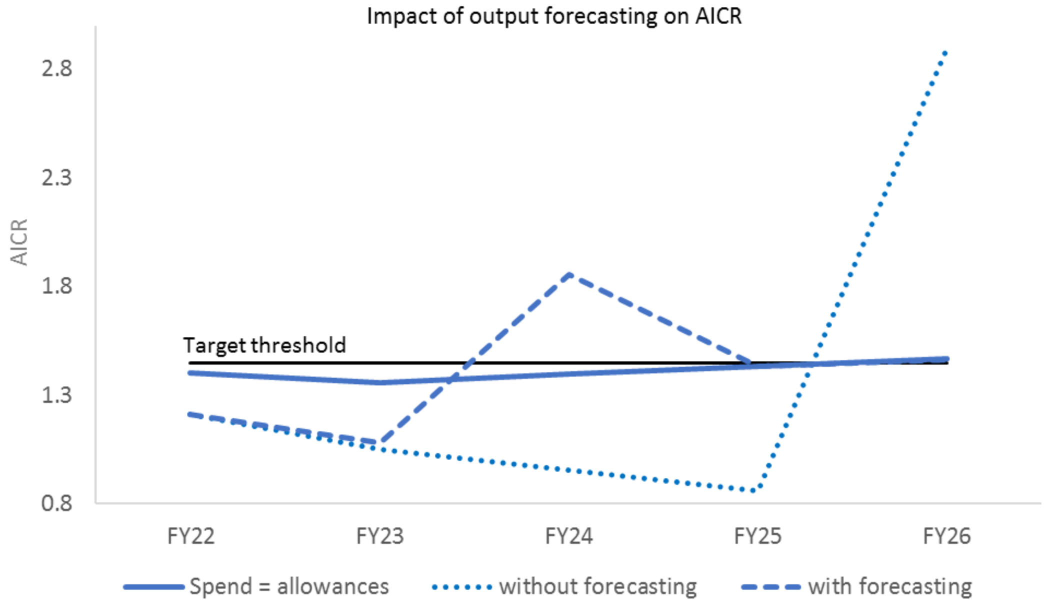
Forecasting of outputs improves financeability but only if re-openers are in scope

Recognising the cashflow risk from a delay in funding received through uncertainty mechanisms, we are supportive of Ofgem's proposal to include a forecasting mechanism which allows revenue to be calculated on an expected output position. Allowing timing of spend and revenue to be more closely aligned improves financeability and the AICR profile.

However, the ability to close any credit metric gaps created from revenue timing is dependent on the type of mechanism funding the totex. Ofgem's proposal is to restrict the scope to forecasting of outputs covered by volume driver UMs. There are no such UMs for GT. This means we would not be able to forecast revenue for any of the £1.2bn of UM funded totex above DD baseline in the credible totex scenario of £2.8bn until Ofgem have determined allowances through the reopeners. As shown in Table 14 this would mean the gap of up to 4 years between spend and revenue for items subject to reopeners in year 3, would remain and credit metrics would not change.

Even if forecasting of outputs was to apply to reopeners, the impact on credit metrics would not bring the trajectory above the minimum Baa1 / BBB+ threshold for the first two years of the RIIO-2 period.

Figure 16 AICR trend showing impact forecasting of outputs on reopeners could have on the metrics



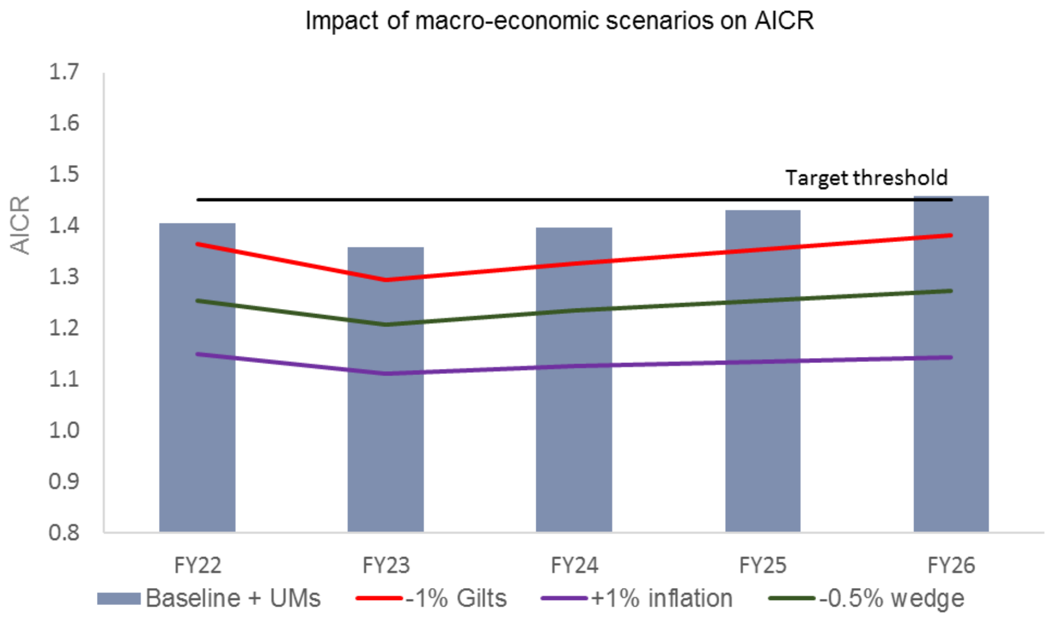
More generally, we welcome framework changes which allow revenues to be more closely linked to output delivery. It reduces volatility of revenue and charges for our customers whilst somewhat mitigating the related spend at risk. However, this approach must not be used as an alternative to setting an appropriately calibrated financial package. Even with application of forecasting of outputs, we see from the profile that gaps cannot be mitigated entirely and a constraint at the start of the price control remains which should be addressed through a package which funds work required both efficiently and fairly.

The framework offers limited financial resilience for the network to respond to energy transition in a volatile economic environment

So far in this response, we have focused on stress testing financeability with different totex scenarios and gaps between spend and revenue. There are equally sensitivities around economic factors that need to be considered.

Even assuming a best-case scenario where spend equals allowances, our analysis shows we do not have the headroom to absorb any cost over runs or expected increased volatility in the macroeconomic environment driven by economic events such as Brexit and the COVID-19 lockdown. Figure 17 below shows the AICR metric trajectory under sensitivities of a 1% reduction in gilts, 1% increase in CPI inflation and 0.5% drop in the wedge between RPI and CPI.

Figure 17: macroeconomic sensitivity analysis to assess implications against our credible plan

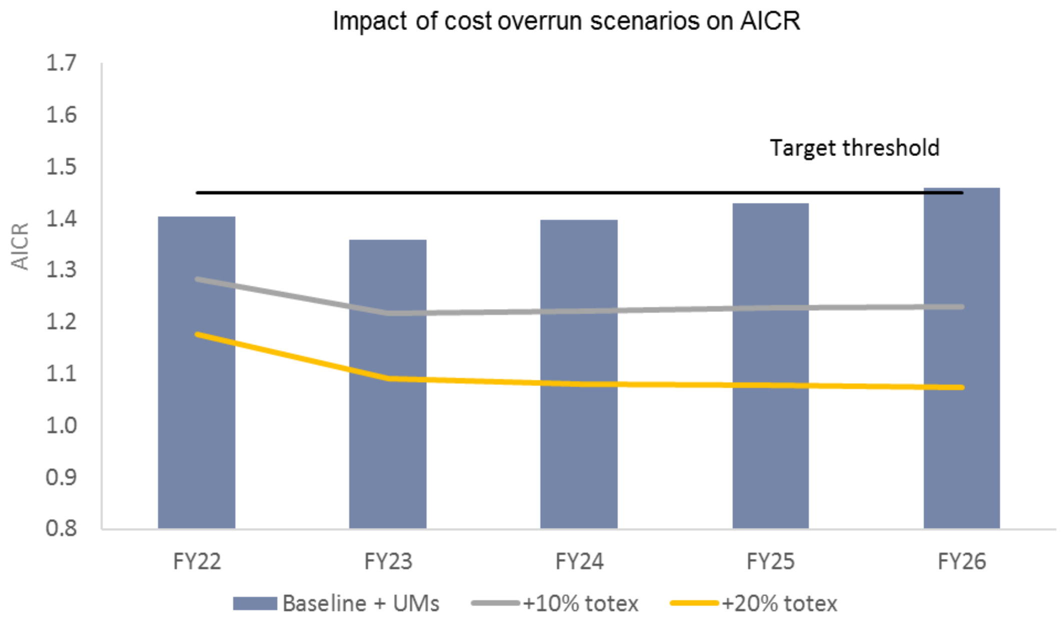


The financial package is particularly sensitive to movement in the macroeconomic environment where a 1% change in the inflation rate means AICR deteriorates to the Baa2 threshold for much of the period. It is lower still when we assess the implications against a more credible totex plan where just a 1% drop in the gilts rate drops the network below the target threshold.

We note Ofgem have concerns with our approach for our inflation stress test. Ofgem in their application assumes the majority of nominal debt in the notional company has been contractually fixed and will not change in either outturn inflation or inflation expectations. However, in doing so Ofgem underestimates the correlation between the fixed rate for new debt and inflation and minimises the risk created by the mismatch between earning a real return in revenues and incurring costs which are typically linked to inflation.

We appreciate that indexing the price control provides protection against general price inflation but it is unlikely that we can absorb all of the risk, and certainly not immediately, therefore headroom in the metrics is still required to be able to ensure ongoing resilience of the network.

Figure 18: cost overrun sensitivity analysis to assess implications against our credible plan



To assess the impacts of plausible cost over runs we run scenarios in line with Ofgem's stress tests, i.e. +10% overspend and +20% overspend. With a 10% overspend scenario, AICR drops to the minimum Baa2 threshold throughout the period and further to Baa3 if a 20% overspend is assumed, plausible given the level of challenge embedded into Ofgem's plans.

Ofgem's package does not give due consideration to the needs of equity investors

Ofgem's focus on debt investors fails to consider the investor proposition despite the need for additional equity injections to align gearing to what has been deemed notionally efficient. While debt investors typically focus on credit metrics, equity investors focus on dividends and growth. Our business plan provided extensive evidence to explain why a stable dividend policy is important to our investors. A 5% dividend yield is in line with investor expectations but Ofgem's package cannot support this level of return to shareholders with AICR falling further below the target threshold.

Figure 19: 5% dividend yield assessment

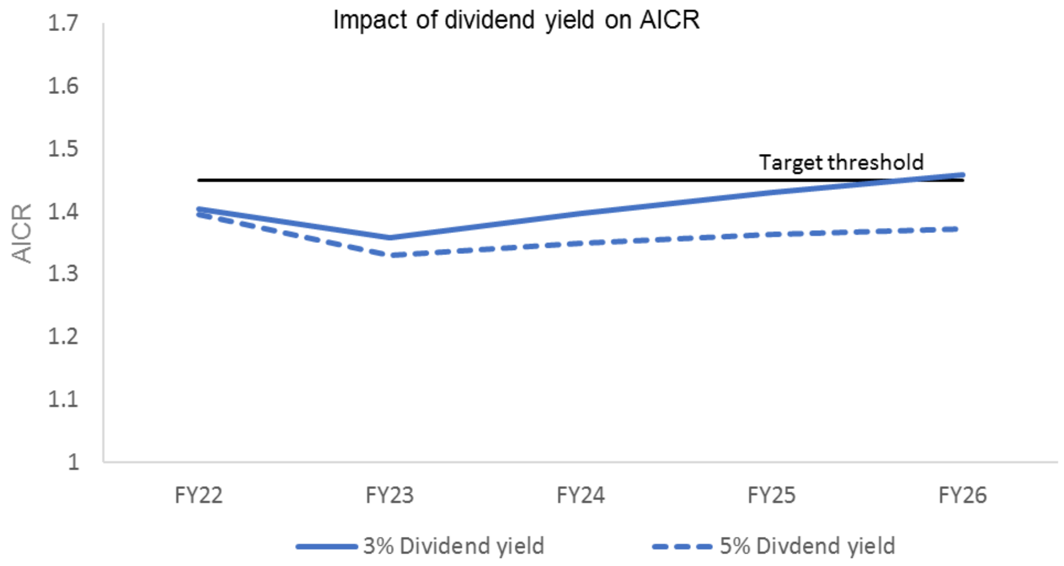
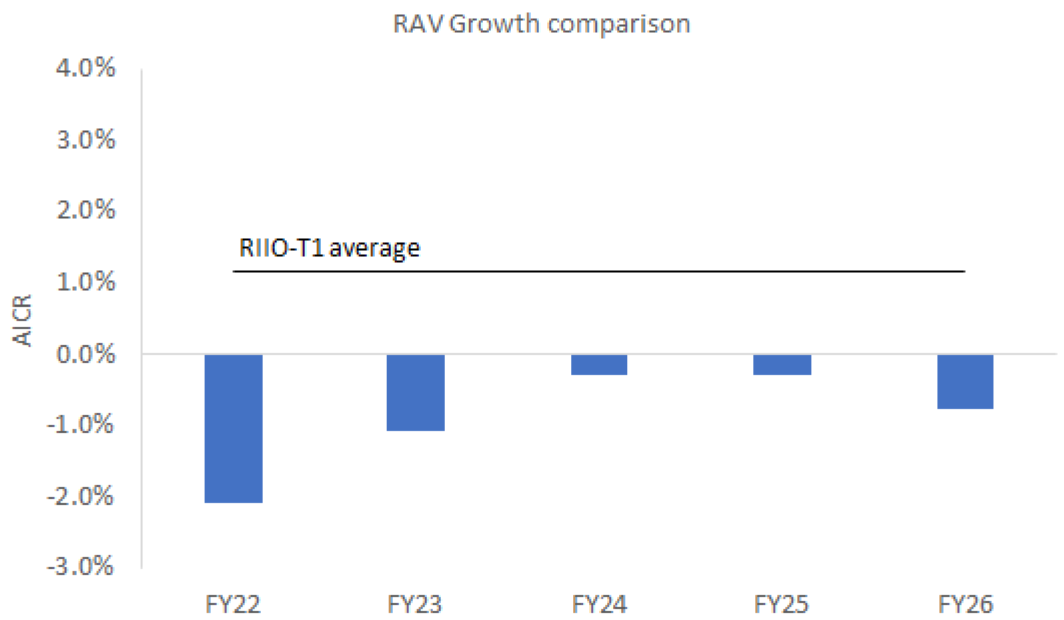


Figure 20: Real RAV Growth for credible totex scenarios in RIIO-T2 compared to RIIO-T1 average

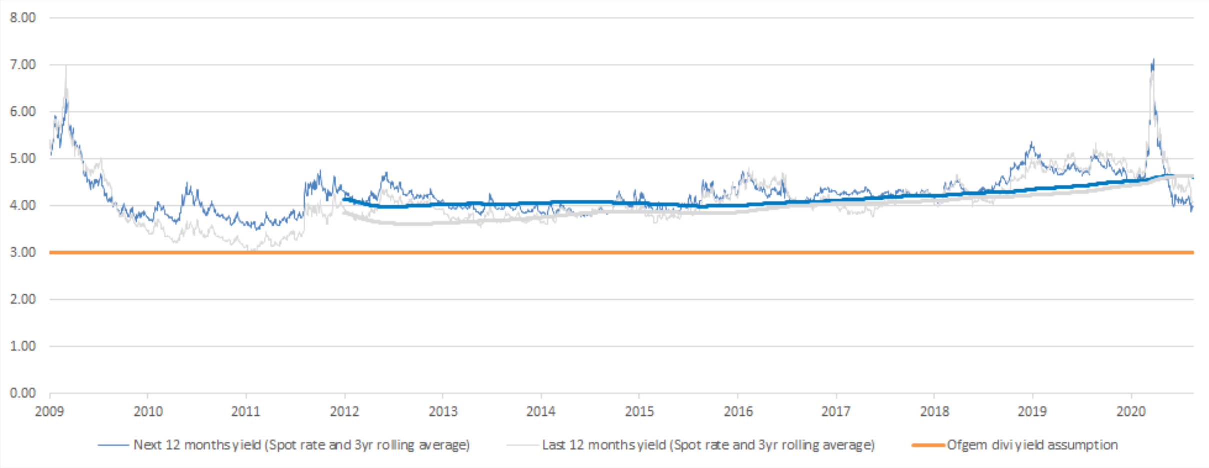
Ofgem agree with us that shareholder value is a combination of dividend yield and RAV growth, but for the baseline + UMs case underlying is lower than seen over RIIO-T1 and negative in real terms.



This means that dividends will be even more important to shareholders than they have been, yet Ofgem's assessment only factors in a dividend yield of 3%. This is below the average dividend yield of the utility sector of 5% since 2009 and even below the average yield of the FTSE 100 which is 4% since 2009.

Ofgem state that their 3% dividend yield assumption is based on the FTSE 100 yield. However, there is no evidence for this statement, and we have been unable to re-create these figures. The chart below contains dividend yield data from Bloomberg and shows the "next twelve-month" dividend yield expectation and "last 12 months" yields over the last 11 years. There is only one period where the yields become close to Ofgem's 3% assumption. Apart from that figures are above the assumption, averaging 4% pa.

Figure 21: Historic FTSE 100 dividend yields



More fundamentally, the minimum equity investors should expect from a price control is to be able to achieve the allowed equity return. However, as we set out in the "Unachievable allowed equity return" section of the Summary narrative at the start of this document, this is not possible for RIIO-2. We would have to deliver an unprecedented 25% saving in allowed totex to achieve the allowed equity return given the level of downside added by the DD at the start of the RIIO-2 period.

There are potential remedies that can help with debt and equity financeability

There are remedies that could help this position. We have already set out above that the use of forecasting of outputs for reopeners would close some of the cashflow risk. In addition, Ofgem have moved multiple investments out of baseline funding and into the scope of in period reopeners. For many of the reopener uncertainty mechanisms, the need for a level of expenditure has been established by Ofgem. Uncertainty only exists in the precise scope or cost of activities. In these circumstances, the cashflow risk can be reduced by aligning our baseline allowances with likely spend and adjusting from that position in the period.

We proposed this as part of our business plan, and it would have the added benefit of making customer charges more stable in the period, smoothing out a potential 40% increase in charges in the last year. We recognise that placing the entire £1.2bn of potential UM investment in the baseline could create variability in charges if the investment was found not to be required in the period. However, a sizeable proportion, potentially half of this value, would provide a more balanced approach to setting customer charges in the period.

These solutions would not address all the issues, but they would close a substantial proportion of the cashflow gap. The remainder would be closed by taking a more balanced assessment of the allowed equity return evidence. Ofgem may assess that the notional gearing could be reduced given the credit metric shortfall, as with the Electricity Transmission sector. As the notional gearing has already dropped from 62.5% in RIIO-1 to 60%, there is limited scope for this and we would not supportive of material movement (see the response to FQ13 for more detail), however if the equity return and broader policies had been tested robustly (which in our view they have not yet around equity return at least) a small change could be justified to improve short-term credit metrics.

Additionally, from an equity perspective, Ofgem need to reflect the higher dividend yields based on FTSE100 and utility sector benchmarks in the financeability assessment and ensure that the allowed equity return is achievable.

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

We broadly agree with the use of 60% as the notional gearing for NGG. However, we do not agree with Ofgem's test which adjusts notional gearing to address financeability concerns through achieving a presupposed level of financial headroom. The determination of notional gearing should reflect the risk profile of the business with market data providing a useful sense check.

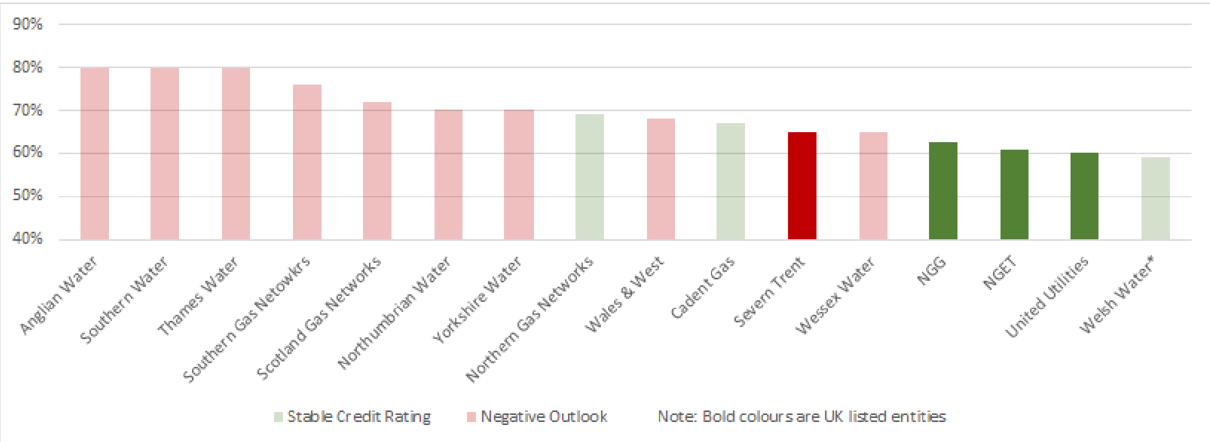
Ofgem's gearing test (set out on page 108) suggests that notional gearing should move up or down depending only on the level of headroom within credit metric analysis. Whilst financeability is a cross check to the WACC levels set out in the price control, it is not the sole determinant of an efficient level of gearing. The concept of market data benchmarks is referenced in the test and potentially bounds any movements., However, the source data and reference points for these benchmarks are not specified creating significant uncertainty over the thresholds that Ofgem would consider appropriate. There are limits to how large a change in gearing should and can be made in any company, notional or not and it would be beneficial for Ofgem to set out where it sees the bounds for the energy sector.

Precedent from previous price controls is also important when considering gearing. To change notional gearing significantly from one price control to the next suggests there is instability in the financial framework which should be avoided. Practically, large swings (more than 5%) in notional gearing would signify fundamental shifts in the risk or nature of the underlying business which is not a characteristic either debt or equity investors would expect from energy network companies which invest in long-term assets and strategies in a stable regulatory environment.

In RIIO-1, the notional gearing of NGG was set at 62.5% by Ofgem. A reduction in gearing to 60% is consistent with our view that annual capex will increase over RIIO-2 compared with that of RIIO-1. Marginal movements from one price control to another, such as this, are not necessarily an issue as long as the costs of change are funded. This is the case in DD where the proposed movement is 2.5% for NGG and necessary equity issuance costs are proposed to be funded by revenue

A notional gearing of 60% also remains within the range exhibited in market data which shows energy networks and broader utilities have financial structures which are geared between 60% and 80% on a RAV basis, the higher end of this spectrum tending to apply to companies who are on negative outlook or who have been subject to downgrades.

Figure 22 Regulatory gearing and credit rating outlook across the Gas Distribution, Transmission and Water sectors



*Not for profit
Note: Gas Distribution and Water sector gearing taken from Moody's sector reports, NGG and NGET gearing taken from March 2019 stats, adjusted for dividend payments made in July 2019.

Although we are broadly comfortable with 60% notional gearing for NGG, the move to 60% notional gearing for both Gas Distribution and Gas Transmission should be considered with some caution. In RIIO-1, the margin between Gas Transmission gearing of 60% and Gas Distribution Gearing of 62.5% was consistent with the long-held view that the transmission network was of greater risk than distribution. There is still evidence that the risk differential between the distribution and transmission sectors exists. We set this out in response to FQ6. We note that determining notional gearing levels is not an exact science but there does not seem to be much evidence for aligning the risk and therefore gearing of the two sectors.

On balance, given the marginal change in notional gearing for NGG and change in depreciation policy for RIIO-2, we are comfortable that the operations can support this higher equity proportion. This does not come lightly given the low returns in RIIO-2 and if there were further moves downwards in the gearing (e.g. for financeability purposes) this may raise additional concerns that would need to be considered. It may also break the principle of not moving notional gearing materially one price control to the next.

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

The COVID-19 pandemic has created additional risks that need to be assessed and taken into account when setting allowed returns and when assessing financeability. The items we draw Ofgem’s attention to are the impact on investor’s expected market return from investors and the impact on asset betas. We will also continue to monitor and assess the framework and cashflow risks of COVID-19 as the situation develops over the coming months.

Impact on investor’s expected market return from investors

The impact of COVID-19 on investment manager forecasts has already been noted in our response to question FQ8 above. Recent long-term capital market assumptions from investment managers (supported by comments from the Bank of England) since the pandemic outbreak show that in their view the required returns on equity in the UK (i.e. TMR) are currently considered to have increased significantly as a result of the COVID-19 outbreak. The implication is that the return on equity for network companies calculated via the CAPM will have increased correspondingly.

Ofgem have proposed use of investment manager forecasts as a cross-check both in the SSMD and in DD, and on this basis Ofgem should take account of these recent much higher forecasts than older, out-of-date publications from investment managers. However, we consider TMR is better seen as a long-term measure estimated from properly calculated long-run average returns (cross-checked to properly formulated DDM estimates), and so would not necessarily advocate attaching too much weight to these recent forecast values made across a relatively short time window at this stage. It is also possible that these investment manager views may revert to pre-pandemic levels in the coming months or year. However, what the updated forecasts in recent months do demonstrate is that there is a heightened risk of low confidence, significant volatility and uncertainty in financial markets over the months ahead. It is highly likely that the future path of the outbreak will remain uncertain for some months if not years, and therefore in the light of Ofgem’s financing duty, as a minimum the potential for markedly higher required returns on equities (TMR) as indicated by these recent forecasts needs to be recognised by Ofgem when setting allowed returns for RIIO-T2.

Impact on asset beta estimates

Whilst it is still not clear whether the market impacts of COVID-19 are temporary or mark a structural break there are a number of observations that can be made about the market impacts.

The impact of COVID19 which has seen utilities react more like cyclicals relative to previous crises where utilities have been seen as safe-haven assets. This time safe haven assets appear to be tech stocks. This has led to beta estimates for utilities in UK, EU and US to increase, with the most marked increases being in the US. Frontier note that *"The precise drivers of this change are of course unknown, but they may include a perception that utilities may be at greater risk of bad debt in the present climate should the economy slow and there be pronounced job losses."*[135]

It is therefore clear that the impact of COVID19 is different from that for previous crises, such as the GFC, in that utilities are not seen as a safe haven assets. However, the more significant increase in US asset betas has impacted the NG decomposition analysis. Frontier conclude:

"It is clear from the table that the US companies in our sample are the most affected by a large jump in beta estimates due to COVID19. This has an important bearing on our NG decomposition results, as we rely on a robust estimate for the US activities to decompose our NG beta. We therefore caution the direct use of the latest result in this particular estimate, and defer our attention more to the pre-COVID19 period"[136]

Corporation tax questions

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

We agree the proposal to pursue Option A, subject to our comments below on the additional protections. A notional tax allowance has worked well in RIIO-1 and it is important to retain an incentive for licensees to manage their tax affairs efficiently in the best interest of customers and to appropriately negotiate with HMRC.

In addition, we welcome the suggestion in 10.6 of the RIIO-2 Draft Determinations – Core Document that incentives will be funded post tax but request Ofgem explicitly confirms that tax on all incentive income earned by licensees will be fully funded for the RIIO-T2 period.

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

Roll forward of capital allowance balances

[135] "Estimating beta for RIIO-2", Frontier Economics, September 2020, Section 5.2
[136] "Estimating beta for RIIO-2", Frontier Economics, September 2020, Section 5.2

We recommend that pool balances are reset to actual at the beginning of RIIO-2 as this is consistent with the approach adopted for RIIO-T1 and will ensure that the notional measure of capital allowances for RIIO-2 better reflects the actual capital allowances that we expect to receive. It will also ensure a consistency with the approach being taken for the ESO.

Changing the basis for setting opening pool balances between price controls will create permanent differences in capital allowances over the life of an asset, potentially disadvantaging customers or licensees both within this and future price controls.

Re-setting the opening pool balances to actual in accordance with the intention set out in RIIO-1[137] will also help eliminate reconciliation differences between notional and actual tax costs.

Variable values in the RIIO-2 PCFM

We agree with the principle of making allocation and allowance rates variables within the RIIO T2 PCFM as this should help eliminate reconciliation differences between notional and actual tax costs[138].

However, as the CT600 will not be available when the Annual Iteration Process is completed for the preceding regulatory year, there will be a three year lag before actual CT600 pool allocations are reflected in revenues received (e.g. actual pool allocations for FY22 will only be reflected in the PCFM in FY24, which will then impact the Adjustment amount collected in FY25). The revenue adjustments for FY24, 25 and 26 would all fall into periods beyond T2. This contrasts with OFGEM's aim that making the capital allowance allocation rates variable values will "enable updates during the price control."

If the allocation rates used in setting the initial tax allowance are sensible at an individual licensee level, we wouldn`t expect any in period true-ups to CT600 pool allocations to be material and, if they were, an explanation would be required in the Tax Reconciliation narrative. Given the time lag challenges noted above, Ofgem may want to consider whether allowing variable pool allocation rates achieves their aims in this area. In our view, it would be simpler to retain company specific non-variable allocation rates but with a specific Tax Reconciliation narrative requirement.

If allocations remain variable, Ofgem should provide guidance on the process for updating allocation rates and the trigger for doing so such that, at the very least, the timings of any revenue adjustments are clear.

Intangible Assets

We note that intangible assets have not been separated out within the PCFM. As previously highlighted, intangible assets are not allocated to capital allowances pools and instead tax relief is given for the amount amortised through the statutory account's amortisation charge. Intangible assets are typically amortised, and hence relief is given for tax purposes, over a shorter period than would be the case through any capital allowance pool. As well as potentially disadvantaging customers, it creates another variance between actual tax and notional tax and, hence, a residual tax difference in the Tax Reconciliation.

To ensure the tax allowance is more reflective of a Licensee's actual tax charge and to reduce reconciliation differences, we recommend that an additional "intangible assets pool" is added to the PCFM. This could be set up with a variable value amortisation rate so that Licensees

[137] https://www.ofgem.gov.uk/ofgem-publications/53602/4riiot1fpfinancedec12.pdf, para 6.27

[138] Our CT600 capital allowance claims are based on a review of individual projects and, as such, are not driven from a regulatory asset class categorisation. If pool balances were reset to actual and if allocation percentages were updated on a two-year lag basis to better reflect allocations in the CT600, we would still expect there to be some level of reconciliation difference between the notional and actual capital allowance balances.

can reflect the mix of amortisation rates that should be applied. We would be happy to work with Ofgem to incorporate this into the new PCFM model.

In the absence of such a pool we request that Ofgem provide guidance as to how intangible assets should be treated within the PCFM (i.e. which capital allowance pool these should be allocated to).

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

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

We agree that a materiality threshold should be incorporated into the tax reconciliation process to allow for immaterial unexplained differences.

We also agree that the deadband is an appropriate measure for the materiality threshold as it reflects the relative size of the business being undertaken. Although guidance needs to be provided in how to calculate the deadband and the figures to be used in the calculation.

As noted below, in order to better link the tax reconciliation process to the Tax Review process, we recommend that the materiality threshold adopted for the Tax Reconciliation process mirrors the threshold adopted for the first trigger condition under the Tax Review.

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

Tax Trigger Mechanism

We support the retention of a Tax Trigger for those items that cannot be incorporated as variable values with the Annual Iteration Process, including specifically what under RIIO-1 are referred to as the Type B tax trigger events. This is important in ensuring that a mechanism is retained to address changes in tax legislation or accounting practice that materially impact on a Licensee’s actual tax liability.

We also agree with the proposal to replace the macro with variable rates as discussed above.

Tax Clawback Mechanism

In relation to the Tax Clawback mechanism, we would request that the policy objectives and rational underpinning the Tax Clawback be revisited as part of the wider RIIO-2 package. Given the introduction of the Tax review it is not clear that there is merit in retaining a separate mechanism.

If the Tax Clawback is to be retained, given the relatively long-term nature of the debt used by Licensees to support their activities, we agree it is appropriate to adopt Ofgem’s proposal for the notional gearing levels used for the gearing level test to be gradually reduced over the period of the price control.

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

In our view, the Tax Review should only be triggered where it is proportionate, and a Licensee should not be left uncertain several years after an accounting period as to whether a review will be opened.

The first trigger event is where there are material, unexplained differences between the notional allowance and actual tax costs, which have not been adequately addressed in the commentary to the reconciliation.

We agree this is an appropriate trigger event, but to be proportionate, an appropriate materiality threshold is required. In our view, this should be the same materiality threshold used for the Tax Reconciliation. It would be odd if a variance was small enough to be an acceptable unexplained difference for reconciliation purposes but large enough to be capable of triggering a Tax Review.

To provide certainty to licensees, as material unexplained differences will be reviewed as part of the Tax Reconciliation process, we recommend that Ofgem's ability to trigger a Tax Review on this first trigger lapses on or around the closing out of the Tax Reconciliation process.

The second and third triggers are where (i) Ofgem is notified of a valid concern by the licensee, any other licensee or other stakeholders and (ii) where a licensee undergoes a change in ownership, or a material change in circumstances that is likely to affect their tax costs.

It is not clear to us what concern these triggers tackle that wouldn't be tackled by the first trigger. If the purpose of the Tax Review is to enable Ofgem to establish whether the notional tax allowance remains appropriate and the test for measuring appropriateness is a comparison of actual tax costs to the notional tax allowance, the first trigger should be all Ofgem requires. Consequently, in our view, a single trigger Tax Review would be sufficient for Ofgem to achieve its policy aim.

If the second and third triggers are deemed necessary, to provide certainty to licensees, Ofgem's ability to trigger a tax review should lapse 24 months after the end of the accounting period in which the trigger event occurs (which we additionally note would be after the reconciliation cycle for that period).

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

We have submitted drafting recommendations on the proposed Board Assurance Statement through the Licence Drafting Working Group and, as such, we refer you to our comments included within the Issues Log in relation to the Board Assurance Statement.

Drafting recommendations aside, our key comment is on timing. As noted in the Finance Annex, due to the timing of CT600 submissions, a tax reconciliation will need to be performed with a one-year lag (i.e. a reconciliation for the 2021/2022 year will be submitted by companies in July 2023).

The Board Assurance Statement, as currently drafted, asks for a certification for the preceding regulatory year to be provided no later than 31 July. The CT600 will not have been submitted by this point so the Board Assurance Statement will need to be completed on the same one-year time lag required for the Tax Reconciliation process.

The Board Assurance Statement also requests copies of the Senior Accounting Officer ('SAO') submissions. The DAG requirements already cover the licensees' internal assurance processes and controls which is essentially what the SAO certification covers. Requesting the SAO certification is therefore an unnecessary duplication. As such, the requirement to submit SAO certificates should be removed.

Return adjustment mechanism questions

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

We are supportive in principle of Ofgem's proposal for a symmetrical return adjustment mechanism (RAM). Having a clearly defined mechanism that adjusts returns outside of anticipated range at time of setting control, whether due to changes in external factors or undetected error or information asymmetry benefits both consumers and networks. A symmetrical mechanism meets Ofgem's stated intent for this mechanism to protect against unexpected returns, which can be either upside or downside in nature.

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

We are supportive of the proposed single RoRE threshold level, as it meets the principle of simple upfront design of mechanism that will avoid perverse incentives on networks. We agree that 300bps represents a reasonable threshold in balancing the risks of consumers paying too much or too little for networks, with the need to allow a range of network returns so that well performing networks are differentiated from less well performing networks.

In line with our previous responses to Sector Specific Methodology we are supportive of the threshold being applied to RoRE excluding tax and financial performance as this is closer to a measure of true operational performance in which networks and consumers would expect to share the risk and reward. It is not in the best interests of consumers to bear the risk of financing and tax performance.

Notwithstanding our position that an outperformance wedge adjustment should not be included in the calculation of CoE, Ofgem should centre the threshold on the unadjusted base cost of equity to avoid interactions with performance wedge adjustments.

We support the retention of risk/reward sharing outside of the RoRE threshold as this retains incentivisation on networks to continue to act to mitigate downside risks to the benefit of consumers. The proposed 50% adjustment meets the criteria of transparency and seems reasonably calibrated.

The threshold for returns adjustments should allow for differentiation of performance across networks and remain effective in protecting consumers and networks for unexpected events that lead to unanticipated returns.

We agree that, under the proposed package, the proposed 300bps threshold would be unlikely to be triggered based on anticipated performance. Ofgem's modelled maximum and minimum RoRE ranges fall between +170bps and -200bps and therefore the proposed threshold would not interaction with TIM and ODI incentives enabling differentiation of performance across network companies

However, elsewhere in our response we raise concerns about the overall balance of package put forward by Ofgem and how it limits incentivisation, particularly in the Transmission sector, and illustrate this by comparison with the recent PR19 determination for the water sector. Expected returns for the PR19 deal range between +335bps to -581bps (based on expected Totex and ODI performance). We have proposed that Ofgem remedy the low incentivisation, which should give rise to a higher RoRE range, comparable to the water sector. This should not necessitate a change to the RAM ranges.

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

We are supportive of Ofgem's proposal to implement RAM assessment following RIIO-2 closeout. An annual or pre-close out process would likely be based on an incorrect view of performance without appropriate adjustments to RoRE for timing differences and other enduring value adjustments. Making the returns adjustment assessment following the close out of RIIO-2 issues reduces this risk, although there may still be some items that distort RoRE. To maintain the transparency of this mechanism Ofgem should use licence drafting process to consult with networks on a clearly defined process for the operation of this mechanism.

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

We support the proposal to move from RPI to a consumer price based index (either CPI or CPIH), understanding that RPI has been subject to criticism from some parties in recent years and that this places pressure on the regulator to seek an alternative index from a legitimacy point of view. However, as Ofgem has previously noted, it remains the case that any change in inflation measure should be NPV neutral from an investor's perspective when seen over the long-term.

In DD, Ofgem said (at paragraphs 9.2 to 9.3) that in our Business Plans NGET and NGG propose CPIH rather than CPI as a basis for RIIO-2. However, our business plans did not actually specifically consider whether CPI or CPIH would be the preferred index, although we did note that if future price controls starting with RIIO-2 are to be linked to CPIH, as Ofgem have proposed, an estimate of expected future CPIH inflation will be needed when setting the price control, for example when deflating the iBoxx index when setting the cost of debt, and in estimating the RFR. As there are still no widely accepted reputable values of expected future CPIH, the nominal iBoxx index values will need to be deflated using values that are based on the expected level of future CPI, although the CPI values used should be adjusted to take account of the anticipated difference between CPI and CPIH. We are not, though, aware of any reputable or widely accepted values of the difference between CPI and CPIH either, suggesting it will be difficult to set RIIO-2 on a basis relative to CPIH in a rigorously defensible way. Ofgem appear to be relying simply on being able to make the assumption that CPIH will not systematically be higher or lower than CPI.

In considering objectively whether the price control should be set relative to CPI or CPIH, an important factor to consider is which index is favoured by financiers and the government as this will impact on both the understanding and acceptance of the index. Although CPIH may be the official inflation target, the more favoured index in financial markets is CPI, although this may change for future rounds of price controls after RIIO-2.

As noted above, Ofgem's proposals in the DD rely on an implicit assumption that CPI and CPIH will, on average be equal. This creates further risk and uncertainty, as CPI and CPIH are not generally equal, and differentials can persist for many months or years. This issue arises in many elements of the proposed price control. Ofgem are in substance proposing a CPI linked price control in many respects (e.g. the elements of the WACC), but a CPIH-linked control in others (e.g. RAV indexation), where this mismatch obviously creates risk. Consistent with our past consultation responses, therefore, we remain of the view that it would be better, simpler and more transparent to use CPI throughout, i.e. to set and index price controls to CPI rather than CPIH until such time as CPIH is more firmly established in the economy, for example, until there are reliable CPIH forecasts, and until CPIH-referenced financial instruments have become well-established in the market.

In relation to what CPI forecasts should be assumed when setting the price control, these CPI values should, in the interests of transparency, be based on independent published values, such as from the OBR.

The transition to CPIH accelerates cashflows in the short-term which temporarily supports financial metrics in the RIIO-2 and RIIO-3 periods. As noted above, the transition is required to be NPV neutral from an investor perspective. Therefore, the initial positive movement in cashflows from the inflation transition will subsequently show a negative variance. As a result, the use of CPIH transition which supports Ofgem's proposed package for RIIO-2 will have a detrimental impact on the long-term sustainability of the network.

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

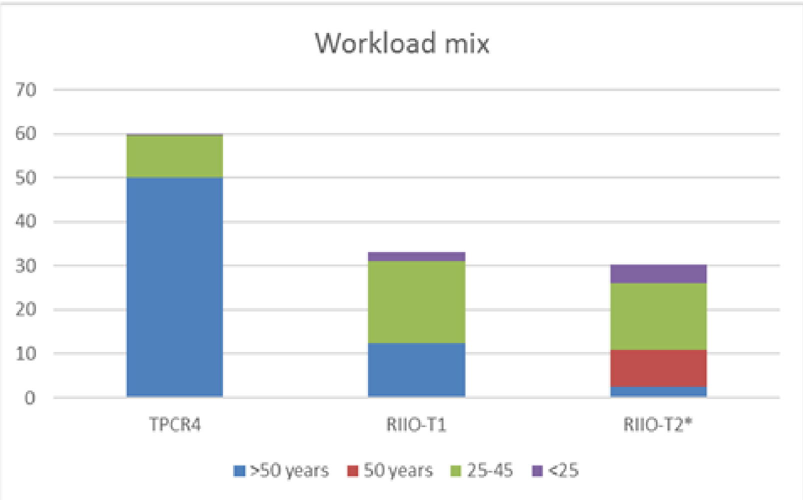
We agree with the adoption of sum of digits depreciation for the Gas Transmission Owner RAV additions, and the alignment of the policy with Gas Distribution to restate this adjustment to 2002. We do not however agree that asset lives should remain at 45 years for RIIO-2 additions. An asset life of 30 years for RIIO-2 additions would be more appropriate as this aligns with the average technical lives of the investments we will be making in the RIIO-2 period.

We support adoption of a sum of digits deprecation profile for Gas Transmission Owner RAV additions to create alignment of underlying assumptions of the future role of the gas network across the sector. This is important to de-risk potential RAV stranding given the latest FES20 data shows 3 of the 4 overall gas demand scenarios show a declining trend as we head towards 2030. We also agree it is appropriate to recover backlog depreciation over 20 years from the start of RIIO-2 to minimise revenue volatility and charging implications. We recognise and agree with the symmetry between the length of the backdating adjustment and the period to recover the backlog over.

However, Ofgem's depreciation policy needs to go further to be reflective of required investment during the RIIO-2 period. Regulatory asset lives underpinning the depreciation profile should reflect the expected economic and technical life of assets for the individual periods of investment. In doing so, depreciation charges reflect the benefit consumers derive from the network services they receive; and the charges have regard to intergenerational fairness of the associated charge.

The graph below shows how the workload mix for investment spend has changed over the most recent price control periods and RIIO-2. The size of the column aligns to the average technical asset life for the investments in the period, so the average life of assets in TPCR4 was 60 years, for RIIO-1 it was just over 30 years and for RIIO-2 it is expected to be 30 years. In RIIO-2, the significant proportion of investment will be to maintain the existing network (asset health) and to ensure it continues to be compliant with changing environmental legislation (compressor investment). The asset life is therefore now lower than 45 years which was appropriate when pipeline work to meet customer exit and entry requirements was a more significant proportion of the plan.

Figure 23: Workload mix over RIIO-2 and previous price control periods



In our December business plan, we proposed an asset life of 25 years for RIIO-T2 additions. However, taking into account changes in the asset mix from DD and feedback from Ofgem that they believe our compressors have a technical life in excess of 25 years, we calculate that a reasonable average technical asset life - and therefore regulatory asset life - for RIIO-T2 additions is 30 years.

We appreciate that reducing asset lives will have an impact on revenues increasing consumer bills in the short term, which we assess to be an additional 10p on the average annual consumer bill during the RIIO-2 period. The increase is appropriate however to ensure charges are reflective of the consumer base using our networks service and to ensure limited intergeneration charging by reflecting the correct asset life.

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

We do not agree with Ofgem's policy which proposes two annual ex ante capitalisation rates, one for the spend included in baseline allowances and the second for capex intensive uncertainty mechanisms (a split capitalisation rate). We also do not agree with setting an annual rate which is exactly in line with the related opex / capex mix as implemented in Ofgem's financial model.

We appreciate there could be benefits in applying a split capitalisation rate to address concerns over the uncertainty in opex / capex proportions of investment programmes. However, the approach presupposes that the opex / capex proportion of uncertainty mechanism expenditure can be forecast at the start of the period, despite the inherent high uncertainty in RIIO-2, and we do not think this approach is appropriate for the RIIO-T2 control given related financeability constraints.

The reason why uncertainty mechanisms have been used extensively in Ofgem's DD, is there are inherent uncertainties in the level of totex to deliver customer outputs in RIIO-1. This covers both the level of totex, and the mix between opex and capex activities. The split capitalisation approach assumes the opex / capex mix can be assessed at the start of the price control before the uncertainty mechanisms have been triggered, which is not the case. In previous price controls this may have been easier as the vast majority of mechanisms related to capex investments, however in RIIO-2 Ofgem have linked opex costs to the uncertainty mechanism through introducing an opex escalator mechanism. Ofgem has also introduced several ex-post true ups, the operation of which could well alter the opex / capex mix of our allowances significantly.

Separate to this uncertainty, as we have outlined in our response to FQ12, our financial position is significantly constrained under Ofgem's package and we do not have any headroom to fund totex levels higher than the baseline. Adopting a fixed capitalisation rate with the opex / capex split reflective of our baseline allowances will provide a natural financeability hedge against higher totex levels outturning and give some financial support for short term metrics through increased revenues when the higher totex scenarios outturn.

Table 15 below shows the revenue impacts of the Baseline + UMs and credible scenario of totex, using the fixed capitalisation and spit capitalisation policies. This shows higher revenue under fixed capitalisation, which would give benefit in the short term credit metrics.

Table 15 The impact of a fixed capitalisation rate on revenue, forecasting of outputs applied

Total Revenue (£m)	FY22	FY23	FY24	FY25	FY26
Fixed Capitalisation Rate	1051.9	1063.5	1229.7	1166.0	1133.2
Split Capitalisation Rate	1016.4	1013.9	1066.5	1064.2	1071.1

In their financial model, Ofgem use a different capitalisation rate in every year of the plan, aligning fast / slow revenue with the opex / capex mix of expenditure in the year. In practice, this will never happen in any year given the inherent uncertainty and related changes in totex through the period. An annual capitalisation rate can be useful in addressing uneven capex profiles to ensure that fast money is directly related to the opex spend in any individual year. However, setting an annual rate to ensure this alignment creates other issues that far outweigh any perceived benefits.

An annual rate will inevitably add complexity with different rates adopted for different years. Furthermore, there are the unintended consequences which could distort network expenditure decisions by creating the opportunity to time spend (delay or bring forward) to coincide with years when the rate is beneficial to the network.

In theory, these weaknesses can be addressed by setting the annual rates as an ex-ante value followed by an ex-post true-up adjustment, but this then creates other practical difficulties. The issue of when and how to adjust the agreed capitalisation rate is complex as the volume and timing of capex is amended through agreed mechanisms during – and up to two years after - the RIIO control. More fundamentally, the introduction of an ex-post adjustment to capitalisation rates weakens the equalisation of incentives between opex and capex, a key principle of RIIO which has incentivised networks to consider the most cost-effective solution regardless of expenditure type.

We support a capitalisation policy which reflects the nature of expenditure expected over the price control, but Ofgem's approach is too restrictive in attempting to achieve these outcomes and in doing so creates other more fundamental issues which should be avoided.

Our proposal is to set a fixed average over the price control period based on the opex / capex split in our baseline allowances. This maintains the precedent set in RIIO-1 and ensures that the framework remains consistent with a totex-based regime.

In summary, we support a policy which uses an average of the opex/capex split in the baseline plan to set a single capitalisation rate over the price control period. This is the most transparent method through which we can reflect expected expenditure whilst retaining the benefit of a totex approach and offering some financial support in a financially constrained environment.

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

We do not support an ex-post adjustment to reflect outturn proportions for capex and opex as we see limited benefits in re-opening methods that were used to determine regulated charges for a previous regulatory period. Whilst we agree that accuracy is an important objective so too are simplicity and efficiency. With RIIO-2 mechanisms not likely to be finalised until up to two years after the RIIO-2 period ends, this approach would add a level of unnecessary complexity. However, our biggest concern, as outlined in our response to FQ24, is the weakening of the equalisation of capex and opex exposures in the totex mechanism, a mechanism which has created a step change in the efficiency delivered in RIIO-1.

If rates were to be updated ex-post for the RIIO-2 period we would expect the same principles to be applied for RIIO-1 close out.

Based on Regulatory Reporting Pack (RRP) 2020, this would mean recovery of £141m of revenues as opex has out-turned to be a more significant proportion of our T1 expenditure than was anticipated at the time the capitalisation rate was set.

	Funded Totex		
	TO Certain	TO Uncertain	SO
Opex	841	49	517
Capex	1202	188	306
Totex	2043	237	823
T1 Cap Rate	64%	90%	37%
Fast Money	727	24	516
Opex to Fast Money Variance	114	26	2

RAV opening balance questions

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

We agree that the closing balance for RIIO-1 should be used as the opening balance for RIIO-2. The RAV is a key building block of the price control review being the value upon which the companies earn a return and receive a depreciation allowance. Continuation of the RAV from RIIO-1 to RIIO-2 is therefore a significant factor in driving investor certainty and confidence in the regulatory framework.

The RIIO-1 closing RAV balance can only be finalised after conclusion of the RIIO-1 framework in March 2021 and therefore prior to this date should be subject to estimation. Our views on the estimation of RAV balances and RIIO-1 close out items are included in our responses to FQ26 and FQ28, respectively.

On transitioning from the RIIO-1 to the RIIO-2 framework, there is a change in both the price base and the inflation measure applied in indexation of the RAV. The move of the closing RIIO-1 RAV balance from a real, RPI-stripped 2009/2010 price base value to a real, CPIH-stripped 2018/2019 price base RIIO-2 opening balance is intended to be net present value neutral[139]. To delivery transparency around the neutrality of the change in inflation index, close out adjustments applied to the RIIO-1 RAV and the conversion to the opening RIIO-2 RAV should be explicitly shown within Ofgem's Price Control Financial Model and any supporting documents, such as legacy calculations.

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

In principle, we agree with the use of estimated opening RIIO-2 RAV balance until finalisation of the closing RIIO-1 RAV balances. We further consider the appropriate estimations to include within the provisional opening RIIO-2 RAV balance within our answer to FQ28.

On moving from an estimated to a finalised opening RAV balance, there will be a change in return and depreciation allowance which will revise revenues for all regulatory years up to the year in which the balance is finalised. The impact of this catch up adjustment for prior year revenues within a single regulatory year may have considerable impact in terms of both the effect on consumer bills and on the financeability of the notional and actual company. Estimation of the RIIO-1 balance should limit the magnitude of this catch-up adjustment and therefore the single year impact on revenue.

The RIIO-2 opening RAV balance included in the Ofgem Business Plan Financial Models with the Finance Annex of our December 2019 RIIO-2 Business Plan submission and also the Draft Determinations – RIIO ET2/GT2 Licence Model are already based on an estimated value. The outputs, allowances and totex spend for each year of the RIIO-2 price control will only be finalised once the final Regulatory Reporting Pack submissions have been completed in 2021 and any associated close out adjustments proposed and agreed. The RAV values included within our December 2019 RIIO-2 Business Plan submission and, as noted by Ofgem in paragraph 11.9 and 11.10 of the RIIO-2 Draft Determinations - Finance Annex were based on the 2019/2020 and 2020/2021 totex and allowance forecasts from the RIIO-1 Regulatory Financial Performance Reporting pack submission made to Ofgem in July 2019. We expect Ofgem to update the closing RIIO-1 RAV balance through the Final Determination publication in line with the August 2020 submission of the RIIO-1 Regulatory Financial Reporting pack to reflect the latest view of RAV additions and depreciation.

[139] RIIO-2 Sector Specific Methodology Annex – Finance, Ofgem, 18 December 2018, page 67, para 6.13

In line with our response to FQ28, the only additional adjustments, not captured through the Annual Iteration Process and therefore the MOD value, which should be reflected in the RIIO-2 opening RAV balance are those where a value can reasonably be forecast and a mechanism exists through which the RAV can be adjusted. This encompasses asset disposal and the true-up of excluded services.

The estimated RIIO-2 RAV opening balance and any adjustments or estimates should be explicitly defined within Final Determinations to provide transparency over the value neutrality of the transition between RIIO price control periods.

RIIO-1 close-out questions

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

The adjustments outlined by Ofgem in the Finance Annex are:

- adjustments to the final RIIO-1 PCFM which feed into the RIIO-2 Price Control Financial Model (PCFM), such as the opening RAV balance, depreciation allowances and opening capital allowance pool values;
- adjustments which impact RIIO-2 allowances revenues, such as two-year lagged incentives; and
- adjustments impacting allowed revenue and RAV, such as the MODt value for the first two years of RIIO-2.

We agree that these three categories capture the adjustments that will be required to finalise the values associated with RIIO-1 price control which inform the RIIO-2 regulatory framework. There is a significant amount of work required to arrive at these adjustments and to determine their impact on RIIO-2 RAV and revenues requiring development of the RIIO-2 licence, development and population of the RIIO-2 PCFM and PCFM Handbook and agreement of the mechanism and values through which the adjustments can be made

Ofgem has made clear their intent to incorporate all variable values and resulting revenue streams which make up allowed revenue within an extended PCFM. However, the structure and functionality of this financial model is yet to be shared. We have communicated our concern to Ofgem (both as an individual licensee and through the Energy Networks Association) that there is considerable work required by Ofgem to manage the risk of transitioning to a new model and to ensure revenues and the interface between the RIIO-1 and RIIO-2 price control periods are treated correctly. It is essential that Ofgem's models are robust, well understood and are consistent with licence drafting prior to them being used by Ofgem for managing the price control.

We consider each of the adjustments in turn.

Adjustments to the final RIIO-1 PCFM which update the PCFM for RIIO-2

Adjustments will be required to finalise the RIIO-1 PCFM. The final PCFM will need to include totex and allowance values based on the outputs and performance delivered in 2019/2020 and 2020/2021. These values will impact the closing RAV and capital allowance pool balances which will be carried forward to RIIO-2. As the RAV balance is dependent on a number of close out mechanisms and values, neither which of which will be determined until after the commencement of the RIIO-2 period, we agree with Ofgem's policy that estimated balances should be used until these final adjustments are determined. Our responses to FQ26 and FQ28 further set out our views on the use of estimated RAV balances.

Ofgem also give depreciation allowance as a specific example of an area requiring adjustment within this category. We agree that RIIO-1 depreciation allowances will update through adjustment of the RAV additions but do not consider there to be further adjustments required for NGGT. We agree with Ofgem's methodology for the revision of the regulatory depreciation profile from straight line to sum of digits phasing for RIIO-1 additions. This does not result in a change to the RIIO-1 RAV depreciation profile but is instead recovered through an adjustment to the RAV over a 20-year period commencing at the start of RIIO-2.

Adjustments that impact RIIO-2 allowed revenues

We agree with Ofgem that adjustments to revenue which fall outside of the PCFM form a separate category of adjustments. These items will require specific terms within the RIIO-2 licence in order that the revenues streams can be accounted for within RIIO-2 allowed revenues. The application of the time value of money to these terms is further considered within our responses to FQ31, FQ32 and FQ33. Our view is that given the items relate to RIIO-1, the same methodologies and calculations as set out in the RIIO-1 NGG licence should be applied with the weighted average cost of capital applied to revenue streams with a delay between the earning and receipt of the income or cost. It is typically revenues and costs subject to a two-year lag which will fall within the category including:

- true-up of 2019/2020 and 2020/2021 ex ante values of Pass Through items, including Business Rates, Licence Fees, Policing costs and Independent Systems Adjustments;
- the k correction factor; and
- income and costs earned through non-totex incentives.

Adjustments to allowed revenue and RAV

We agree that there will need to be adjustments to RAV and revenue, how this will be enacted in practice will depend on the individual item.

The MODt values relating to the RIIO-1 framework but impacting RIIO-2 revenues will require adjustments to both allowed revenue and RAV. MODt will reflect only those elements of the RIIO-1 framework for which there is a mechanism to adjust to RIIO-1 Price Control Financial Model. The RIIO-1 Regulatory Reporting process and Annual Iteration Process are the mechanism by which the MODt value is calculated and directed.

However, currently the RIIO-1 Price Control Financial Model does not contain the functionality required to calculate MODt relating to the final two years of RIIO-1 which are then lagged by two years to impact revenues in 2021/2022 and 2022/2023. In addition, the Price Control Financial Model, which is currently under development for RIIO-2, will require the capability to incorporate the MODt terms relating to RIIO-1 output delivery and performance.

There are further close out adjustments for which values and mechanisms are yet to be determined which will also impact the RIIO-2 allowed revenue and RAV values. These are not contained within the MODt calculations and will require separate calculation. We have already proposed to Ofgem, through the Licence Drafting Workshops which have taken place between Ofgem and networks during 2020, that a legacy workbook such as that put in place for the start of RIIO-1, is required to calculate and formally record the values agreed for the close out adjustments.

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

We agree that the use of estimated values for close out adjustments until the RIIO-1 price control is finalised is appropriate where there is an agreed mechanism in place for the adjustment and there are appropriate forecasts estimates available.

We are engaging with Ofgem outside of the process to develop the RIIO-2 framework to consider the various RIIO-1 close out adjustments for NGG. These RIIO-1 close out values will inform the RIIO-2 revenues and therefore the financeability of the actual company. However, the values cannot be finalised until completion of the RIIO-1 period in March 2021 and, in a number of areas, the mechanisms to enact these close out adjustments are yet to be proposed and agreed.

As stated in our response to FQ26, on finalisation of the RIIO-1 price control, there will be a revision to allowed revenues for all regulatory years up to the year in which the balance is finalised. The impact of this catch up adjustment for prior year revenues within a single regulatory year may have considerable impact in terms of both the effect on consumer bills and on the financeability of the notional and actual company. Estimation of the RIIO-1 balance should limit the magnitude of this catch-up adjustment and therefore the single year impact on revenue.

Estimation of close out adjustments should be limited to those items where discussions between the network and the regulatory have progressed to the extent that there is an agreed mechanism in place and where processes and information exist to provide a reasonable estimate of value. For items where there is significant variability or uncertainty (either due to lack of mechanism or unknown values), no estimates should be included until the RIIO-1 period has closed and determination of RIIO-1 close values has reached a conclusion.

Closeout adjustments qualifying for estimation are therefore required to meet the following criteria:

- forecasts are available through an existing reporting process; and
- either there is an agreed mechanism in place through which to make these adjustments, or
- agreed adjustment to RAV are made within the Regulatory Finance Performance Report (RFPR).

NGG close out adjustments which meet these criteria, include:

- non-totex incentives subject to a two-year lag;
- other two-year lagged items such as non-controllable opex true-up and the over/under recovery k correction factor;
- ISS allowances for additional sites (Peterborough and Huntingdon, Northern Gas Networks);
- return of ISS allowances NGG are due to return (NGG currently still has these allowances as they did not meet reopener threshold) £18.1m
- disposals as reporting in the Cost and Outputs Regulatory Reporting Pack.

MODt is excluded from the list of estimated adjustments as these values will be determined via the existing Regulatory Reporting and Annual Iteration Process. The outputs and performance delivered as reported through the Regulatory Reporting Packs and inclusion of directed values will be captured in the MOD values subject to the development of the appropriate functionality of the RIIO-1 and RIIO-2 Price Control Financial Models (reference FQ27).

The period over which the close out adjustments are made is not specifically covered within the DD proposals. The recovery period also requires consideration as part of the finalisation of the close out process.

We propose that the recovery period for RIIO-1 close out items adjusted through the legacy revenue term extends over the RIIO-2 and RIIO-3 price controls (assuming RIIO-3 to be of five years duration). This period aligns more closely with the precedent adopted in RIIO-1 where legacy revenue close-out adjustments were recovery through equal phasing over the eight years of the price control. An adjustment over two price control periods is also proportionate to the eight-year period over which the close out adjustments accrued. This approach is consistent with Ofgem's proposal for recovering the backlog depreciation (Draft Determinations - Finance Annex paragraph 10.12) which is based on the precedent set in RIIO-GD1 of smoothing charging volatility of the backlog adjustments. We note that the 20-year period for recovering backlog depreciation aligns with the period over which the value has accumulated which again is consistent with our proposed approach for phasing legacy revenue adjustments.

Disposal of assets questions

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

We agree that disposals should be netted-off against totex in the year in which disposals occur, in line with our previous stated in our response to Ofgem's Sector Specific Methodology Consultation[140].

The Draft Determinations - Finance Annex does not further define cash proceeds. As set out in our response to the Sector Specific Methodology Consultation, the adjustment to totex should be for cash proceeds net of tax. For RIIO-1, this reduction to totex additions for disposal proceeds (net of tax) will be made as part of RIIO-1 close out process. For RIIO-2, we agree that the adjustments should occur in the year in which the disposal is made to enable sharing the benefits with the consumer as soon as possible.

The adoption of this methodology is consistent with regulatory precedent within National Grid's current price control with legal settlements being categorised as negative totex and we note that this approach is followed by the Electricity Distribution Networks.

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

We do not agree with Ofgem's proposal to carry out a review where an asset is transferred to a [holding] company and then subsequently sold to a third party. Such a review is beyond the scope of the financial ring fence provisions that are applicable to the licence holder.

For intragroup transfers Ofgem has placed a licence obligation on the networks (Standard Special Condition A39. Indebtedness) that all transfers to other group companies are made on an arm's length basis, on normal commercial terms and in accordance with the payment condition specified in those conditions. In such cases, disposals require an independent valuation to demonstrate that best consideration is being obtained and that these licence obligations are satisfied. In practice, whenever there has been an intergroup transfer of land, National Grid has received external third-party valuations based on the Royal Institute of Chartered Surveyors (RICS) guidelines and we intend that this approach is continued.

This principle is applied to record the transaction in the accounting records when there has been a market transaction and the network has received monetary consideration for sale of scrap, arm's length transactions to a third party and for the value of insurance settlements received[141]. The intent of applying this principle to intragroup transactions is to replicate a transaction to an independent third party reflective of the market conditions and condition of

[140] National Grid's response to Ofgem's RIIO-2 sector specific methodology consultation – Finance, p88

[141] We set out the definition of net sales proceeds in our response to Ofgem's sector specific methodology consultation.
National Grid's response to Ofgem's RIIO-2 sector specific methodology consultation – Finance, p88
"The net sales proceeds are recorded which is the sales proceeds received from a disposal less the costs of disposal. Costs of sale are the incremental costs of achieving the sale including transaction costs (for example, legal fees, commissions, professional adviser's fees) and costs of getting the assets into a saleable condition (such as, site clearance costs, systems separation costs). Costs of disposal do not include finance costs or taxation."

the asset at the time of sale. Any subsequent onward sale of the asset by an affiliate of the licensee to an independent party would inevitably reflect the work done on the asset and the movement in market conditions in the intervening time. Neither of these factors are relevant to the terms of the original transfer by the licensee which will have had to satisfy the obligations of the indebtedness provisions of the licence. The terms of such a transaction is also beyond the scope of the financial ring fence provisions that are applicable to the licence holder.

We note that paragraph 11.36 of the Finance Annex references transfers to companies within the licensee group compared with FQ30 which is of narrower scope than transfers to holding companies. Our response covers the former, however, we request that Ofgem provide further clarity over the scope of its proposal policy.

Time value of money questions

We set out our views on the time value of money in our responses to FQ31, FQ32 and FQ33. We also refer Ofgem to a report prepared by First Economics[142] and submitted by the ENA with which our responses are aligned.

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

We do not agree with Ofgem's proposal to apply one interest rate to revisions to Price Control Financial Model (PCFM) inputs and charging errors as we do not agree that a short-term cost of debt rate is applicable to all prior year adjustments.

Ofgem has set out three types of revenue true-ups:

- historical revisions to PCFM inputs, such as totex spend and allowances;
- earned income adjustments, such as that derived from non-totex incentive performance; and
- charging error corrections.

Under the RIIO-1 framework, a variety of time value of money adjustments are applied to these true-ups and, whilst we are in agreement that the appropriate interest rate should be considered as part of the price control development, we do not agree that simply aligning the rates is the correct course of action. The varied nature, timing, magnitude and therefore financing of the types of adjustment means that application of a short-term cost of debt time value of money is not appropriate in all cases.

Our assessment of the appropriate time value of money for each category is included in our response to FQ33.

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

We do not completely agree with the approach as there is an improvement than can be made. In addition, we do not agree with applying this approach to all revenue true ups as proposed in the DD. Our assessment of the appropriate time value of money for each category of revenue true up is included in our response to FQ33.

In terms of improvements to the approach we recommend that the market standard approach to convert London Inter Bank Offered Rate (LIBOR) and Sterling Overnight Interbank Average rate (SONIA) is used. The proposal uses the 3-year average spread between SONIA and 6-month LIBOR which is consistent with taking a 3-year average of the index but is inconsistent

[142] "RIIO-2 : Prior year adjustments", First Economics report prepared for the ENA, 12 August 2020

with the market standard methodology to convert LIBOR deals to SONIA. The market standard for derivatives is 5 years and the loan and bond markets will almost certainly adopt the same standard, irrespective of tenor. Adopting the market standard would provide additional transparency as this spread is now published on Bloomberg.

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

We do have reasons why the WACC remains a more appropriate time value of money adjustment for historical revisions to PCFM inputs, such as totex spend and allowances. We do however agree that under- and over-recoveries against the allowed revenue and earned income should roll forward at a benchmark interest rate.

Historical revisions to PCFM inputs, earned income and over- or under-recovery of allowed revenue currently encompass a wide range of adjustment mechanisms. These elements of the framework have developed over a number of price controls and there is justifiable regulatory precedent as to the distinction between different time value of money bases.

Revenue adjustment formulae have been in networks' licences since pre-RIIO price controls.

- The charging errors (or recovery correction) terms were introduced recognising that regulated companies would find it hard to set changes at the level needed to exactly meet the allowed revenue restriction due to within year changes in revenue and demand. The over- or under-collection of revenue is currently corrected with a lag of two years.
- The PCFM input revisions are a later addition to the regulatory framework and could arise for a variety of reasons. For example, the scope of a company's capital programme may not be fully known at the time of the price review or the regulator may not feel comfortable fixing the cost allowance for a known scheme. In each case, the regulator would, in effect, promise the company that it would "log up" incremental costs and provide for customers to pay for qualifying expenditures.
- The rationale for the time value of money applied to entitlements to collect revenue for additional investments that were not envisaged or allowed for in a regulator's base price controls stems from an aim to achieve net present value (NPV) neutrality.

As a general rule, the amounts that regulated companies were able to carry forward under such schemes included capitalised financing costs, where financing costs were set equal to the allowed cost of capital. Regulators recognised that the expense incurred by the company comprised not just the cash outlays but also the cost of financing their expenditures without any incoming revenue from customers. The allowance for financing costs effectively meant that the regulated firm was in the same position in value terms that it would have been in had the regulator been able to anticipate the firm's activity from the outset and provided upfront for the expenditure in its original price control determination. In effect, regulators took the view that the under- or over-recovery of revenues was equivalent to the deferment or advancement of cashflows that would otherwise have accrued to companies via the depreciation of their RAV. As the under- or over-recovery would be financed by incremental amounts of investor capital, regulators saw no reason to differentiate the cost of that capital from the cost of capital that they were using elsewhere in the price control.

Whilst the RIIO-2 framework may include a much broader set of adjustment mechanisms, the principles previously applied still hold true. The appropriate time value of money adjustment can therefore be assessed through consideration of the following questions:

- *Will the deployment of the prior year adjustment mechanism result in a change in the size of the investor capital base?*

Where companies need investors to finance deferments of revenues or could downsize amounts owed in the event of advancements of revenues, regulators have previously recognised that the capital requirements have a cost aligned to the regulated company's cost of capital, as applied to investor capital that was held within the RAV.

- *Does the prior year adjustment mechanism add to the potential variation in the regulated firm's cashflows?*

  Network companies were privatised with a finite amount of working capital factored into the initial RAV balance, specifically to allow them to manage mismatches in the timing of costs and revenues. Managing the under- and over-recovery of revenues was a business-as-usual activity. However, other prior year adjustment mechanisms present a greater variation in cashflows which cannot be managed within working capital.

- *Will the monetary value of the prior year adjustments be material?*

  Management of material under- or over- remuneration is unlikely to be managed through working capital. Such values constitute a call on the wider investor base, through a modification to the amount and profile of the company's borrowing programme and/or an adjustment to retained profit amounts and dividend payouts.

- *Will the prior year adjustments play out over a period of more than two years?*

  As in the previous consideration, if balances are being carried forward for periods that extend beyond two years, networks are less likely to manage the cashflows through working capital.

If the answer is positive to any of these questions, then we consider a cost of capital time value of money to be appropriate rather than application of a short-term debt rate.

We consider the three categories of adjustments listed by Ofgem against these considerations and the appropriate time value of money in turn.

Recovery of allowed revenue

These correction mechanisms have always provided for over- and under-recoveries to roll forward with interest. The interest rates have varied between price controls but have typically taken the form of a reference benchmark like the Bank of England base rate or LIBOR plus a percentage margin; the rationale being that regulated companies would maintain either an amount of working capital or a working capital bank facility to manage the relatively small variances in allowed vs collected revenues, with accompanying cost of bank interest.

We do not anticipate the magnitude of adjustment for over- and under-collection to change significantly from RIIO-1 to RIIO-2. Licencees' obligation to use best endeavours in ensuring that collected revenue does not exceed allowed revenue and the proposed introduction of forecasting outputs contribute to mitigating the magnitude of the adjustment. Also, we are not aware of any proposal to adjust to the timing of this mechanism beyond two years.

Therefore, we are in agreement with Ofgem that under- and over-recoveries against the allowed revenue should roll forward at a benchmark interest rate.

Variation of PCFM inputs

When a company is not permitted to recover its ultimate 'building block' revenue entitlement in full in year (for example, because a proportion of remuneration comes later via the Totex Incentive Mechanism or because it has to wait for a reopener), a company has to turn to investors to finance the mismatch between costs and revenues. The converse is also true when a company is permitted to collect more than its ultimate entitlement. Movements up and down in the investor capital base happen all the time in regulated industries for a myriad of reasons and it is illogical to single out prior year adjustments as a special case that somehow gives rise to smaller financing costs than all of the other calls that there can be on investors.

Financing costs in this case should be no different from the calculated cost of capital. CEPA in its July 2020 paper[143] for Ofgem makes the argument that "*the way Ofgem treats prior-year adjustments may entail a different, lower level of risk for companies compared to the main allowed cost of capital*". Specifically, CEPA states that "*By the time Ofgem comes to calculate prior-year adjustments, much of the risk in the company has already crystallised. Once calculated, the payment of a prior-year adjustment is effectively independent of the company's ongoing performance—that risk is in the past*".

This is not the case. The primary purpose of the allowed cost of capital is to ensure that investors are appropriately compensated for an exchange in which they finance expenditure upfront and are paid by customers in installments over a period of 45 years. When the RAV is rolled from one year to the next and provides a return to compensate investors for the delay in the reimbursement of their investment, the expenditure risk has already crystallised. The risk remains until investors have been fully compensated through return for the delay in the reimbursement of their investment. The risk in a change in compensation on the RAV and prior year adjustments cannot be differentiated and the capital that investors put into regulated businesses cannot be ring-fenced to different purposes. Instead, each increment of capital ought to be thought of as an expansion or a reduction of the total amount of capital that investors have at risk, with every element bearing identical risks around demand, costs and performance.

Therefore, we disagree with Ofgem's proposal and consider that a cost of capital time value of money should be applied to PCFM adjustments in line with the cost of capital that applies generally across the regulated business.

Earned income

Rewards and penalties that flow from performance metrics, such customer satisfaction, are regulatory constructs. Typically, in RIIO-1, earned income from these incentives has impacted allowed revenue with a two-year lag.

There is not, therefore, the same justification in conceptual terms for rolling accrued penalties and rewards up at the cost of capital. Nor is it appropriate to think in terms of interest rate for new deposits or borrowings building up during the regulatory lag. Instead, there is an inherent fungibility and even circularity to the choices that a regulator has. Because Ofgem chooses both the ODI calibration and the roll forward formula, it is perfectly reasonable to fix on a prior year adjustment approach that works in terms of administrative simplicity and to then calibrate the ODIs with the prior knowledge that payments will roll forward at different rates of interest.

On balance, given the lag in revenue is short (two years), we are therefore in agreement with Ofgem that under- and over-recoveries against the allowed revenue should roll forward at a benchmark interest rate.

We assume, based on discussions with Ofgem through the Licence Drafting Working Group, that the RIIO-2 PCFM will be expanded to beyond totex spend and allowances variable inputs and revenue flows to include all elements of allowed revenue. We have not yet had visibility of the structure or content of a draft RIIO-2 PCFM and highlight that this is not an exhaustive list of variables which may be adjusted in subsequent years and therefore be subject to a time value of money. As the licence and PCFM are developed further, additional areas of application are likely to come to light to which these principles should be applied.

[143] Prior-year adjustment uplifts, 9 July 2020, CEPA, p18

Revenue forecasting questions

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

We support Ofgem's proposals to allow totex spend, incentive performance and certain allowances which can be varied through uncertainty mechanisms to be amended during the price control for revenue forecasting purposes. However, we do not agree that allowances which are determined through the re-opener mechanism should be excluded, as detailed in our responses to FQ12 and FQ35.

Allowing revenues to be calculated on an expected outputs position is likely to significantly reduce volatility of revenue and charges for our customers, an area which has been consistently raised as a concern because of the impacts this has for their business. This approach will further improve how charges reflect our costs, but these benefits can only be realised if re-openers are included in the scope of the proposed revenue mechanism.

In addition, Ofgem proposes that legacy adjustments and RIIO-2 RAV opening values should be forecast. Our views on the proposal to forecast legacy adjustments and opening RAV balances are set out in our responses to FQ26 (estimation of RIIO-2 RAV opening balances) and FQ28 (use of estimated values for RIIO-1 closeout adjustments).

Ofgem also includes the forecasting of other revenue components such as DARTs, pass through and use-it-or-lose-it allowances. In principle, we support the forecasting of pass through and use-it-or -lose-it allowances, however, the DARTs revenue stream is more complex and needs careful consideration.

We assume that DARTs will continue to include legacy revenue adjustments, established pension deficit repair costs and directly remunerated services (DRS) revenues net of costs. If the RIIO-2 price control financial model is developed to include other elements, these will need to be separately assessed to establish whether forecasting of the variables is appropriate.

We consider the known components, as set out above, in turn.

As stated above, our view on the forecasting of **legacy revenue adjustments** is set out in our response to FQ28.

Established pension deficit repair costs are updated through the triennial review process and we see no justification that values determined through this process should be re-forecast in the interim.

As stated in our response to the SSMC, we appreciate that for **DRS** actual revenue earned, or costs incurred may differ from original forecasts and agree that it is beneficial to investigate true-up methodologies for sole use connections.

A true-up of these changes in post-vesting connection revenue can be captured within forecasting of post-vesting connections ensuring that a single till approach to revenue collection is maintained.

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

We do not agree with Ofgem's proposal to exclude re-opener allowances from forecasting. We reference our response to FQ12 which considers the financeability implications of failing to address the timing gap between investment in projects subject of re-openers and determination of allowances.

For completeness and in response to the request for examples or analysis of the potential materiality of this proposal, we reiterate the relevant portion of our answer to FQ12 within this response.

From DD, it is clear that Ofgem's approach to managing uncertainty has been to move funding to an uncertainty mechanism which determines allowances during the price control. Whilst there are benefits for a more flexible and adaptive type of regulation to respond to uncertainty, for this approach to be effective will require Ofgem to be agile and respond quickly if we are to avoid delays to investment in essential infrastructure. Yet, the design of the proposed mechanisms does not provide this agility and responsiveness.

The exclusion of re-opener allowances from the forecasting framework impacts adversely on both customer tariffs and the licensee's financeability.

Customer and consumer impacts

Under the current framework, outputs and therefore allowances and revenues are adjusted in the year of delivery through volume driver mechanisms or only when allowances are determined at re-opener windows for specified types of investment.

Table 16 Totex investment and timing of revenue recovery mechanisms

£m		FY22	FY23	FY24	FY25	FY26	Total
Baseline	Spend / Ex ante allowance	334	355	333	306	302	
Re-openers	Spend	115	185	296	320	268	
	Revenue			Assume FY24 re-opener submission		Revenues updated through allowance determination of £1185m	
Totex spend summary		334	355	333	306	571	1899
		115	185	296	320	0	916

funded in line with spend (grey) — spend at risk, prior to funding determination (red)

Note

Prior to determination of allowances, revenues are based on the difference between allowances and spend after application of the Totex Incentive Mechanism.

The presentation in Table 16 is based on a high level but not unreasonable assumption that all re-openers will be submitted in FY24 with a further two-year lag until allowances are determined and therefore until full revenue recovery can take place. The timing will vary according to the re-opener window specific to a particular project and the agreed touchpoint that needs to be achieved in order for the submission to be made and assessed. As an example, we show a single major project to demonstrate the significant spend at risk under the current uncertainty mechanism and if forecasting were not adopted for re-opener mechanisms.

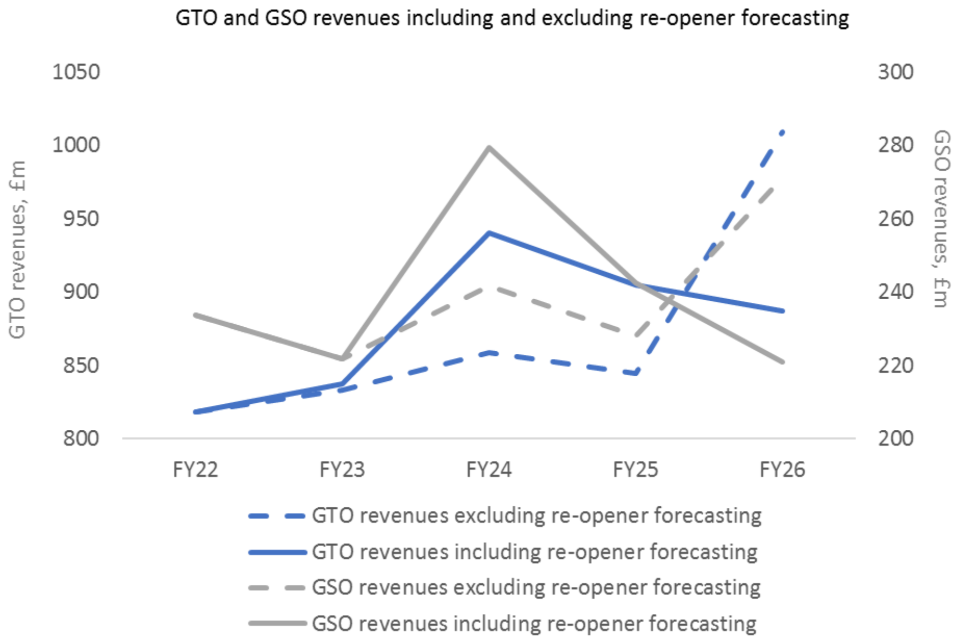
Table 17 Timing of revenue recovery mechanism for King's Lynn subsidence project

King's Lynn subsidence timing of	2021			2022				2023				2024				2025
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Baseline funds	0.3	0.3	0.3	0.3												
Totex spend	0.1	0.1	0.1	0.1	1.2	1.2	1.2	1.2	5.9	5.9	5.9	5.9	0.4	0.4	0.4	0.4
Ofgem approval touchpoints						Agreed stage gate/ submit re-opener		Assume re-opener approval		Allowance included in Annual Iteration Process			Allowances recovered including catch-up adjustment			

spend at risk, prior to funding determination | funded in line with spend

The impact on revenues is shown in Figure 24 for the baseline plus UM totex scenario (£2.8bn).

Figure 24 Revenues including and excluding re-opener forecasting (pre-inflation)

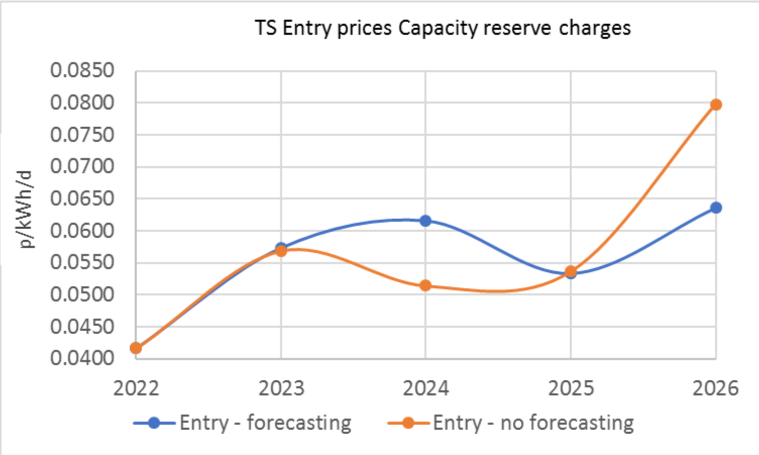


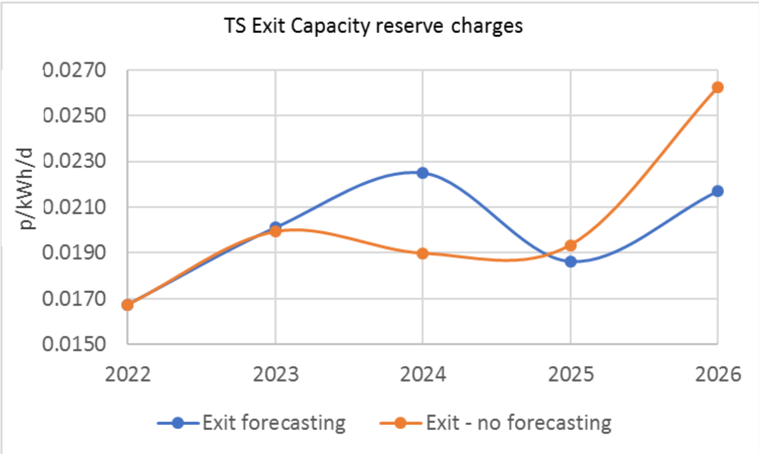
Ofgem's reliance solely on re-opener uncertainty mechanisms, means that their exclusion from forecasting has a limited impact compared with the current framework. We assume for the purposes of our analysis, that where forecasting does not apply, re-opener submissions are made in FY24 with allowances determined for inclusion in the Annual Iteration Process in FY25. There is a significant uplift in revenues in the final year of RIIO-2 as the allowances across the period are recognised resulting in a catch-up adjustment to revenues. These profiles are replicated in the charges.

The Transmission Services entry and exit capacity reserve charges (based on GTO revenues) are calculated on the following assumptions:

- demand continues at 2018/2019 levels;
- the UNC0678A charging methodology modification takes effect from October 2020; and
- entry capacity sold under existing contracts remains at 2021/2022 levels.

Figure 25 Charges including and excluding re-opener forecasting (pre-inflation)



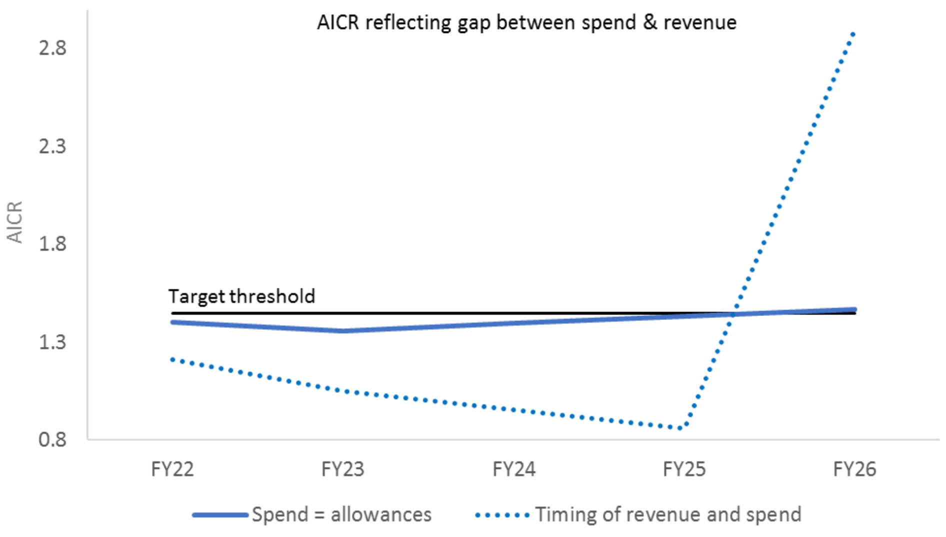


We acknowledge that some of the year on year movement in charges is due to the "saw-tooth" effect, which occurs as a result of the charging methodology and is understood by customers. However, even taking this into account, the increase in volatility of not forecasting re-openers is clear with a pre-inflation increase of 49% on entry and 36% on exit charges in the final year of the price control as compared with the previous year. This rises to above 50% post inflation. Forecasting re-openers dampens this increase by more than 20% limiting customer charge volatility across the period.

Financeability impacts

Factoring in the time lags between investment and revenue recovery shows that spend in line with the illustrative scenario (£2.8bn totex) means the network falls to Baa3 throughout much of the period. A significant increase then occurs in the final year when mechanisms do allow revenue recovery, creating huge volatility in revenues and therefore customer charges.

Figure 26: AICR trend including gap between spend and revenue under uncertainty mechanisms

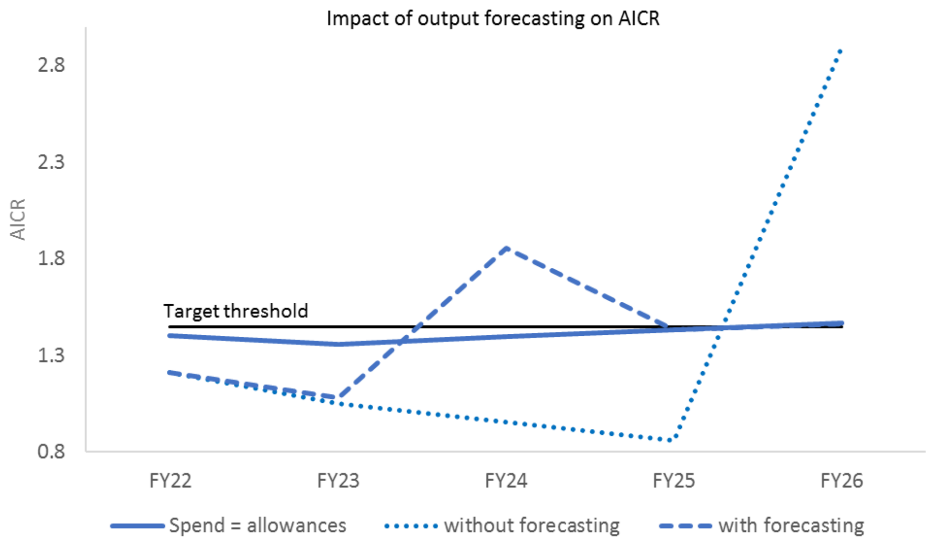


Forecasting of outputs improves financeability but only if re-openers are in scope

Recognising the cashflow risk from a delay in funding received through uncertainty mechanisms, we are supportive of Ofgem's proposal to include a forecasting mechanism which allows revenue to be calculated on an expected output position. Allowing timing of spend and revenue to be more closely aligned improves financeability, and the AICR profile.

However, the ability to close any credit metric gaps created from revenue timing is dependent on the type of mechanism funding the totex. Ofgem's proposal is to restrict the scope to forecasting of outputs covered by volume driver UMs. There are no such UMs for GT. This means we would not be able to forecast revenue for any of the £1.2bn of UM funded totex above DD baseline in the credible totex scenario of £2.8bn until Ofgem have determined allowances through the reopeners. As shown in Table 16 this would mean the gap of up to 5 years between spend and revenue for items subject to reopeners in year 3, would remain and credit metrics would not change.

Figure 27 AICR trend showing impact forecasting of outputs on reopeners could have on the metrics



In summary, we welcome forecasting of outputs but the proposal must go further and extend to re-opener allowances. This allows revenues to be more closely linked to output delivery. It reduces volatility of revenue and charges for our customers whilst somewhat mitigating the spend at risk.

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

Executive pay

We do not support the requirement for all licensees to report annually on executive pay and do not see the relevance of this to regulatory performance.

In several places, Ofgem refers to the equivalent requirement for listed companies as set out in the UK Corporate Governance Code, and the benefits these bring. However, there is no read across to subsidiary companies which would suggest that these should be subject to similar requirements, as the circumstances are inherently different. For example, as its owners, a listed company's shareholders have a legitimate and understandable need to understand the executive remuneration policy and how it links to performance and business strategy, and this is clearly in the interests of good governance. In the case of a subsidiary company, the equivalent 'ownership' interest in executive remuneration lies with the parent company. Ofgem's discussion fails to take these different circumstances into account, and so fails to demonstrate a benefit from the proposed additional disclosure requirements, in accordance with the principle of good regulation and as set out in the Electricity and Gas Acts, including that regulatory intervention should be proportionate and targeted only at cases in which action is needed.

Dividends

We do not support additional reporting on dividend policies. Requiring networks to provide additional reporting on dividend policies could needlessly place further constraints on management's ability to flexibly deliver a strong balance sheet to support investment and deliver an appropriate level of distributions to shareholders.

In relation to the setting of price controls, Ofgem's focus should be to have regard for the financeability of the notional company. In relation to the 'actual' company, Ofgem already has in place a comprehensive set of financial ringfence conditions in network companies' licences to protect the interests of consumers, and the additional information now being provided to Ofgem through the RFPR process provides Ofgem with an additional layer of oversight that would provide Ofgem with an early warning of any developing circumstances that might act against the interests of consumers.

Dividend policy is primarily an issue that is interlinked to a company's choices over its efficient and prudent financing arrangements, and is a matter of interest for shareholders, whose legitimate expectation of return on their investment is dependent on these dividends. Ofgem recognises that a company's financing choices are the responsibility of the company rather than regulator and note that it is not its role to specify dividend policy, and similarly the legitimate interests of customers in this one specific area of company financing arrangements is unclear.

As with the proposal for additional reporting on Executive Remuneration, Ofgem has failed to demonstrate a benefit from the proposed additional dividend policy disclosure requirements that would justify introducing them, as required under the principles of good regulation and as set out in the Electricity and Gas Acts. These include that regulatory intervention should be proportionate and targeted only at cases in which action is needed. This is especially so, given Ofgem's recognition in the DD that "*It is not Ofgem's role to specify any company* *dividend policy*", suggesting that Ofgem's use for the information is unclear. As for the benefit to other stakeholders (customers and consumers), company financing arrangements are generally highly complex, and making additional information available in one area (in relation to dividend policy) would be prone to misinterpretation, especially if taken out of the context provided by the ringfence conditions in network companies'

These risks are heightened in relation to companies such as NGET and NGG which are subsidiaries of a listed UK company which already provides extensive information on its financial policies at group level. For such companies, these proposals represent Ofgem reaching through the regulatory ring fence and past the ring fence conditions into the wider group which is not directly regulated by Ofgem, and this extension of regulatory oversight is unjustified. Ofgem already has the tools in place that allow it to ensure that consumers are not disadvantaged by actual capital structures diverging from those of the notional company. These include a licence requirement to maintain an investment grade credit rating and the tax clawback, which already incentivises licensees to align with the capital structure of the notional company.

Where a network company, like NGET and NGG, is a subsidiary of a listed UK company that is subject to the UK Corporate Governance Code, the combination of the disclosure obligations already in place at group level, and the requirements of the 'Ultimate Controller Undertaking' that are already mandated through networks' licences, mean that there is even less justification for additional disclosures of dividend policies at licensee level.

Finally, and perhaps most importantly, there are already requirements for annual certificates from each licensee to confirm the sufficiency of its financial (and other) resources, as well as for additional confirmation before declaring a dividend that the making of this distribution will not cause the licensee to be in breach of its financial ringfence obligations (including the need to maintain sufficient financial resources). It is therefore unclear what additional benefit the proposed new requirement for additional reporting of licensee dividend policies will bring to customers/consumers.

Base Revenue definition and ODI cap/collar questions

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

No, we do not agree that the proposed definition of Base Revenue is applicable for all elements of the RIIO-2 framework.

There are four elements comprising the definition of Base Revenue:

- the allowed revenue components contributing to the overall Base Revenue value;
- the point in time at which Base Revenue is fixed;
- the price base in which Base Revenue is stated; and
- the use of average rather than annual Base Revenues.

We do not agree with all of the allowed revenue components which make up Base Revenue as defined by Ofgem paragraph 11.10 of the RIIO-2 Draft Determinations - Finance Annex. We agree with the inclusion of fast pot expenditure, non-controllable opex, RAV depreciation, return, equity issuance costs and core DARTs revenue streams. We also agree with the exclusion of the Business Plan Incentive value from the definition .However, we do not agree with the inclusion of pass through costs, such as shrinkage, operating margins services and net residual balancing costs as these relate to balancing the system rather than the ongoing operation and maintenance of the network.

We do not agree in that fixing the Base Revenue at Final Determinations, the use of a 2018/2019 price base and using a period average value are applicable in all circumstances. The reference to Base Revenue requires assessment for each specific circumstance.

Base Revenue is proposed as a reference point to determine allowed revenue at several points within the RIIO-2 framework:

- Setting the thresholds for ODI caps and collars;
- Determining materiality thresholds for re-opener applications[144];
- The threshold for the "deadband" of the Tax Trigger mechanism[145] and materiality threshold for the residual differences in the proposed tax reconciliation[146].

In each case, as the Base Revenue is referenced in setting a threshold the nature and intent of the resulting adjustment requires consideration to determine the most appropriate definition of revenue used in setting that threshold.

Setting the thresholds for ODI caps and collars

Ofgem proposes that the Customer satisfaction survey ODI has a value range from 0.5% to -0.5% of Base Revenue[147].

Defining the magnitude of an incentive as a proportion of Base Revenue is based on the principle of reflecting the size of the network's investment and operations. Ofgem sets out this principle in the RIIO-T1 initial proposals[148]:

"*1.11. In order to maintain strong output incentives we intend to make sure that where caps and collars apply to these, they do not just reflect the starting position on revenue called the "opening base revenue allowance". Instead, we propose that they adjust in response to*

[144] RIIO-2 Draft Determinations - Core Document, 9 July 2020, Ofgem, para 7.31
[145] RIIO-2 Draft Determinations - Finance Annex, 9 July 2020, Ofgem, page 124, footnote 179
[146] RIIO-2 Draft Determinations – Finance Annex, 9 July 2020, Ofgem, paras 7.46 and 7.47
[147] RIIO-2 Draft Determinations - Gas Transmission Annex, 9 July 2020, Ofgem, page 11
[148] RIIO-T1 : Initial Proposals for National Grid Electricity Transmission and National Grid Gas, 27 July 2012, Ofgem, para 1.11-1.12

ongoing, but uncertain, changes in revenue in order to better reflect the true change in network total expenditure (totex) and other in-period adjustments over the price control period.

1.12. To do this we propose that the maximum caps and collars will be linked to a combination of the opening base revenue allowance plus within-period adjustments captured through annual iteration of the financial model and for NGET the revenue from Transmission Investment in Renewable Generation (TIRG). This will include all additional totex that is triggered during the RIIO-T1 price control period."

Adopting this approach ensures that the rewards and penalties associated with outputs continue to be of sufficient magnitude to incentivise networks to aim for step change improvement.

Ofgem's proposed definition of Base Revenue for RIIO-2 moves away from this concept by fixing the value of Base Revenue at Final Determinations. No justification is provided for this proposed change.

We note that, in Table 42 of the Finance Annex, Ofgem proposes to limit the Base Revenue definition to include NGGT TO only. For incentives which reflect on both the Transmission Owner and System Operator performance, as in the case of the Customer satisfaction survey, we consider that Base Revenue should encompass the business being assessed. Therefore, in the case of ODIs, the Base Revenue term should include both Gas Transmission Owner (GTO) and Gas System Operator (GSO) revenues.

Based on our assessment of Ofgem's totex scenario under which 42% of totex spend is delivered through re-openers not included within baseline allowances, this would limit the incentive range for the Customer Satisfaction incentive to 0.43% to -0.43% on average across the period compared with the 0.5% - to -0.5% range initially intended. This is based on inclusion of GTO and GSO Base Revenues within the definition.

Adjusting the ex-ante value prior to each year based on the Base Revenue value calculated for the year during the Annual Iteration Process (a continuation of the RIIO-1 principle) results in an incentive range calibrated according to the network totex. An annual average value is therefore not applicable as the Base Revenue value for a particular year will only be determined in the preceding year's Annual Iteration Process. We therefore propose that the Base Revenue is determined for each regulatory year.

The definition of Base Revenue also interacts with the proposal to forecast PCFM variable values. The forecast variable values for a particular regulatory year will determine the Base Revenue for that year. However, in order to reflect adjustments to prior year forecasts, for example as a result of finalisation of totex allowances, the adjustments to the component parts relating to prior years must also be included to fully reflect the size of network investment.

We agree that for, ODI range setting purposes, the Base Revenue should be stated in 2018/2019 prices. This is based on the assumption that the inflation index for the relevant year will then be applied to derive the earned income from that incentive.

In summary, the appropriate Base Revenue applied in determining the maximum and minimum monetary values associated with ODIs is the annual Base Revenue combined GTO and GSO values in 2018/2019 price base calculated through the Annual Iteration Process.

Determining materiality thresholds for re-opener applications

Ofgem proposes to set a materiality threshold such that allowances are only adjusted should the re-opener assessment after application of the Totex Incentive Mechanism incentive rate exceeds 1% of annual average Base Revenue[149].

[149] RIIO-2 Draft Determinations - Core Document, 9 July 2020, Ofgem, para 7.31

The application of a materiality threshold follows precedent set in the RIIO-1 framework, Ofgem's reasoning being that this test would *"limit the impact that uncertainty mechanisms will have on end customers' charges"*[150]. However, Ofgem also recognised that mitigating this potential volatility in revenues would have to be balanced against the potential cashflow risk arising from setting a threshold and limiting re-opener windows[151].

The materiality threshold should be considered against the ex-ante Base Revenue fixed at Final Determinations in order that all re-opener applications are measured against a consistent benchmark. In this case, an annual average Base Revenue over RIIO-2 is appropriate to ensure that the threshold is not dependent on the year in which either investment or the re-opener submission is made.

In a continuation of the RIIO-1 precedent, we support separate materiality thresholds for the GTO and GSO businesses. Table 42 of the Finance Annex does not draw out this distinction or even include reference to the GSO base revenue.

A 2018/2019 price base for Base Revenue when used to set the materiality threshold for re-openers is appropriate if the assessment of the re-opener value is also in 2018/2019 prices.

The threshold for the "deadband" of the Tax Trigger mechanism and the tax allowance reconciliation

Ofgem proposes to retain the current Tax Trigger mechanism for Type B events. Changes to legislation and accounting standards which impact on the tax allowance calculation are only reflected when the magnitude of the change exceeds the higher of the equivalent of a 1% change in the corporation tax charge when applied to Base Revenue and 0.33% of the opening Base Revenue allowance[152].

The proposed requirements for an annual reconciliation between the notional tax allowance and actual tax liability as per the CT600 form also references Base Revenue. The proposed threshold below which residual differences in the reconciliation is as defined for the Tax Trigger mechanism.

In principle, we consider that the materiality threshold should be applied to the Base Revenue as calculated through the Annual Iteration Process as this is a more accurate reflection of the tax allowance appropriate for the size of network investment. However, we recognise that this is a complex application which may result in a circularity of calculation. We therefore agree with Ofgem's proposal to link the threshold to the annual average of Base Revenues as at Final Determinations as a pragmatic approach.

In a continuation of the RIIO-2 precedent, we support separate tax trigger and therefore materiality thresholds for the GTO and GSO businesses. As noted previously, Table 42 of the Finance Annex does not draw out this distinction or include reference to the GSO base revenue.

As tax allowances are calculated in nominal terms, prior to conversion to a real price base for the purpose of calculating allowed revenue, the Base Revenue linked threshold should be stated in the same terms.

In summary, a single definition of Base Revenue across the price control is not appropriate and we propose that the thresholds are defined as in Table 17 in line with continuation of the RIIO-1 mechanisms.

[150] RIIO-T1 : Initial Proposals for National Grid Electricity Transmission and National Grid Gas, Cost assessment and uncertainty Supporting Document, 27 July 2012, Ofgem, para 2.11
[151] RIIO-T1 : Final Proposals for National Grid Electricity Transmission and National Grid Gas, Cost assessment and uncertainty Supporting Document, 17 December 2012, Ofgem, para 3.39
[152] RIIO-2 Draft Determinations - Finance Annex, 9 July 2020, Ofgem, page 124, footnote 179

Table 18 Our proposal for Base Revenue definition

	ODI cap and collar	**Re-opener materiality thresholds**	**Tax trigger and reconciliation**
Base revenue	GTO + GSO combined	Separate GTO and GSO threshold calculations	
Revenue components	Fast pot expenditure Non controllable opex RAV depreciation Return Equity issuance cost Core DARTS – directly remunerated services, pension deficit		
Timing of determination	Updated according to the Annual Iteration Process	Final Determinations	
Price base	2018/2019 is appropriate if the inflation index is then applied to the resulting ODI value	2018/2019 is appropriate if the re-opener impact is measured in the same price base	A nominal value is required as tax balances are initially calculated as nominal values
Annual vs average	Annual	Average	Annual
Statement or calculation of threshold	Calculated through Annual Iteration Process Stated within Price Control Financial Model	Stated within Licence condition	Calculated and stated within Price Control Financial Model

Under paragraph 11.51 of the Draft Determations – Finance Annex, Ofgem states that "*Under these proposals, opening revenue allowances will no longer need to be set out in the licence. Instead, the values would be as given in the PCFM published at each AIP, and therefore no 'MOD' term will be required*". This approach is not consistent with either Ofgem's proposed approach to defining Base Revenue or our proposed approach to setting the materiality threshold for re-opener application. Appreciating that a Price Control Financial Model has not yet been shared through the RIIO-2 framework development process, initial indications are that there will be no permanent record of the opening revenue allowances as set at Final Determinations. In order to provide a transparent reference point for the re-opener threshold this value will need to be stated within the relevant licence condition.

We also consider Ofgem's proposal alongside the ongoing development of the network's licence as shared to date with networks. Any reference to Base Revenue in the network's licence, typically introduced as an algebraic term in the calculation of the Allowed Revenue under the Restriction of Allowed Revenue Special Condition, requires consistency in terminology and definition with the Base Revenue term as used elsewhere in the framework.

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

We do not agree with the proposal to fix the value of Base Revenue used for ODI caps and collars at Final Determinations. We propose the use of the annual Base Revenue value in 2018/2019 price base calculated through the Annual Iteration Process. We refer you to our response to FQ37.

The question FQ38 is worded ambiguously and we assume it relates to the definition of base revenue for the use of ODI caps and collars, even though it does not say that specifically.

Finance issues in addition to specific FQ responses

Ofgem has set out areas within the DD Finance Annex where stakeholder views are sought but no specific FQ exists under which to capture these views. We set out these areas below.

Financial Resilience

Chapter 6 of the Finance Annex details Ofgem's proposals for additional resilience requirements for RIIO-2. These would apply should the licensee's issuer credit rating fall to BBB/Baa2 in combination with being placed on negative watch or the licensee be directly downgraded to a lower rating without first being place on negative watch. In these circumstances, Ofgem has proposed that licensees should provide the regulator with:

- published rating reports, where possible; and
- a financial resilience report.

In our financeability assessment, we therefore test our resilience under macro-economic and credible totex scenarios against a threshold above the minimum required to achieve a Baa2 or BBB rating. Below this limit, we can assume, based on Ofgem's financial resilience measures that licensee (albeit on a notional basis) would be required meet the additional requirements and therefore Ofgem's statutory duty to ensure networks are able to finance licensed activities would be at risk.

We also note that Ofgem requires the submission of published rating reports only where this is possible. National Grid is rated by three credit rating agencies, namely Moody's, Standard and Poor's (S&P) and Fitch. Whilst Moody's and Fitch both publish individual NGG reports, S&P does not and only publishes a single report for the Group. Access to rating reports is subject to subscription rights for all three agencies and restrictions apply to how such publications shall be shared externally. As such we cannot guarantee that it is possible to share in this instance, unless a formal request is made, highlighting a regulatory requirement.

Bad debts

Ofgem proposes a bad debt pass through term to recover the amount associated with supplier-related bad debts. On 7 August 2020, Ofgem published an open letter entitled "*Managing network charge bad debt – proposal enabling networks to recover potential bad debts arising from COVID-19 related deferred network charge payments and to introduce an enduring solution to bad debt recovery in general*", the timeframe for response being 4 September 2020.

Overall, we welcome the inclusion of a bad debt recovery term into the RIIO framework but have several concerns and requests for clarification. We refer you to our response to the open letter for further detail.

Appendix 1: Further detail on our response to Ofgem's proposed cross checks

This appendix provides additional detail in our response to Ofgem's proposed cross checks to cost of equity, to supplement our responses to FQ8 and FQ9 (step 2).

Ofgem's proposed 'Modigliani-Miller WACC' cross-check

As explained above in our response to FQ7, the Modigliani-Miller WACC cross-check needs to be carried out correctly, without making errors in the methodology or parameter values used. In particular, the cross check should:

- use a higher RFR;
- use the cost of new debt only when applied to convert the cost of equity between different gearing levels; and
- use better justified estimates of debt beta and TMR (see response to FQ9).

Together these changes virtually eliminate the difference in cost of equity between the cross-check and the traditional de-levering/re-levering approach. In addition, the comparator gearing levels used in the first stage of the cross-check should be based on book value and not market value, unless the difference between market value and book value is going to be taken into account when converting to a cost of equity at the assumed notional gearing.

Once these corrections are made, it is not correct to say, as Ofgem suggests at paragraph 3.102, that this cross check supports a cost of equity below the mid-point of the CAPM range.

Furthermore, this cross-check should only be applied once better justified (and higher) values of TMR and beta values have been set (see the discussion of TMR and asset beta under question FQ9 below). Using these inputs, the cross-check would support a much higher cost of equity than that proposed by Ofgem in the DD, consistent with the values that would be calculated using the better justified and higher RFR, TMR and beta values under the traditional de-levering / re-levering approach.

MAR as a cross check

At paragraph 3.103, Ofgem suggests that *"The MARs cross-check is persuasive. As noted at paragraphs 3.67 to 3.74, market reactions to Ofwat's allowed return on equity of 4.19% (appointee level) is, we expect, priced into MAR values for UU, SVT and PNN. Compared to other cross-checks there are fewer comparison issues, given the consistent notional gearing of 60% and the view that systematic risk is similar for energy and water networks"*. We do not agree as Ofgem are wrong to assume energy and water risks are similar and interpretation of MAR evidence is complex requiring significant levels of judgment. Oxera have also reviewed the use of Market-to-Asset ratios (MARs) in their latest cost of equity update report[153] and conclude that *"In light of the uncertainty in apportioning components of equity market valuations to individual elements of the regulated settlement, there is no reason to depart from the position as stated in previous CMA assessments and the UKRN cost of capital study - evidence from traded market premia does not provide a reliable guide in practice to the cost of equity used by investors in regulated utilities."*

MAR as a cross check: Ofgem's assumption that energy and water risk is similar is contradicted by direct market evidence

We do not agree that the systematic risk is similar for energy and water networks, and that the allowed cost of capital for an energy network does not need to be higher than for a water network company. As explained in our response to question FQ5 above, there are good

[153] "The Cost of Equity for RIIO-2 Q3 2020 Update", Oxera, prepared for the Energy Networks Association, September 2020, Section A2.5

reasons to believe energy networks face higher risk. Whilst such views and a consideration of qualitative factors may be seen as subjective, it is safer to consider the evidence from beta values for listed energy and water companies, and this appears to confirm that energy networks face higher risk:

- Even using Ofgem's choices of sample lengths and averaging periods (see DD Table 14), a comparison of the asset beta for National Grid and listed UK water companies clearly shows that National Grid, even at Group level, faces higher risks than the water companies.
- Once disaggregation is taken into account, allowing the lower risk of National Grid's US businesses relative to its UK networks to be taken into account, it is clear that National Grid's UK transmission networks have an appreciably higher asset beta than the water companies. Thus, Ofgem's MAR analysis, based primarily on the MAR values for SVT, UU and PNN, is inherently not persuasive in relation to the required cost of equity for energy networks[154].

MAR as a cross-check: calculation and interpretation of MAR evidence is complex, requiring significant levels of judgement.

There is inherent uncertainty associated with MAR analysis and, given the range of assumptions that need to be made to derive any implied cost of equity from this method, the approach is highly unreliable and imprecise. The CMA too has recently suggested that little weight should be placed on forward-looking approaches such as interpretation of apparent MAR values as the CMA has *"preferred to focus [our] assessment on the historic data, which we consider to be more robust"*[155].

Even on its own terms, Ofgem's discussion of the water company MAR values, or CEPA's analysis on which it is based, seems suspect and appears to reach unreliable conclusions in relation to the required cost of equity. Oxera have prepared a report for the ENA which considers *"What explains the valuations of listed water companies?"* and this has been submitted to the CMA in relation to the appeals of PR19 by 4 water companies. As summarised in the ENA's submission to the CMA at the end of May 2020[156], and as illustrated diagrammatically in Oxera's latest report[157]:

"*ENA disagrees with Ofwat's reliance on its MAR analysis for UU and ST to support its allowed cost of equity for the water industry, as this does not constitute reliable evidence. Moreover, even if the inherent uncertainties in undertaking this kind of analysis are ignored,* ***an improved analysis demonstrates that traded equity premia over the notional equity portion of RCVs for UU and ST can be explained without any recourse to an assumption that the actual cost of equity is lower than the regulatory allowed base equity return; and, to the extent that conclusions can be drawn, the analysis is consistent with the conclusion that Ofwat has underestimated the cost of equity***."

We agree with these views. In addition, there will inevitably be significant problems in attempting to include National Grid and SSE in MAR analysis given the extent of their business

[154] CEPA's report does include some estimation also of apparent MAR values for SSE and National Grid, but SVT and UU are the only even approximately 'pure play' companies in CEPA's analysis, as the others are also engaged in other business (either non regulated network or outside the UK). CEPA itself criticises a decomposition approach in other parts of its analysis, indicating that it would then be inconsistent to include NG, SSE, and PNN in their MAR analysis.
[155] "NATS (En Route) Plc /CAA Regulatory Appeal Provisional findings report", March 2020, paragraph 12.231
[156] Ofwat Price Determinations: Submission by Energy Networks Association to the CMA, identified on CMA website as submission of 1 June 2020, https://assets.publishing.service.gov.uk/media/5ed0f2b3d3bf7f45fb321450/Energy_Networks_Association_submission.pdf

[157] "The cost of equity for RIIO-2 Q3 2020 Update Report", Oxera, prepared for the Energy Networks Association, September 2020, Section A2.5 and in particular Figures A2.3 to A2.6.

activities outside of UK regulated networks. This would further compound the already high level of uncertainty that is intrinsic in attempting to derive implications for cost of equity through MAR analysis.

We also note that even the values of the MAR premia for National Grid presented by Ofgem in Figure 19 (reproduced from CEPA's analysis) in the DD are inconsistent with the MAR premia for National Grid's UK networks that have been contained in recent analyst reports – and this is before the question of how MAR values might be interpreted even arises. Five recent reports since 9 July 2020 have average premia of around 0 for NG, with two of the reports stating a negative MAR premium (that is, MAR <1) and two indicating a MAR of around 1 (see our response to question FQ10 for further details of these values). This gives rise to two observations:

- This inconsistency casts further doubts over CEPA's MAR analysis, not only for National Grid but over the approach in the study as applied to all the companies it included.
- The range of MAR values in these different reports, published within a short space of each other, is a further indication of the subjectivity and unreliability of using MAR evidence as an indication of cost of equity expectations in the market, even as a cross-check.

It is widely recognised that MARs are difficult to interpret (as explained in the UKRN report at Appendix J and by NERA[158]) due to sizeable and uncertain distortions. 'Transaction' MARs are particularly difficult to interpret, but the MAR values implied by the market values of listed companies are also hard to interpret. This is because it is not possible to disaggregate any overall expected out-performance (or under-performance) between cost performance, incentives performance, cost of debt performance, and differences between the allowed and actual cost of equity. Any premium or discount to RAV could reflect many different possible combinations of anticipated out- or under-performance in each of these separate areas. These may not only be in relation to the current price control and next price control but also all subsequent price controls, as well as being affected by wider market "noise".

In relation to transaction MARs, the UKRN report explained that *"What is evident from this analysis is transaction premia alone do not provide sufficient evidence to make inferences about the cost of equity. Different drivers of outperformance are at play and multiple combinations of various drivers can explain observed premia. In addition, the role of expected outperformance means that the premia may result from unobserved investor assumptions that may be considered unrealistic or optimistic but are nevertheless the reality behind the premia. For these reasons, we consider that evidence from transaction premia is less reliable and much harder to interpret than other sources of evidence on the cost of equity."* Similar concerns apply also to listed company MARs.

Fundamentally, therefore, an assessment of MAR values is unable to give a reliable indication of the cost of equity for a regulated energy network. The reasons are explained more fully in the ENA's recent submission to the CMA at paragraphs 4.3 to 4.18[159] and in Oxera's latest cost of equity update report[160], and include the following:

- MAR values are forward looking, so estimates of the factors that contribute to the estimated MAR values for a company are necessarily based on assumptions of investor expectations across a range of factors which cannot be observed. The market's view of future outperformance involves significant uncertainty, and a wide range of views exist in the market.

[158] "Implications of Observed Market-to-Asset Ratios for Cost of Equity at RIIO-T2", NERA Economic Consulting, 1 Dec 2017, Page 10

[159] Ofwat Price Determinations: Submission by Energy Networks Association to the CMA, dated 1 June 2020, https://assets.publishing.service.gov.uk/media/5ed0f2b3d3bf7f45fb321450/Energy_Networks_Association_submission.pdf

[160] "The cost of equity for RIIO-2 Q3 2020 Update Report", Oxera, prepared for the Energy Networks Association, September 2020, Section A2.5

- These expectations also relate to performance of companies not just in the next price control period, but in all subsequent price controls, and so will be affected by investor expectations of the basis of future price controls, which may include, for example, an expectation of higher allowed return in future controls.
- There may be drivers of RCV premia other than outperformance and allowed returns, but these appear to be ignored in Ofgem's/CEPA's analysis
- Even the estimated MAR values themselves will be uncertain, given that they depend on the values assumed for other (e.g. non-regulated) businesses and activities with the listed company groups.
- There are therefore significant uncertainties associated with interpreting MARs, which are recognised in the regulatory precedent of attaching little weight to estimated MARs.
- Whilst water companies cannot be assumed to be exposed to the same risks as energy networks, United Utilities and Severn Trent are not even representative of the performance of the wider sector. Both UU and ST are both widely expected to perform strongly relative to the peer group (in PR19 and probably beyond) for a variety of reasons, including in relation to service targets and incentives, totex allowances, cost of debt. They, like Pennon, were also fast-tracked in PR19, leading to additional revenues in the base return as well as much smaller cuts to their business plans in PR19 than for most of the water companies.
- A critical assumption is the period over which the share price is analysed. Figure 10 in the DD shows how MAR values vary significantly across the years of a price control (whether from 2005 to 2010 for PR04; 2010 to 2015 for PR09; or 2015 to 2020 for PR14). Figure 9 in the DD presents MAR values on three specific dates between the end of December 2019 and May 2020, and the extent of fluctuations in apparent MAR values over time that is illustrated in Figure 10 shows that it would be unreliable to attach weight to such evidence when taken from a period that covers just 5 months.

In addition, Pennon has recently completed the sale of its Viridor waste business. The market's view of this significant transaction, for a sum that is comparable to Pennon's RAV, will have impacted on Pennon's share price in recent months, making the analysis of Pennon's MAR during this period unreliable. Severn Trent also has a non-trivial non-regulated business which would need properly to be taken into account when analysing its MAR.

It is a fundamental difficulty with interpretation of MAR data to estimate cost of equity that the results depend on investor expectations for the future, both of actual costs and performance, and expectations of the level of future regulatory allowances, not only for the next price control but also for all future price controls. In addition, as shown by Oxera there are also a range of further factors that should be taken into account and contribute to market participants' investment decisions and thus company share prices, but these do not seem to be considered by CEPA or Ofgem. These are, unavoidably, not observable, rendering the analysis imprecise and unreliable.

OFTO returns have a much lower risk profile than energy networks and therefore do not represent a relevant cross-check

Ofgem then seeks to compare the CAPM derived cost of equity to the equity returns required by winning bidders for offshore transmission projects (OFTOs). Ofgem themselves have recognised the differing risk profile for these projects from that of network operators[161]. For example, OFTOs face significantly lower risks in many areas such as:

[161] See for example "RIIO-2 Sector Specific Methodology Annex: Finance", Ofgem, 18 December 2018, (paragraph 3.137)

- The absence of regulatory reset risk as a result of their revenue streams being set for 20 years corresponding to the initial full operating period of the assets, until initial investments have been fully recouped;
- the assets are already constructed, but new;
- they do not face political risk; and
- operating and maintenance costs are low, so the corresponding risks are low.

These differences in risk are so great as to make the investment propositions completely different, so the comparison of equity returns is meaningless.

A further concern is that OFTO returns are likely to materially understate the overall equity returns that are actually expected by investors in these projects, as they omit certain significant sources of value on a probability-weighted or expected value basis. These include investors' expectations that they will be able to benefit from Terminal Value at the end of the initial 20-year contracted revenue stream and differences in the likely tax treatment of the project assets from that which has been assumed in the tender revenue stream.

Ofgem previously drew attention at paragraph 3.136 (in the SSMC) to the falling cost of equity for OFTO projects over time and suggested that this is a cross-check to the proposed reduction in cost of equity from RIIO-1 to RIIO-2. However, this does not follow – the 3% reduction in OFTO returns will be attributable to other factors which do not apply to RIIO, such as a growing familiarity with the OFTO regime (as has previously been recognised, for example by CEPA in their 2016 report for Ofgem[162]). In addition, the higher gearing for OFTO projects implies a relatively small change in the project WACC of c.0.3% over time, which would translate to less than a 1% change in cost of equity at the gearing levels applied to energy networks.

Fundamentally, this suggested cross-check involves reference to operational OFTO projects, and so prospective investors are bidding for activities which are very different from and not comparable to energy network businesses. OFTO projects also operate under very different regulatory regimes. Any information on required returns in OFTO bids is therefore not informative when considering the returns required by networks under RIIO-2. This appears to be implicitly recognised by Ofgem itself. In the summary of cross-checks at Table 24 in the DD, Ofgem simply presents unadjusted OFTO equity IRR data - which according to Ofgem is 4.9%[163] and so actually higher than Ofgem's proposed allowed equity return under RIIO-2 without attempting to make any necessary adjustments to make the information in any way comparable to required energy network returns, such as for differences in risk, as well as differences in gearing. This therefore cannot be seen to support the much lower proposed RIIO-2 return.

The reasons why OFTOs face much lower risk than onshore network activities are numerous, but include onshore networks businesses being diverse and complex, facing construction risk, and being subject to political as well as regulatory reset risk every five years. In contrast, the OFTOs' business activities that bidders are competing for have a much narrower scope of activities and range of risks associated with operating already constructed, new, radial offshore links which have no political or regulatory reset risks for the next 20 or 25 years, i.e. until initial investments have been fully recouped. Winners of the OFTO competitions have often made strong assumptions in relation to tax and terminal asset value which are not reflected in the quoted cost of capital figures. There are also examples where OFTO projects have proved to carry more risk than originally anticipated by the party which bid for it[164].

[162] "Evaluation of OFTO Tender Round 2 and 3 Benefits", Cambridge Economic Policy Associates Ltd, March 2016

[163] This is based on OFTO bids which do not appear to be in the public domain, and so is information which networks are not able properly to review. This creates a further problem of transparency and information asymmetry if Ofgem were to seek to use this information to inform the required returns for RIIO-T2.

[164] See for example https://www.moodys.com/research/Moodys-changes-outlook-on-Gwynt-y-Mor-OFTO-PLCs-rating--PR_364937

In RIIO-1, and now RIIO-2, in the qualitative assessments of networks' risk profiles, Ofgem has recognised the importance of the capex programmes that network companies will undertake as part of the full range of licensed network activities, considering both the scope and complexity of the capex programme, and also the size of the programme. It would therefore be inconsistent for Ofgem now to attach weight to a cross-check to returns on OFTO projects which have such a different scope of activities and involve effectively no capital investment at all.

We therefore consider that the information on OFTO returns that is contained in the DD is not relevant and does not require any further comment in this consultation response. We highlight that National Grid has previously provided more extensive comment to explain why observed OFTO rates - which relate only to the operational period for an offshore transmission link – are not informative when considering required returns on onshore assets, even in relation to a single project, where the similarities might at first sight have seemed greater than in relation to the planning, construction, maintenance and operation of a whole network. See, for example, National Grid's response to Ofgem's 15 October 2019 consultation "*Consultation on the Hinkley-Seabank updated delivery model minded-to position*"[165]. In their latest cost of equity update report, Oxera agree that "*that inferences made from OFTO bids should not be used to benchmark the CoE for onshore energy networks*."[166]

Investment manager forecasts of TMR are not a relevant cross-check for cost of equity, and we are not aware of any regulatory precedent for their use

Ofgem suggests using investment manager forecasts of TMR as a cross-check of the cost of equity of energy networks, by using the TMR forecasts in the CAPM, together with assumptions for the risk-free rate and equity beta. To the extent that this data can be used as a cross-check, it would make more sense for it to be considered and used as a cross-check of the TMR value that is to be used in Step 1 of Ofgem's methodology for estimating cost of equity, rather than attempting to use it as a cross-check of the cost of equity.

However it was used though, we have reservations regarding the use of this data, as previously explained in our response to the SSMC of December 2018[167]. In summary:

- We are not aware that such evidence has been used or given much weight in any previous price controls, so giving weight to this evidence for RIIO-2, when it appears at first sight to be inconsistent with more established and robust approaches, would seem a significant break with precedent.
- Oxera have previously reviewed this evidence for the ENA[168]. After considering both the FCA's 'regulation of market return' assumptions (which is one of the data values referred to by Ofgem) and the limitations of the evidence from investment managers, Oxera's conclusions (Section 4 of their report), with which we agree, included:
    - "*With regard to evidence from the FCA, the 6–7% nominal range for the TMR is likely to be below a central estimate of the expected TMR, for at least two reasons. First, the FCA-prescribed range was designed to ensure that consumers did not suffer from overly optimistic performance forecasts. ... Second, the expectation that the welfare-enhancing TMR assumption for the purpose of investment advice would sit towards the lower end of the evidence is borne out by the data*."

[165] National Grid consultation response, 26 November 2019, https://www.ofgem.gov.uk/system/files/docs/2020/05/nget_response_delivery_model.pdf
[166] "The cost of equity for RIIO-2 Q3 2020 update", Oxera prepared for the Energy Networks Association, September 2020, Section A2.1
[167] National Grid's response to Ofgem's RIIO-2 sector-specific methodology consultation – Finance, available from Ofgem's website: https://www.ofgem.gov.uk/publications-and-updates/riio-2-sector-specific-methodology-consultation
[168] "Review of RIIO-2 finance issues: Rates of return used by investment managers", Oxera, prepared for Energy Networks Association, March 2019

- "*With regard to the evidence from investment management firms, it is recommended that no weight is placed on these observations, due to the limitations summarised below.*

  First, in contrast to Ofgem's original intention, it is unclear whether the evidence presented can be used 'to advise clients and allocate funds'. In fact, the majority of the underlying publications explicitly state that the figures presented therein cannot be used as estimates of future returns.

  Second, academic research and precedents from practitioners show that survey evidence should be attributed little weight. Given that Ofgem recognises the benefit of predictability and stability in regulatory policy, it appears appropriate to attribute more weight to historical evidence than to the individual forward-looking projections.

  Finally, if any weight is to be placed on this evidence, the projected growth rates reported therein must be adjusted for the downward bias embedded within such estimates. Academic literature suggests that the adjustment amounts to c. 2%."

- Furthermore, the FCA's aim in setting prescribed rates is to prevent consumers from being misled by inappropriately high rates, and the TMR estimates produced by investment managers have the primary purpose of providing prudent estimates of future returns to their clients, to ensure clients are managing their finances prudently. For this reason, their rates are more likely to lean towards the low end of the range, in contrast to the regulation of regulated utilities, where it has been recognised that setting the allowed rate of return too low may exceed the detriment from setting too high a regulated return relative to the true cost of capital.

- We also noted that the CMA, in its Final Determination of the NIE (2014) appeal, considered the suitability of consensus or survey-based approaches from investors, market participants and academics as a possible source for forward-looking estimates of equity market returns. The CMA decided not to give weight to these sources, for reasons explained at paragraph 13.156[169] but fundamentally because the CMA "*preferred to consider the underlying data on which survey respondents presumably base their views*". The same rationale would apply to the alternative views of future market returns from investment managers or advisers, who would use the same approaches to estimate these returns (such as an assessment of historic returns and DDM) as are directly available to regulators and CMA.

In the DD, Ofgem presents estimated values from a number of investment managers that were original included in the May 2019 SSMD, as well as certain updated values taken from these particular investment managers[170], although none of these values are more recent than December 2019. At Paragraph 3.92 Ofgem suggests that this data shows a fall in TMR since May 2019, but does recognise there are reservations that should be taken into account when looking at this data:

- updated forecasts may not be on the same basis as May 2019; and
- given the impact of COVID-19 which has materialised since December 2019, these forecasts may now be out of date.

[169] "Northern Ireland Electricity Limited price determination", Competition Commission, March 2014, paragraph 13.156

[170] We note that in the SSMD decision Ofgem recognised (at Paragraph 3.90) that "*We contacted the investment managers and received confirmation that their published values are in geometric terms. We therefore agree with Oxera that geometric averages may need upward adjustment. Oxera suggested an uplift of 2% but it is much less clear to us that this quantum is appropriate*." Ofgem then presented the results with an uplift of 1% applied. It is not clear whether the values of investment manager forecasts presented in the DD again include this uplift.

Oxera have raised a number of additional concerns with this data[171]. Only two of the investment manager forecasts in Ofgem's table showed a material fall between the May 2019 SSMD and the updated data in DD, and neither of these reductions appear robust:

- Considering first the updated Schroder's estimate – almost all the decline in Ofgem's estimated TMR is due to a change in the investment horizon for Schroders. In addition, Schroders calculates its UK estimate using US data. This new value for Schroders is much lower than almost all the other forecasts, and given that it is based on a projection from US data, there is strong case for this data point being disregarded.
- Considering next the Blackrock estimate, which is the second of the values that are shown by Ofgem as having fallen materially, as noted by Ofgem this is not a like-for-like comparison, as the value changes from an EU TMR in December 2018 to a UK TMR in December 2019.

Without including the results from these two investment managers, where the basis of their estimates has changed, Ofgem's average of the other investment manager forecasts (which also excludes Willis Towers Watson and Vanguard) would actually have increased since the May 2019 SSMD by c.0.35%, from 7.35% to 7.71%

As Ofgem has noted, the investment manager forecasts of TMR which Ofgem has included in the DD all precede the coronavirus pandemic; they are all from December 2019 or earlier. The Bank of England has commented that the elevated levels of stock market volatility and the sharp falls in share prices in March 2020 as a result of the developing Covid-19 pandemic imply that investors require a higher return on equity for the risks they face:

- "*Equity prices fell around the world in March as the worldwide spread of Covid-19 became apparent (Chart 2.11). ... While the outlook for most firms' profits had worsened, the falls in equity prices were much larger than would be implied by announced earnings downgrades. That suggests investors were demanding a higher risk premium to hold equities, and that they were potentially anticipating further earnings downgrades*"[172].
- There has been a modest recovery in equity price since May, particularly in overseas markets, suggesting the increased risk premia may have partly fallen back. However, volatility remains high and the UK stock market is still significantly below its value prior to the pandemic (as of August 2020 the FTSE-all share index is still 20% below its average value in January 2020), implying that views of TMR will now be somewhat higher that at the time of the investment manager forecasts which Ofgem have referenced.

Notwithstanding that we would not put evidential weight on transient forecasts by investment managers, at least three of the investment managers that Ofgem have referenced appear to have published more recent forecasts:

- JP Morgan produced an updated set of Long-term Capital Market Assumptions as at March 2020[173] which include values of return on 'large UK caps' and gave an arithmetic return of 11.35% and a compound (i.e. geometric) return of 10.10%. The equivalent compound return at September 2019 was given in the same document as 7.6% (though Ofgem report a figure of 6.9% for JP Morgan as at September 2019), suggesting expected TMR had increased by at least 2.5% to 3% compared to earlier periods and the values in Ofgem's table.
- Blackrock also produce an update in May 2020 which showed a geometric mean equity return in the UK over 5 to 15 years had risen from 3.7% to 5.5% previously to a new forecast level of 8.2% or 8.3%, suggesting expected equity returns over a 10 year horizon had increased by at least c.3% compared to earlier forecasts.

[171] "The Cost of Equity for RIIO-2 Q3 2020 Update report", Oxera prepared for the Energy networks Association, September 2020, Section A2.4
[172] Bank of England Monetary Policy Report May 2020, page 26.
[173] https://am.jpmorgan.com/blob-gim/1383647200492/83456/JPM52180%20LTCMA%202020%20MATRIX%20-%20USD.pdf

- Vanguard has produced updated estimates of returns on different asset classes as of August 2020 but this only appears to give 10 year annualised compound equity returns for US equites and for 'Global excluding US' equities: the mid-point of the range for 'Global excl US' is 8%. Since JP Morgan's forecast returns for the UK are either higher or comparable to those for most other equity markets, this 8% figure would be expected to understate Vanguard's estimate of 10-year returns for the UK, but even at 8% it represents a 3% increase on the value given for Vanguard in Ofgem's Table 23 of the DD
- Importantly, it should be noted that the values referred to above for JP Morgan, Blackrock, Vanguard do not include the required adjustment to increase them from a geometric average expected market return to a TMR rate for use in the CAPM. In the SSMD, Ofgem agreed that such an increase was needed and applied an uplift of 1%.
- If these c.3% increases in required equity returns were repeated across the other investment managers in their updated forecasts this year, Ofgem's mean value of investment manager forecasts as given in Table 24 would increase from 7.1% nominal/5.0% real relative to CPI to c.10.1% nominal or c.7.9% real relative to CPI. This would compare to Ofgem's range for TMR (as used in Step 1) from 6.25% to 6.75% and would support a corresponding increase in the CAPM calculated cost of equity. Alternatively, if used as a cross-check with a RFR of -1.48% and an equity beta of 0.9 (as in the cross-check summary table given in the DD table 24), it would give a cost of equity of 7.0% relative to CPI, compared to Ofgem's cost of equity estimate in the DD after Step 2 of 4.2% (see Table 25).

Investment managers have also noted that as a result of the COVID-19 pandemic, the range of future economic outcomes remains unusually wide. As a result, the range of uncertainty around expected future levels of equity market return will be much wider than usual. In these circumstances, it would seem inconsistent with Ofgem's financing duty to adopt a TMR value that is materially below expected future values under some plausible scenarios when setting the allowed equity return for the RIIO-2 price control.

Infrastructure funds have a lower risk profile and are therefore not a relevant cross check to cost of equity

At paragraphs 3.93 to 3.96 of the Draft Determinations Ofgem describes a proposed cross check to the discount rates and implied rates of return for a number of Infrastructure Funds. The Sector Specific Methodology consultation from December 2018 previously considered the discount rates for a smaller group of funds, and in response to this proposal a number of network company responses and supporting consultants' reports had shown that these rates are not comparable to the required return on equity for an energy network company.

In our own response, we observed that "*Ofgem present a table of discount rates for several listed infrastructure funds in Table 15 on page 47 of the Finance annex to the consultation, but it is clear that most of these are such poor comparators to energy networks that the information is not relevant to an assessment of the return required by equity investors in energy networks. Ofgem recognise (paragraph 3.139) that the funds "invest in private finance initiatives, infrastructure and also in private utility assets, such as OFTOs", suggesting they are not comparable to energy networks. ... The investment funds may be more comparable to OFTOs given their guaranteed full-life revenue streams which are not subject to any regulatory reset risk*".

Oxera, for the ENA[174], had written a report to review the range of infrastructure funds' discount rates used by Ofgem in the RIIO-2 SSMD as a cross-check. Oxera concluded that "*A comprehensive review of the infrastructure funds' risk and return characteristics suggests that the funds' discount rates are not an appropriate cross-check to determine the upper bound or the lower bound of the CAPM cost of equity range. This is because:*

[174] "Infrastructure fund discount rates", Oxera, Prepared for Energy Networks Association, 20 March 2019

- *the funds' asset composition makes them less risky than energy networks. Moreover, where funds' portfolio investments face greater revenue or volume risks than energy networks, these are generally hedged by long-term or availability-based contracts and/or government subsidies e.g. renewable obligation certificates (ROCs);*
- *the funds' net asset value premia have decreased since 2017. As of 2018, the average net asset value premium was 1.8%, which does not suggest a divergence between the discount rate used by the funds and the rate used by the investors in the funds*."

KPMG, in a report written for Cadent[175], reached the following conclusions: "*Ofgem also presents a number of fund discount rates which are used as a proxy for the expected level of equity return that a particular fund may target. However, the risk profile of the asset portfolios held by the funds selected by Ofgem differ materially from the risk profile of the UK energy networks. For example, the majority of the assets in the selected funds are in PPP/PFI style investments bear no/limited construction risk or comparable operational cost risk as RIIO regulated networks. These types of assets are generally accepted to be in a lower category of the risk/return space when compared with energy networks. It is also unclear how the funds were selected in the first instance. If more appropriate comparators were used, the implied level of expected IRRs would increase significantly. Notably, a simple addition of more appropriate funds to the data widens the current range of 7.2%-10.2% to 7%-12%, although due consideration must be given to how a single figure estimate is derived from the data*."

These earlier responses also provided more extensive commentary to describe the activities of the infrastructure funds and extracts from publications by those infrastructure funds that were considered by Ofgem to show that these are poor comparisons to energy networks. In the interests of brevity these are not reproduced here, but Ofgem are referred again to the earlier submissions and consultation responses that were submitted to the SSMC.

To address these concerns, Ofgem collected additional information on the mix of activities within the funds (presented in Appendix 3 of the SSMD) and reproduced a chart that had previously been presented to investors by one of the funds to show the relative risk of different kinds of projects.

- The information in the Ofgem's SSMD Appendix 3 confirmed the comments Ofgem had received to the consultation that the funds were not comparable to networks. The funds mainly focused on operational assets with no construction risk, and in addition in most cases were focussed on PPP/PFI projects which are lower risk than regulated networks, given for example that they have secure revenue streams for the life of the assets rather than regulatory reset risk every 5 years (see Ofgem's Figure 15 in SSMD).
- Appendix 3 also reported that comparable measures of gearing for the different funds might not be available, but Ofgem had "*found gearing ratios from 0% (3i Infrastructure) to c.15% (JLIF, GCP)*". This also casts doubt on the comparability of the funds and of their required equity returns to energy networks, for which a notional gearing of 55% to 60% is proposed and actual gearing has been in the range from 40% to 60% (see DD Table 13).
- The chart presented in Figure 15 at paragraph 3.214 of Ofgem's May 2019 SSMD shows that the fund (BBGI) considered PPP projects to be less risky and to require lower returns than regulated utilities. As Ofgem note, the data behind this chart was attributed by BBGI to PwC. When the original PwC source is reviewed, it is found that it actually refers to a required return for regulated utilities of 7% to 9% (rather than the 7% to 8% plotted by BBGI)[176]. Converting to a CPIH-real basis gives a real range from 4.9% to 6.9% which is obviously significantly above Ofgem's proposed cost of equity in RIIO-2 in the DD (3.95%

[175] "Cost of Equity and the RIIO-2 Consultation", KPMG, Prepared for Cadent, 13 March 2019
[176] https://www.bb-gi.com/media/1141/31-aug-2018-2018-interim-results-presentation.pdf - slide 27 shows a range from 7% to 8% for regulated networks & attributes it to PwC: the original PwC source from 2017 appears to be the following: https://pwc.blogs.com/deals/2017/10/many-happy-returns.html, which gives a range from 7% to 9%, even before any recent increases required returns are taken into account

at 60% gearing or 3.70% at 55% gearing), casting further doubt over the reasonableness of the proposed return.

Ofgem's overall criticism of the company responses in relation to infrastructure funds was set out at paragraph 3.126, "*In general, company arguments on infrastructure funds were not well-supported with additional evidence. KPMG's review was the most detailed (see our view of Consultancy Report 12 at Appendix 2 below). We are not persuaded by recommendations to include 3i within our primary cross-check sample*". However, it is difficult to see what additional evidence could have been provided. The networks pointed out that the infrastructure funds were not engaged in the same activities as regulated networks, and have lower risk, making a direct comparison between the funds and regulated networks unreliable, and the chart and data put forward by Ofgem supported this, suggesting further evidence is not actually needed.

For the DD, Ofgem has amended its approach with two main changes:

- As explained at paragraph 3.94, Ofgem "*now include a wider sample of infrastructure funds, increasing the original total from six to fourteen*"
- Then Ofgem "*make three further analytical improvements. First, we obtain time-series data for discount rates and premium to NAV. Second, we infer an Internal Rate of Return (IRR) by combining this information. Third, we derive weighted and simple averages to help isolate fund-specific or idiosyncratic issues*."

Unfortunately, these changes fail to address the fundamental problems with using infrastructure fund discount rates as a cross-check which were previously pointed out.

Most importantly, the lack of comparability of the business activities of the original 6 funds to regulated networks remains (and according to Ofgem's SSMD Appendix 3 they also have substantially lower gearing, at least in some cases). It is not addressed by the inclusion of an additional 8 funds which are even less comparable to energy networks, so that the averages that are calculated by Ofgem across these 14 funds will have little relevance to the returns required by investors in energy networks. The additional funds are almost all entirely investors in renewable energy projects (e.g. solar and onshore wind), which have fundamentally different risks from energy networks.

This lack of comparability is compounded by Ofgem's selective approach to the data: the company which had the highest reported discount rate, 3i, within the original group of 6 companies is now excluded from Ofgem's averaging and from Figure 13, and Ofgem has chosen not to include a larger group of other infrastructure companies which have higher discount rates (target IRR from 10% to 15%) and were drawn to their attention by KPMG in their report for Cadent.

At paragraph 3.96 Ofgem summarises its views on this cross-check as follows "*We have not attempted to present IRRs on a risk-adjusted basis, and hence acknowledge asset or financial risk could impair comparability among funds and/or direct applicability for RIIO-2. Nonetheless, we note this analysis indicates: several funds imply equity returns less than 6% nominal with an average of 6.3%; and, a fall in returns of approximately 1.5% since 2014. Further, we note that the combined value (share price * shares) of the funds is approximately £20bn as at 31 March 2020, signalling strong investor appetite for infrastructure investments*."

Considering these comments:

- *"We have not attempted to present IRRs on a risk-adjusted basis, and hence acknowledge asset or financial risk could impair comparability among funds and/or direct applicability for RIIO-2."*

  Here Ofgem appears to be recognising the limited comparability of the returns required by these funds to required energy network returns.

- *"Nonetheless, we note this analysis indicates: several funds imply equity returns less than 6% nominal with an average of 6.3%*"

An average of 6.3% would equate to a real return of 4.2% real relative to CPIH, but as this is for projects with lower risk than regulated networks (and according to Ofgem's SSMD data very much lower gearing, as confirmed more recently by Oxera[177]) it would imply that the proposed RIIO-T2 return is too low.

- *"a fall in returns of approximately 1.5% since 2014"*

  The formula applied by Ofgem to produce DD Figure 13 relies on an assumption that any premium above NAV means that a fund is overestimating its own cost of capital, but there are multiple explanations for market valuations that do not rely on the overestimation of cost of capital. It will also result in any actual reductions in discount rate over time being overstated, and could only calculate the implied fund IRR if: all projects were entered into at times when the discount rate was the same; all projects achieve this discount rate (but no more); and there are no other sources of value that now contribute to the fund's share prices other than the return on the portfolio of existing investments.

- *"Further, we note that the combined value (share price * shares) of the funds is approximately £20bn as at 31 March 2020, signalling strong investor appetite for infrastructure investments"*

  It is not clear how this is relevant when considering the required return on a different type of investment, i.e. regulated networks that are, for example, subject to regulatory reset every 5 years.

In their latest cost of equity update report, Oxera have further considered the information on these infrastructure funds, and estimated the implied TMR for each fund based on its cost of equity (assuming this is equal to its discount rate) and beta, as a cross-check for the reasonableness of this data. These implied TMRs ranged from 12% to 28% (real relative to CPIH) with an average of c.17%. Oxera conclude that "*This is so high as to be unreasonable. Although infrastructure funds may relay useful data in some cases, they are clearly inappropriate for a CoE cross-check for regulated UK energy firms. The implied TMR and lack of consistency between their own betas/CoE suggest that this data is unreliable for the type of cross-check attempted by Ofgem and that infrastructure funds' discount rates are not an appropriate benchmark for the cost of equity in RIIO-2*"[178].

In conclusion, whilst we do not consider the infrastructure fund discount rates provide a meaningful cross-check of the cost of equity for a regulated network operator for the reasons explained above, if Ofgem were to give weight to this information it would support a higher cost of equity than Ofgem have proposed.

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[177] "The cost of equity for RIIO-2 Q3 2020 update", Oxera, prepared for the Energy Networks Association, September 2020, Section A2.2

[178] Ibid.,

Appendix 2: Further detail on our response to Ofgem's proposed TMR methodology

This Appendix provides a more detailed summary of our arguments on TMR, to supplement our response to FQ9.

TMR Issue 1: The CPI back-cast used to deflate the actual return is considered unreliable by its authors and the ONS

This issue was considered by the CMA in the recent appeal by NATS[179], and the estimate of TMR is also a point of consideration in the ongoing PR19 appeals by 4 water companies. Ofgem appears to take comfort from the Provisional Findings of the CMA in the NATS appeal[180] as support for the RIIO-2 DD value of TMR. In particular, at paragraph 3.22 Ofgem state "*Noting the CMA proceedings are ongoing, and that the 17 of November 2020 is the statutory deadline for a determination to be sent to the CAA, we will consider the CMA's final view alongside stakeholder responses to these draft determinations, prior to making final determinations for RIIO-2*" The Final Report of the CMA in the NATS appeal has now been published, but in light of the significant impact of the COVID-19 outbreak on the airline industry, this final report did not take account of evidence received by the CMA in response to the NATS Provisional Determinations to reach a final position on either TMR or RFR, as is clear from the following extracts[181]:

"13.3. We note that the majority of respondents to our COVID-19 consultation who expressed a view in this area also considered that now is not the right time to review the cost of capital. However, ***there were differences of opinion as to what would constitute an error of calculation, and what would constitute an erroneous approach to calculating a particular metric.***

13.4 In this final report we have updated only the 'vanilla' Weighted Average Cost of Capital (WACC) estimate from our provisional findings to reflect additional clarification from CAA and NERL on the measure of embedded debt to be used within the cost of debt analysis. ***We have not updated the market data*** *and have not made changes to the methodology that we applied in calculating the WACC,* ***based on the responses to our provisional findings or to our COVID-19 consultation. As a result, the approach in our final report does not reflect any assessment of the merits of the points raised in these responses."***

It is clear, therefore, that:

- the CMA recognise that significant issues have been identified with the methodology that it and Ofgem have used to estimate market parameters (TMR and RFR) which, if they are correct, would constitute errors; and

[179] The CMA does not appear to have considered the other two issues, as they make no comment on them in the NATS Provisional Findings.

[180] RIIO-2 Draft Determinations – Finance Annex paragraphs 3.16 to 3.19 and especially 3.21 to 3.22.

[181] NATS (En Route) Plc /CAA Regulatory Appeal Final report, 23rd July 2020, CMA. See also paragraphs 60 and 61:

"60. As explained earlier, given the ongoing uncertainties affecting the aviation sector, we have not refined our assessment in detail following our provisional findings, or made specific adjustments to take account of the impact of the COVID-19 pandemic, as this would not have allowed us to reach figures that accurately reflected the effects of the pandemic on determined costs. We also note that the majority of respondents to our COVID-19 consultation who expressed a view in this area also considered that now is not the right time to review the cost of capital.

61. Our final report therefore sets out the approach used to determine our provisional conclusions on the appropriate cost of capital for NERL. We updated only the 'vanilla' Weighted Average Cost of Capital (WACC) estimate from our provisional findings to reflect additional clarification from CAA and NERL on the measure of embedded debt to be used within the cost of debt analysis. We also calculated a pre-tax WACC to be used in setting charges, based on modelling used by CAA and NERL. We have not updated the market data or made changes to the methodology that we applied in calculating the WACC based on the responses to our provisional findings or to our COVID-19 consultation. As a result, the approach in our final report does not reflect any assessment of the merits of the points raised in these responses."

- the NATS Final Determination did not update the market data or methodology to take account of the responses to the NATS provisional findings, and as a result the approach and corresponding values of TMR and RFR in the NATS final Determination does not reflect any assessment of the merits of the points raised in these responses. Consequently the views of the CMA in the NATS appeal should not be seen as confirming Ofgem's position in the RIIO-2 DD, especially where the CMA did not consider some of the evidence they received in relation to the relevant market parameters (TMR and RFR).

As noted above, the estimate of TMR is also a point of consideration in the ongoing PR19 appeals by four water companies that are being considered by the CMA. The Provisional Determinations in these appeals are due to be published in mid-September and will give the CMA an opportunity to express a view on the evidence it has received in relation to market parameters in these appeals. As part of this response to the RIIO-2 DD, therefore, we also refer Ofgem to the submissions made by the ENA to the CMA on these market parameters (TMR and RFR) in relation to the PR19 appeal[182], as well as to the previous submissions that have been made to Ofgem.

In the RIIO-2 DD, as well as referring to the CMA process for the NATS appeal, Ofgem makes comments in response to the previous evidence it has received in relation to TMR, but Ofgem's comments on these points fail to address the evidence that was submitted.

DDM evidence

At paragraph 3.13 Ofgem say: *"For example, Oxera's view (7.0% to 7.5%) appears heavily influenced by its Dividend Discount Model (DDM), and its view on how to account for inflation"* – this does not reflect the content of Oxera's report: for example, see paragraph 2.2 in Oxera's 2019 update report[183] *"As in the Oxera 2018 report, and consistent with the methodology proposed by Ofgem, we rely on historical evidence from DMS as the primary source of input, together with the forward looking evidence derived from the Oxera implementation of the Bank of England DDM as a primary cross-check."* The Oxera report then provides extensive discussion of the evidence which shows that the historical dataseries of nominal returns should be deflated by the series of RPI values over the relevant timeframe to give a value of TMR real relative to RPI, to which the forecast RPI-CPIH wedge should then be added.

Then say: *"However, Oxera's DDM analysis follows the Bank of England (BoE) methodology, which focuses on changes rather than levels, which we noted in SSMD is less appropriate for our purposes. Oxera do not address in detail this issue or the alternative specification put forward by CEPA as presented in SSMC."* This issue does not mean that the Bank of England's model (or Oxera's DDM model which follows the same methodology) gives less accurate estimates of the levels of TMR than CEPAs. In fact, the failings in the assumptions used by CEPA which have previously been explained will mean that CEPA's model will underestimate TMR, and so gives an unreliable result. Pages 29 to 31 of the NGET/NGG response[184] to the Finance questions in the SSMC explained the concerns with CEPA's model and the assumptions it used, and Section 2.2.2 (page 19 to 21) in Oxera's November 2019 update report[185] not only provided an update of Oxera's DDM model (which uses the same approach

[182] https://www.gov.uk/cma-cases/ofwat-price-determinations: Energy Network Submissions dated 18.5.2020, 1.6.2020 and 19.6.2020.
[183] "The cost of equity for RIIO-2: Q4 2019 update", Oxera, prepared for Energy Networks Association, 29 November 2019
[184] National Grid's response to Ofgem's RIIO-2 sector-specific methodology consultation – Finance, available from Ofgem's website: https://www.ofgem.gov.uk/publications-and-updates/riio-2-sector-specific-methodology-consultation
[185] "The cost of equity for RIIO-2 Q4 2019 update", Oxera, prepared for Energy Networks Association, 29 November 2019

as the Bank of England's but also (on page 21) commented on Ofgem's/CEPA's DDM model and showed it had clear deficiencies.

NGET TMR paper comments

At paragraph 3.14 in the DD, Ofgem writes *"Similarly, NGET's paper on inflation focuses on one measure, often RPI, rather than of the 'best available' measure(s). In doing so, NGET add the forward looking RPI-CPI wedge to the historic real return, which therefore embeds the forecast RPI-CPI differential into 'historic' (sic) returns. This assumes, incorrectly in our view, that RPI best reflects investors' current expectations."* This paragraph mis-states and misrepresents the logic in our paper[186]. Contrary to Ofgem's claims, the paper seeks to establish which is the 'best available measure' for use when deflating the dataseries of historic nominal returns, i.e. the historic inflation dataseries which is most consistent and reliable, that can be used in the estimation of the long-run average real return, and does not presume that RPI best reflects investors' current expectations as the following extracts from the Context and Background Section on page 15 and the Executive Summary on page 5 make clear:

"Previous price controls across many regulated industry sectors in the UK have been set on a 'real' basis relative to RPI, but a number of regulators, including Ofgem and Ofwat, are now considering a switch from RPI to CPI (or CPIH). In considering this change, it is important to distinguish between two separate questions:

- *First, what is now the preferred inflation index (RPI, CPI or CPIH) which should be used to inflate future allowed returns, RAV values, revenues, etc during a price control*
- *Second, what is the most robust basis for setting the allowed 'real' return relative to this preferred inflation index.*

These two questions need to be considered and answered separately - i.e. the answer to one does not depend on the other - and it is the second of these questions that is the subject of this report. Although Ofgem has expressed an intention to switch to CPI (or CPIH) for inflating future revenues, the second question remains open. Ofgem's main method for estimating the required level of equity returns is the CAPM, and so a value for the Total Market Return (TMR) parameter expressed relative to CPI (or CPIH) is now needed."

and:

"*Ofgem has also decided to set future price controls including RIIO-2 relative to CPI (or CPIH), rather than RPI as in the past, and so a value of TMR relative to CPI (or CPIH) is now needed. Estimates of the average historical realised TMR are typically made first on a nominal basis, and this can be used to give an estimate on a real basis relative to CPI2 in 2 main ways, either:*

- *by subtracting the historical average long-run rate of RPI inflation over the relevant period from the average nominal return, to give a real return relative to RPI, and then adding the expected forward-looking 'wedge' between RPI and CPI to convert the result to a real return relative to CPI; or*
- *by subtracting the historical average long-run rate of CPI inflation over the relevant period from the average nominal returns, to give an estimate of the real return relative to CPI directly.*

Whilst the second of these approaches may be the more direct, the uncertainty in the expected average forward-looking wedge between RPI and CPI is low (subject to any material changes in their calculation methodology), and so ***which of these methods is more robust and accurate will depend primarily on which of the historic data series for RPI and for CPI is***

[186] "Total Market Return: the consistency of long-run CPI and RPI inflation series in the UK, and their relative suitability for use in calculating the actual historic long-run average equity market return in the UK on a 'real' basis", National Grid, 23 January 2020

***more reliable and consistent when considered across the full time-frame covered by the historic return dataset**.*"

In the DD, Ofgem do not seem to engage with the main reasoning, analysis and evidence contained in our TMR paper[187], and neither have Ofgem addressed the deficiencies in the Ofgem approach to estimating TMR from long-run average returns which were identified in the paper at paragraphs 16 to 30. Ofgem do provide limited further comments on our TMR paper in Appendix 3 of the DD on page 194, but without identifying any real failings with it

"*The main issue with NG's analysis is that it embeds RPI inflation into the ex-ante return, even though RPI is a discredited measure of inflation*." Ofgem appears here to be referring to concerns with RPI as a measure of ongoing or future inflation as expressed, for example, in the Johnson Review in 2015. These concerns are not, though, relevant to the question of which inflation dataseries (RPI or CPI) is more consistent and reliable over the period from 1900 to 2020, which (as explained in our paper) should determine whether:

- nominal returns are deflated by CPI to give an estimate of real returns relative to CPI in a single step, or
- deflated by RPI, to give a value to which the expected forward-looking 'wedge' between RPI and CPI is then added to convert the result to a real return relative to CPI.

Significant reservations have been identified with the CPI back-series which Ofgem rely on to deflate past nominal returns, which neither Ofgem nor any of Ofgem's consultants have tried to address:

- Paragraphs 33 to 36 of our TMR report considered the values used in the CPI dataseries from 1899 to 1949, which are deflators calculated from estimated National Accounts published by Feinstein (1972). Amongst other factors, these paragraphs observed that:
    - the fact that the deflators derived from Feinstein's estimated National Accounts are used for the Millennium databook's CPI series up to 1949 cannot be considered evidence that the Bank of England considered them a reliable estimate of CPI, especially when these same values were also used in the corresponding RPI series in these years. Rather, it merely indicates an absence of any other known sources of CPI values prior to 1950, and by itself it says nothing about whether the values better represent RPI or CPI. Furthermore, the Millennium dataset contains a series of caveats that make clear the values within it cannot be relied on without carefully reviewing them and the sources from which they are taken. For example, the spreadsheet says that it should be viewed as "*work in progress*"; "*the Bank of England makes no representations or warranties as to the accuracy or completeness of the information*"; and perhaps most importantly "*users are always advised to consult the original sources as a crosscheck*".
    - the ONS had recently confirmed to Oxera that these values are likely to be based on underlying series constructed using a methodology comparable to RPI, and so the consumers' expenditure deflator series would contain the upward influence of the RPI formula effect, and so would overstate CPI inflation
    - the ONS's "Consumer Price Indices Technical Manual" (2014 edition), explains that the deflators derived from Feinstein's (1972) national accounts are used by

[187] "Total Market Return: the consistency of long-run CPI and RPI inflation series in the UK, and their relative suitability for use in calculating the actual historic long-run average equity market return in the UK on a 'real' basis", National Grid, 23 January 2020

the ONS in a longer-term series that was produced for longer term comparisons of RPI rather than CPI.

 - This manual also explains in the Retail Price Index chapter (Chapter 10) that RPI is preferred to CPI for making long-term comparisons of the purchasing power of the pound.
 - The deflators derived from Feinstein's estimated national accounts have in the past been consistently interpreted as comparable to RPI, not only by the ONS, but also by the House of Commons library and the Bank of England: this corroborates the view that the deflators can be seen as comparable to RPI rather than CPI.

- Paragraphs 37 to 42 of our TMR report then considered the values that are used in the CPI dataseries from 1950 to 1988. These values are an indicative 'work in progress' series of 'modelled estimates' of CPI produced in 2013 by the ONS. Multiple reservations and concerns have been expressed regarding these values, including in the 2014 paper itself[188] which published and described this backseries; in other ONS documents; and in a recent book on the history of inflation measures which was written by the authors of the ONS's paper. For example:
 - the Introduction to the ONS's paper noted that: "***The method provides only approximate results*** *and there is no way to determine how accurate our method is as sufficient data to calculate the CPI do not exist prior to 1987*."
 - On page 7, at the start of Section 5 which gives an "Analysis of Backcast Series – Component Indices", the ONS's paper explains that "*It is difficult to assess the accuracy of the series, as the true CPI can never be known. For that reason, it is also worth emphasising that these modelled estimates can only be considered as* ***broad indications*** *of the level of the CPI series* ***at best*** *and caution should be exercised when using these series*."
 - On page 10 the ONS paper notes that "*... Other models may produce alternative formula effect backcasts. ... Hence there are many ways in which the modelling approach taken might be augmented or re-designed with alternative series produced. Several other issues also present themselves; ...* ***By pointing out these choices we hope to emphasise that the series constructed here represents only one realisation of a back series of this length for CPI.***"
 - wherever the 2014 edition of the ONS's "Consumer Price Indices Technical Manual" refers to the CPI modelled backseries, it observes that "*these are indicative, modelled figures which should be treated with some caution*", in marked contrast to the discussion of the Retail Price Index in Chapter 10 in the Technical Manual, which explains that RPI is preferred to CPI for making long-term comparisons of the purchasing power of the pound.
 - Furthermore, the authors of the ONS's 2013 paper "Modelling a Back Series for the Consumer Price Index" (i.e. O'Neill and Ralph) have more recently co-written a book on the history of Inflation. It is telling that in this book[189] they contrast the reliability of the historic timeseries for RPI and CPI in the following way: "*There is another, different attribute of the [RPI] measure that came out of the RPI consultation – its value as a long-running measure produced on similar terms. The CPI, in contrast, was only introduced in 1996. …*"

[188] O'Neill and Ralph, "Modelling a Back Series for the Consumer Price Index", ONS, released July 2014: https://webarchive.nationalarchives.gov.uk/20151014001752/http://www.ons.gov.uk/ons/rel/cpi/modelling-a-back-series-for-the-consumer-price-index/1950---2011/index.html

[189] "Inflation History and Measurement", O'Neill, Ralph and Smith, 2017, ISBN 978-3-319-64124-9, published by Palgrave Macmillan.

- In addition, a recent update on CPIH and CPI backseries from the ONS[190] has reinforced that the CPI backseries cannot be relied upon, and furthermore the ONS is going to update these values (though it is unclear whether the resulting update will itself be able to give robust and reliable figure for CPI back to 1947): *"The ONS previously published indicative modelled estimates for the CPI between 1947 and 1987. These estimates are for analytical purposes only and are not intended for official uses."*

- In conclusion, the references and information reviewed in this section of our TMR report show that there are only reliable values of CPI from 1988 onwards, with significant doubts over the values used in the Millennium databook's CPI series for 1900 to 1949 and for 1950 to 1988.

"*NG's argument appears to hinge on there being a consistent and perfect single measure of inflation for more than 100 years."* It is clear from reading our TMR paper that it does not rely on there being a single, perfect measure of inflation for more than 100 years, as Ofgem claim. Instead, it simply adopts the obvious starting point that it is more reliable to deflate the nominal return dataseries using a more consistent and reliable dataset than a less reliable one. The paper demonstrates that the available RPI dataseries since 1900 is more reliable than the available CPI series, given the sources used for the CPI series, and it then backs up this evidence with some empirical numerical analysis that shows that the Bank of England's Millennium databook CPI dataseries (both the 'original' series and the 'preferred' series) do not accurately or reliably give the values that CPI would have had if it actually had been measured over the long-term (i.e. from 1900 to 1988, where 1988 is the first year for which reliable CPI values actually exist). In contrast, this analysis adds support to the view that the Millennium databook's long-run RPI series does provide a much better representation of RPI as it is now calculated across the full period under consideration (1899 to 2018).

"The absence of this does not invalidate using the best available measure for each period of history, as implied by NG." This is not what we imply. To the contrary, there would be significant problems in using different measures of inflation for different periods of history, as it would not be clear how the resulting 'real' return should be interpreted – it would be a value relative to neither RPI nor CPI.

In summary, although Ofgem has decided to transition to a CPIH indexed price control, it is still necessary to decide what long-term historic inflation series back to 1900 or longer should be used to deflate the historic series of nominal equity market total returns. This should be the most accurate and reliable inflation series over this long timeframe. We and economic consultants (Oxera, Nera and Frontier)[191] have considered whether CPI inflation should be used as a basis of setting real returns with reference to data published by the Bank of England (BoE) in the Millennium dataset. The conclusions of these reviews have consistently been that the historical RPI series is more reliable than the alternative back-cast CPI series. The reasons for this are set out in detail in the relevant economic studies but in summary are that:

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[190] ONS statement "Developing CPIH and CPI historical estimates between 1947 and 1987", 10/10/2019, https://www.ons.gov.uk/news/statementsandletters/developingcpihandcpihistoricalestimatesbetween1947and1987

[191] See for example "Review of UKRN Report Recommendations on TMR", NERA prepared for the Energy Networks Association, 20 November 2018; "Inflation in the context of real TMR", a note for the Energy Networks Association prepared by Phil Burns, supported by Mike Huggins, Rob Francis and Michael Yang of Frontier Economics, 13 March 2019; and "The cost of equity for RIIO-2", Q4 2019 update, Oxera prepared for Energy Networks Association, November 2019

- The authors of the CPI dataset from 1950 to 1988 expressed significant reservations over the data when it was published. As a result, reliable CPI values only exist for the period since 1989. Moreover, the underlying data that would be needed to calculate reliable values of CPI for earlier timeframes has not even been retained by the ONS.
- Oxera's latest cost of equity update report explains a further concern with the CPI backcast, i.e. the CPI values from 1950 to 1988[192]: "*We requested the data and code underlying the CPI backcast. The ONS was unable to locate the information used to construct the historical CPI estimates, and has been unable to replicate them. The ONS is currently revising the backcast of historical CPI. We consider that it would be inappropriate to switch this estimated historical inflation series for setting a price control when the series is under revision and may be subject to error, given that the results cannot be reproduced*."
- The RPI and CPI dataseries used the same values as each other from 1900 to 1948, but the ONS have confirmed to Oxera[193] that these values are likely to be based on underlying series constructed using a methodology comparable to RPI, and so the consumers' expenditure deflator series would contain the upward influence of the RPI formula effect, and so would overstate CPI inflation. It follows that these deflator values cannot be considered to give an indication of CPI values during these years, but can be considered representative of RPI[194].
- The available evidence shows that the RPI inflation dataseries is more reliable and consistent over the long-term than the available CPI dataseries, and on this basis it should be used when estimating the historical realised market return to give a real value (relative to RPI). An estimate of the real TMR relative to CPI can then be derived from this by adding the expected forward-looking difference between RPI and CPI.

TMR Issue 2 – TMR should use a discount rate at least as high as the historical arithmetic average to reflect investors discount rate approach for capital budgeting

The second issue concerns whether TMR estimates should be based on a long-run return averages that are calculated on a geometric or arithmetic average basis. This has received widespread academic attention over many years.

At paragraph 3.15 in the DD, Ofgem refers to this issue in the following way "*Both Oxera and NGET rely on arithmetic averaging, with reference to research by Cooper (1996). However, this reliance does not address the fact that most investment professionals focus on the geometric return over the investment horizon. Further, Blume (1979) has shown that if the holding period is longer than one year, the arithmetic mean of one-year returns is an upwards-biased measure of the true expected return. We remain unconvinced that arithmetic averaging, particularly if it is unadjusted, is more reliable than adjusting geometric means upwards, in line with our SSMD view*."

From this description, it appears that Ofgem may not have fully understood the issue. The ENA, supported by Oxera, has recently explained the issue to the CMA in a submission to the PR19 appeal, and to assist Ofgem we bring this explanation to their attention[195]. This reference explains the following:

[192] "The cost of equity for RIIO-2 Q3 2020 update", Oxera prepared for the Energy Networks Association, September 2020, page 17
[193] Ibid., page 17
[194] This is consistent with the use of these deflators derived from Feinstein (1972) in the ONS's own long-term RPI series, as described for example in "Consumer Price Inflation since 1750", by Jim O'Donoghue and Louise Goulding (ONS) and Grahame Allen (House of Commons Library), from ONS's Economic Trends 604 (March 2004)
[195] See pages 8 to 9 in the ENA submission to the PR19 appeal to the CMA, 19.6.2020, https://assets.publishing.service.gov.uk/media/5eeb57fae90e07644fae4218/Energy_Networks_Association__3_.pdf; see also Professor Stephen M Schaefer, London Business School, Comments on CMA views on Estimating

- Ofgem's approach to averaging the historical returns, like that of Ofwat, addresses the wrong question, resulting in an incorrect downward biased estimate of the cost of equity. Ofgem, like Ofwat in PR19, "*implicitly defines the question as 'what return do investors require for investing in equities?' The JKM and Blume estimators used by the CMA can be used to answer this question, and correctly provide estimates that are slightly lower than the arithmetic average. However, the relevant question for setting a price control is 'what rate do investors use to discount future cash flows?' Using the JKM and Blume estimators to answer this question results in estimates that are more biased than simply using the arithmetic average, because the JKM and Blume estimators adjust in the wrong direction (i.e. down).*"
- Cooper (1996) demonstrated that the discount rate investors should use to give an unbiased estimate of the present value of future cash flows, will assume a TMR at least as high as the arithmetic average of historical returns. As the horizon for investment appraisal extends, the TMR must be further increased above the arithmetic average.
- Professor Stephen Schaefer set out his reflections on the CMA's approach to establishing expected returns in its NERL Provisional Findings in a report provided to the CMA in the NERL redetermination process[196]. Professor Schaefer observes that[197]:

  "*estimation error in the expected return will produce a positive bias in both the expected future value of an investment portfolio and in the present value of a future cash flow. Since future value increases with the expected return, adjusting for a positive bias in the case of compounding means using a lower expected return. However, since present value decreases with the expected return, adjusting for a positive bias in the case of discounting means using a higher expected return*",

  and:

  "*To allow both discounters and compounders to make consistent, unbiased estimates, all the CMA needs to do is to provide an unbiased estimate of the arithmetic return*".
- Oxera's November 2019 update report[198] explained that the source of the bias is the convexity of the function used to estimate the arithmetic and geometric average discount factors, which results in the estimated expected value of the discount factor being higher than the true expected value. As the discount rate is the inverse of the discount factor, the bias is inverted and the estimated value of the discount rate will be lower than the true expected value.
- Oxera's work shows a further shortfall for the difference between the correct value and the arithmetic average of 18bps at a ten-year investment horizon and 35bps at a twenty year investment horizon. The number continues to increase for investment horizons longer than 20 years[199].
- This issue has been considered further in a February 2020 paper by Oxera and Professor Schaefer[200]. The main conclusion of the paper is that "*the discount rate that is required to give an unbiased estimate of the discount factor (i.e. of present value), for use in capital*

Expected Returns, 15 April 2020; and see also Oxera (2020), "Deriving unbiased discount rates from historical returns", which incorporated Professor Stephen M Schaefer, "Using Average Historical Rates of Return to set Discount Rates"

[196] Professor Stephen M Schaefer, London Business School, Comments on CMA views on Estimating Expected Returns, 15 April 2020.

[197] NATS En-route plc (NERL) Price Determination: Submission by ENA in response to the CMA's Provisional Findings, listed as ENA submission of 24.4.20 on the CMA's website, page 8

[198] 'The cost of equity for RIIO-2: Q4 2019 update', Oxera prepared for Energy Networks Association, 29 November 2019, Page 18.

[199] *Ibid* Table 2.3

[200] Ofwat Price Determinations: Further submission by Energy Networks Association, listed as ENA submission of 19.6.20 on the CMA's website, see page 9; taken from
Oxera (2020), "Deriving unbiased discount rates from historical returns", which incorporated Professor Stephen M Schaefer, "Using Average Historical Rates of Return to set Discount Rates"

> *budgeting, will be at least as high as the arithmetic average of historical returns. It is this value that regulators must estimate in setting an allowed return on the RAV. As the investment horizon extends, the discount rate must be further increased above the arithmetic average".*

In the SSMD, Ofgem's range for TMR was 6.25% to 6.75%, consistent with that in the DD, and within a wider initial range from 6% to 7%. The derivation of this value was illustrated in Ofgem's SSMC in Figure 18, which showed that an 'uplift' of 0.77% was added to the geometric average in calculating the bottom of the range. The corresponding uplift at the top of the range was 1.77%. The middle of Ofgem's range appears to correspond to a deduction of c.0.5% to the arithmetic average, in contrast to the correct approach as explained above which would instead require an addition of 0.18% (for a 10-yr horizon) or 0.35% (for a 20-year horizon), so this incorrect averaging approach alone results in Ofgem's TMR estimate being c.0.75% (i.e. 0.68% to 0.85%) too low depending on the investment horizon considered.

TMR Issue 3 – the averaging period used by Ofgem gives the lowest TMR results

When calculating an estimate of TMR from data for the average realised market returns over the long-run, it is necessary to decide the length of the averaging period that should be used. Estimates of returns have often been based in the past on averages from 1900 to the present day. However, there is nothing special about 1900 as the start date for the averaging period and no reason to assume that data prior to this point is any less relevant. Ofgem themselves have previously recognised this[201]. Conversely, if data prior to 1900 is to be disregarded as being less relevant, the data in the first decades of the 20th century might equally be excluded in working out the average returns.

Our TMR report[202] considers this issue on pages 54 to 56. It includes tables which show that use of either an earlier or later starting date for the long-run averages leads to higher values of average realised return. As there is no rational justification for choosing a start date for the averaging which gives the lowest value of long-run averages, it is therefore clear that use of the averages from end 1899 only does not give a balanced view of the true level of the long-run realised average return. Introducing bias in this way by ignoring relevant evidence for no good reason constitutes an error in methodology. If the evidence that is now available that relates to different averaging periods is taken into account, the overall geometric average should be increased by at least 0.3% to 0.5%.

As described above, using 1900 as a starting point for the long-run average of market returns in the UK gives values which are, or very close to, the lowest average return, whereas averaging over longer or shorter periods gives higher values. Our TMR report also shows that there is a similar pattern when looking at total equity market returns from the USA over longer or shorter averages than from 1900. This corroborates the pattern of long-run averages for the UK that is described above, and so confirms that bias would be introduced if only the value of the long-run average return since 1900 is considered.

The relevance and impact of considering different averaging periods can also be seen to be consistent with a 2019 report by Aon[203], referred to as consultancy report 17 in Ofgem's SSMD Finance Annex. Ofgem notes that one of the authors of this report was Derry Pickford, who wrote the Appendix D in the earlier March 2018 UKRN report, which was the section of the UKRN report which considered the different inflation measures in the Bank of England's Millennium databook, and so led to Ofgem's proposed approach of deflating historic nominal

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[201] For example, Ofgem said on 17th February 2014 in the "*Decision on our methodology for assessing the equity market return for the purpose of setting RIIO-ED1 price controls*" that "*the most objective evidence for prospective market returns is the level of returns achieved by investors in equity markets over the longer term, going back as far as the start of the 20th century or even earlier in the 19th century*."

[202] "Total Market Return: The consistency of long-run CPI and RPI inflation series in the UK, and their relative suitability for use in calculating the actual historic long-run average equity market return in the UK on a 'real' basis", National Grid, 23 January 2020

[203] Aon report "Is the UK an "averagely lucky country?" by Derry Pickford and John Chung, 6th March 2019

returns using the BoE's CPI series. The Aon report concludes that the best estimate for the long-run realised return is 6.5% real on a geometric average basis. (Note that Ofgem incorrectly interprets this 6.5% figure in their May 2019 SSMD Finance annex to be an arithmetic average - see Ofgem's first comment in response to Consultancy report 17 in the SSMD Finance Annex - and so appeared to view the report as supporting their 6.25% to 6.75% TMR range, when in fact it is a geometric average and so supports a range that is appreciably higher than this.) Even using Ofgem's value for the uplift that should be added to geometric return averages when estimating TMR (0.77%to 1.77%), once this National Grid is added to the geometric average value in the Aon report, it gives a range from 7.3% to 8.3% (relative to CPI).

Ofgem does not address the issue of averaging length in the main body of the DD Finance Annex, but does consider it briefly in Appendix 3, in commenting on our TMR report. Ofgem's response is that *"We have consistently used the period back to 1900 when estimating TMR, using evidence from DMS. We consider that this represents a suitable time horizon, and have addressed in SSMD why a longer period may suffer from survivorship bias. A shorter period would seem to be selective, unless there is a good reason to believe earlier data is unrepresentative."*

In the SSMD Ofgem made the following comments on this issue:

3.76 We were not persuaded by NG's argument that we should use different outturn periods for estimating the TMR. NG suggested that we should use data from 1950 onwards. However, of the 66 years from 1950 to 2016, 51 have had positive returns (77% of the sample) - therefore, reliance on this period alone, as suggested, without good reason for discarding the other data, seems unduly biased.

3.77 We also note that to focus on the sample from 1900 is consistent with our approach for RIIO-1. In this period, we find 86 years of positive returns from the 117-year sample (73%) – therefore on this basis, it appears that the 20th century has more positive bias than negative. This also makes it doubtful that there may be a disaster-bias by including the first 50 years of the 20th century, as argued by AON.

3.78 We do note however that AON's argument appears to be partly based on the thesis that negative returns can be more impactful than the positive returns. However, AON did not demonstrate clearly that this theory is unduly affecting the period from 1900 onwards.

3.79 Similarly, we were not convinced that we should increase our data sample to include most of the 1800s - it is widely known that data going back so far in history may not be reliable. For example, Jorion and Goetzmann (1999) argue:

> *"Long-term estimates of expected return on equities are typically derived from U.S data only. There are reasons to suspect that these estimates are subject to survivorship, as the United States is arguably the most successful capitalist system in the world…. The high equity premium obtained for U.S. equities appears to be the exception rather than the rule."*

None of Ofgem's observations provide a valid reason not to consider the impact of different averaging periods, as we explain below:

- The observations that *"We [Ofgem] have consistently used the period back to 1900 when estimating TMR, using evidence from DMS."* and *"We [Ofgem] also note that to focus on the sample from 1900 is consistent with our approach for RIIO-1."* might have some merit if Ofgem were adopting a consistent approach in other aspects of TMR estimation. As it is, Ofgem is happy to change the methodology in other respects, such as to switch from use of a long-run RPI dataseries to use of a long-run CPI series when deflating past nominal returns, and so cannot reasonably argue that only the average since 1900 can be considered because this is the approach that has been used previously.
- Ofgem's objection that *"a longer period may suffer from survivorship bias"* can be seen to be taken from a very old (1999) paper that was commenting on the limitations, at the end of the 20th century, that were caused by long-term data being typically only available for

the US. Since long-term return data is now available for the UK, and this is the data that we have primarily referred to in relation to this issue, this concern is no longer relevant.

- We are not suggesting that Ofgem should use data from 1950 only (and did not previously suggest this). Rather, we are highlighting that to focus on the long-run average across a single timeframe only (i.e. since 1900), where both longer and shorter averages give higher values, introduces a downward biased estimate.
- It is not clear on what basis Ofgem consider that, when considering returns from 1900, it is a concern that *"In this period, we find 86 years of positive returns from the 117-year sample (73%) – therefore on this basis, it appears that the 20th century has more positive bias than negative."* Since average returns are positive, it would be expected that there would be more years of positive returns than negative, and a histogram of average real returns in each of the 120 years is close to symmetric around the average value. In any case, even if there are many more years of positive returns than negative, this does not mean there is a positive bias: the average is just that, an average, and whilst Ofgem's observation might be suggesting that the distribution of returns is not completely symmetrical this does not mean that the average is biased.
- Ofgem's comments on Aon's report do not fully address the conclusions reached by Aon, but in any case are not relevant to main concern being raised here, which is that to choose the averaging length that gives lowest averages only, whilst disregarding both longer and shorter averages which gives higher values, gives a downward-biased estimate of TMR.
- We accept that increasingly old data may be less reliable, but this concern would also mean that, for example, the data between 1900 and 1920 is likely to be less reliable than that in later years. On this logic, more weight should be attached to the higher average real returns starting from 1909, 1919, and 1929 rather than considering just the lowest average value starting in 1899. A preference to avoid use of less reliable data would also apply in other areas, for example, the available inflation data series are likely to be more reliable as you move forwards in time. On this basis, if Ofgem are concerned about using less reliable older data, more focus should be placed on averages since 1950, for which official 'RPI' values do exist, and place less weight on data prior to 1950 for which no official inflation data has ever existed. The period since 1950 would still give a long-run average covering 70 years. This is not our main argument here though: rather, we point out that longer or shorter averages give higher values than the average return since 1900, and to place full reliability on data from 1900, considering it to be equally as good as return information in more recent years, whilst completely disregarding and giving no weight at all to any information prior to 1900, is not justified.

TMR Issue 4 – Ofgem's estimate is not based on return across the whole equity market from 1899 to 1954

Even if the calculated value of realised real return is based on averages since the end of 1899 only, using the DMS/Credit Suisse databook values of nominal returns, deflated by the historic RPI (or CPI) inflation series, there is a further reason to think that the result will be an underestimate of the average realised return on the whole of the UK equity market. This is because the DMS estimate of equity returns in the UK is based on the returns of the 100 largest companies only from 1899 to 1954. The total returns on these largest companies would have been expected, on average, to be lower than those on smaller companies: this widely recognised difference is known as the 'size effect'. As a result, the UK returns given by the DMS/Credit Suisse databook for these 55 years are not really a measure of Total Market Return in the UK during these years but would be expected to underestimate it.

Further information and an estimate of the size of the impact that the limited coverage of the DMS returns information from 1899 to 1954 would have is given in our TMR report at pages 56 and 57. Ofgem does not address this coverage issue in the main body of the DD Finance document, but does consider it briefly in Appendix 3, in commenting on our TMR report. In this

Appendix Ofgem say "*We have based our assessment on available evidence and are not aware of any source of downward bias in the available data as argued by NG*." This does not address the point at all: our TMR report identified the issue, and provides documentary evidence and references to support the point and show that it is not immaterial. In the absence of any observations at all to the contrary, it would be an error of fact and of methodology to ignore this source of downwards bias.

Appendix 3: Further detail on our response to Ofgem's proposed debt beta methodology

As our answer to question FQ5 explains, the notional equity beta needs to be calculated from raw observed beta values for listed companies which generally have a different gearing level from the notional gearing level chosen for a price control, and will inevitably have different actual gearing levels from each other. In order to compare these values and make these calculations, a debt beta value needs to be assumed, and in the calculations for the DD Ofgem uses a debt beta of 0.125.

The DD briefly refers to studies[204] that suggest debt beta values greater than zero should be assumed in price controls at paragraphs 3.36 to 3.39; in Table 16, where Ofgem's chosen 0.125 value of debt beta for the calculations in the DD is described as '*Ofgem judgement*'; and in Appendix 3, where Ofgem responds to NERA's and Oxera's use of a lower debt beta value of 0.05 in the following way:

"*We are not persuaded that we should reduce our estimate of the debt beta. The UKRN has published research on the debt beta which supports our current view. We note a low debt beta implies a larger boost to both the cost of equity, and the cost of capital, as gearing increases. We note that NERA's debt beta assumption does not align with Oxera's direct estimation value of 0.2 for National Grid's debt beta, as noted in the UKRN debt beta study."*

"Oxera's view on debt beta seems heavily dependent on only one method of estimation, an indirect method. Oxera's other work however shows that a direct estimation approach for National Grid indicates a statistically significant debt beta of 0.2, as per it's March 2019 report: 'If (again for July 2013 – June 2018) we simply regress returns on a portfolio of National Grid debt against the FTSE we obtain a coefficient of 0.20 (t = 2.48)'. Oxera's estimates, from zero to 0.2, span our proposed debt beta estimate of 0.125. It is not clear to us why Oxera prefer a lower debt beta estimate, given its own findings of higher values."

Importantly, Ofgem appears to have misunderstood the context in which the 0.2 figure which they refer to was included in Oxera's report. Oxera did not reach "*findings of higher values*", and in stating that "*It is not clear to us why Oxera prefer a lower debt beta estimate"* Ofgem are ignoring the more detailed results and discussion in Oxera's report. Whilst Oxera's report did quote a value of 0.2 in one place, as noted by CEPA, this was merely the result of a simple direct regression, and as the relevant paragraph itself then explained this simple regression value does not reflect the credit risk of National Grid. Instead additional factors need to be included in the regression, as Oxera's report explained. When applying regression-based methods, it is important to control for interest rate risk, as otherwise the resulting debt beta estimate would capture risks over and above credit risk, resulting in a biased (i.e. inflated) estimate. This is illustrated by the related observation in the previous paragraph of Oxera's report that:

"... in the five years ending June 2018, the correlation between the FTSE and the Barclays 7-10 year UK government bond index was positive (around 0.25). Thus, over this period, riskless debt has a positive beta against the FTSE but this beta clearly has nothing to do with default risk. Since debt of National Grid and the listed water companies is fairly low risk, part of its sensitivity to equity will simply reflect the correlation between riskless debt and the equity market."

We therefore refer Ofgem back to Section 4 of Oxera's earlier report[205] so they can properly review the evidence and explanation provided, which reached the conclusion *(on page 26)* that

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[204] "Considerations for UK regulators setting the value of debt beta", CEPA report for the UK Regulators Network, 2 December 2019; and Oxera's 20 March 2019 report "Review of RIIO-2 finance issues: The estimation of beta and gearing) prepared for the ENA.

[205] "Review of RIIO-2 finance issues - The estimation of beta and gearing", Oxera, prepared for Energy Networks Association, 20 March 2019

"*Current evidence supports debt beta of 0.05 instead of Ofgem's range (0.1–0.15). ... We have provided recent capital market evidence, prepared with Professor Schaefer, to substantiate that a debt beta assumption of 0.05 is appropriate in determining allowed returns for RIIO-2.*"

Oxera further considered debt beta evidence in their subsequent November 2019 "Cost of Equity Update" report[206] in Section 3.2.5. After reviewing the evidence, Oxera reached the view at the end of this section that "*our proposed estimate of 0.05 is a conservative assumption for the debt beta in RIIO-2.*" In other words, the evidence might support lower values.

As part of the evidence considered in this November 2019 report, Oxera reviewed academic and industry evidence reported by Ofgem in the SSMD, based on analysis from NERA, as well as two additional more recent observations added by Oxera (see Figure 3.1 in Oxera's report). Only two of the references considered by Ofgem supported values at or approaching 0.2:

- The first referred to a Fama and French paper from 2002, but this paper does not actually seem to suggest a value for debt betas. Rather, the actual source cited for the Fama and French derived estimate in NERA's report which Ofgem referred to is a Fama and French paper from 1993, but in that paper, table 7b suggests that the debt betas of investment grade bonds are between –0.02 and 0.02.
- The second is the well-known Brearley & Myers "'Principles of Corporate Finance" textbook, but this gives no evidence to support this range, as the authors simply make a general and non-specific observation that '*debt betas of large firms are typically in the range of 0 to 0.2*'.

The other sources included in the NERA reference that Ofgem referred to suggested debt beta values of 0.04 (Schaefer & Strebulaev 2008), 0.125 (Damodaran 2012) and 0.05 to 0.1 (Brattle Group 2016). Moreover, one of the additional references identified by Oxera in the November 2019 report was to a more recent estimate of 0 from Damodoran (in 2019). These sources would therefore, on average, support a value of c.0.05. We also note that in their more recent report for SPT "November 2019 – Cost of Capital for SPT"[207], which is considered by Ofgem in Appendix 3 of the DD, NERA now support use of a debt beta value of 0.05.

It is, therefore, unclear what evidence Ofgem is now using to support the debt beta value of 0.125 that was used in the DD. The value of 0.2 referenced to Oxera was taken out of context and was not an estimate of debt beta; the evidence referred to in the SSMD that supported higher beta values has been shown to be flawed; and both the remaining evidence in SSMD and the more rigorous and sophisticated studies carried out by Oxera suggest that the debt beta value should be 0.05 or less. In the absence of any evidence to support a debt beta of 0.125, it would be an error for Ofgem to use this value in Final Determinations, and a value of 0.05 should be used instead.

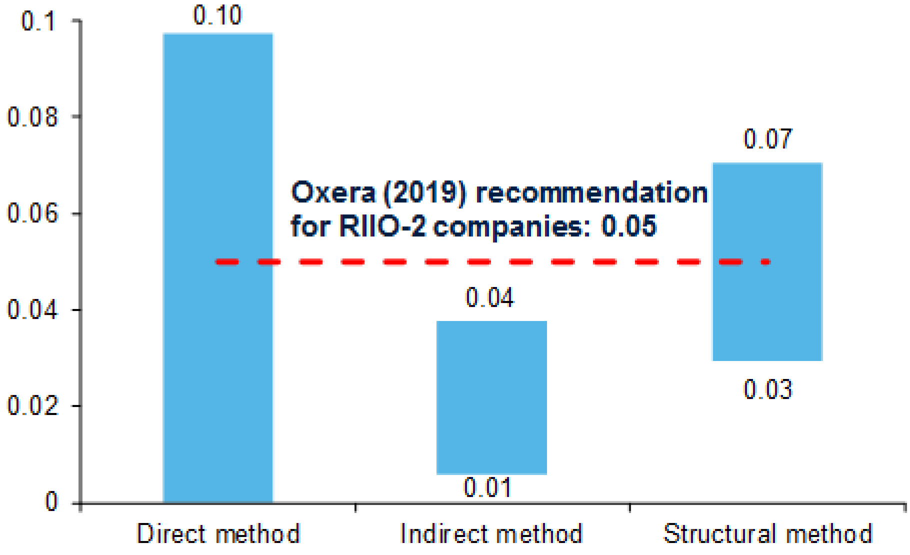
More recently still, Oxera have further considered the evidence for debt beta values in some depth using a range of estimation methods in Section 3.2.2 of their latest cost of equity update report[208]. These include CEPA's application of the structural method in the December 2019 report for the UKRN '*Considerations for UK regulators setting the value of debt beta*'. Oxera identify two errors in CEPA's calculations, and when these are corrected this method too gives an estimate debt beta of 0.05[209]. Oxera also address CEPA comments on the various estimation methods in CEPA's report for the UKRN, and note, for example, that CEPA failed (when comparing the indirect regression-based approach to direct regression-based methodologies) to reflect the need to control for interest rate risk when estimating beta using a regression-based method. In relation to the decomposition method, Oxera review the

[206] "The cost of equity for RIIO-2 Q4 2019 update", Oxera, Prepared for Energy Networks Association, 29 November 2019
[207] https://www.spenergynetworks.co.uk/userfiles/file/RIIO-T2_Annex_9_SPT_WACC_report.pdf
[208] "The cost of equity for RIIO-2, Q3 2020 update", Oxera prepared for Energy Networks Association, September 2020
[209] Ibid., Figure 3.4

advantages and problems of the approach, and conclude that "*As a result of these disadvantages, the decomposition approach could be viewed as an inferior version of the structural methods cited by CEPA. This is because unlike the decomposition method, structural methods have strong theoretical foundations, have been shown to approximate the regression estimates correctly, and can account for the relationship between gearing and debt beta. Additionally, both approaches require a similar number of parameters to be specified. Therefore, we would recommend that regulators place more weight on the structural method and the regression-based methods than the decomposition approach*."[210]

The evidence for debt beta values from the different methods is summarised in the chart below taken from Oxera's new report[211]

Figure 28 Evidence on Debt Beta



Oxera conclude that the estimates from direct and indirect regressions as well as from the corrected version of CEPA's structural method support a debt beta assumption of 0.05 for regulated network companies. This addresses Ofgem's comment in the DD that *"Oxera's view on debt beta seems heavily dependent on only one method of estimation, an indirect method."*

Finally, on debt beta, at paragraph 3.70 Ofgem suggests that its observation that "*common approaches to re-gearing asset betas have the effect of increasing the overall WACC estimate*" as assumed gearing increases, which is exacerbated at lower levels of debt beta, casts *"further doubt over arguments that we should assume a low value of debt beta."* However, as noted in our discussion of Risk Free Rate in our response to FQ9, and in our response to question FQ7, once Ofgem correct their error in estimating the Risk Free Rate that is used in the CAPM formula (to take account of the unique characteristics of sovereign bonds and the gap between corporate and sovereign risk-free financing rates), which then leads to a RFR value that is significantly higher than the value in the DD, this relationship between gearing and overall WACC which Ofgem refer to is effectively eliminated even with low values of debt beta. Thus, the observation referred to by Ofgem at paragraph 3.70 does not actually support higher values of debt beta than 0.05.

[210] "The cost of equity for RIIO-2, Q3 2020 update", prepared for Energy Networks Association, September 2020, page 41
[211] Ibid, see Section 3.2.2 and Figures 3.1 to 3.4 in particular for further details