Section D: Ensuring efficient financing.

6 Ensuring efficient financing

Gas networks face unprecedented uncertainties and challenges over the RIIO2 period and beyond in relation to the decarbonisation of heat and the journey to delivering net zero, whilst maintaining a safe, reliable and efficient network. It is essential that the RIIO2 price control creates the conditions to attract levels of investment required in our networks to meet these challenges. Having a finance package that creates these conditions is therefore vital.

We have some significant concerns over the finance package outlined in the Draft Determination (DD):

- The cost of debt allowances need to appropriately take account of borrowing costs, derivatives that hedge financial risk and infrequent issuance risk;
- The proposed cost of equity falls significantly short of the rates of return commensurate with the risks in the sector and the rate required to attract equity capital;
- Combined with our analysis of risk, the credit metrics implied by the DD mean that the notional company struggles to comply with the licence obligation to maintain an investment grade credit rating, even at P50 risk levels, suggesting the package is not financeable in the way that Ofgem suggests as there is insufficient headroom to manage even a small proportion of its risks.

Debt funding needs to cover borrowing costs appropriately at 41-45 bps higher than Ofgem's proposal

SGN accepts the approach of estimating efficient debt costs and using a trailing average, including an additional borrowing costs allowance, to cover average cost of debt at a sector level – provided this is calibrated correctly to capture all legitimate cost and risk positions appropriately.

However, we believe that a 0.17% additional borrowing cost proposed by Ofgem does not adequately cover borrowing costs, particularly costs associated with new issuance and index linked debt. We have also provided further evidence supporting a small company infrequent issuance allowance and set out proposals to deal with, on a case by case basis, derivatives that can be demonstrated to have been efficiently incurred to deliver a company's stated finance strategy.

In summary we believe:

- the trailing average needs to be calibrated to capture all legitimate cost and risk positions appropriately;
- the allowances for additional borrowing costs fall short of the amount required to cover networks' forecast costs - this needs to be at 42bps on notional debt;
- derivatives transacted and debt issuance costs incurred by SGN need to be recognised as part of efficient financing costs – 16bps on notional debt for Southern and 14bps on notional debt for Scotland;
- an allowance to cover for risk related to infrequent issuance needs to be recognised – the appropriate level is 6bps on notional debt for Scotland (26bps on forecast new issuance).

Putting all these items together justifies additional financing costs of 41 - 45 bps above Ofgem's proposal.

Appropriate cost of equity, that corrects for methodological errors and assumptions, will be higher than water.

Equity investors need a rate of return that is commensurate with the risk that they are exposed to by investing in the gas networks relative to equivalent sectors. Notwithstanding our views on the PR19 settlement, which is itself subject to redetermination by the CMA, as it stands in the draft determination, gas network investors will receive the lowest return of any regulated network in the UK. This is due to a number of methodological errors and assumptions that have not previously been adopted by regulators. In each instance the market evidence that supports the new approach is questionable and, coupled with the lack of regulatory precedent, increases the risk of it being wrong. These assumptions include;

- A perception that gas is not riskier than water – an assumption we challenge as it does not reflect the substantial risks of customer safety, and the risk of decarbonising heat;
- Moving to spot yields on government bonds to set the RFR;

- Using reconstructed and experimental historical CPIH estimates to restate the historical evidence on real TMR;
- Inappropriate use of averaging;
- Increases in debt beta;
- Adding European comparators to the asset beta calculation that are not good matches based on liquidity characteristics;
- Changing the methodology for some of the cross-checks and ignoring more relevant cross checks;
- Maintaining an outperformance wedge when as a company the DD presents us with an absolute shortfall.

When combined these changes have a significant impact of 259 bps compared to assessments put forward by the ENA on behalf of energy companies. Given the significant challenges facing the gas sector to deliver net zero, such a major change in finance assumptions needs to be supported by a substantial body of evidence given the impact that it will have on investor confidence if they are incorrect. The evidence presented so far falls well short of this high bar. Therefore, we believe that the cost of equity is significantly understated by Ofgem.

Each of these changes reduces the cost of equity and the attractiveness of the sector to such an extent that, when combined with the expected outperformance wedge, an investor in water will receive a higher return than the investor in a gas network that faces the 'existential issue'[500] of net zero. This does not appear to be a credible outcome and Ofgem's approach is wrong. Empirical assessment of the betas of companies positively benefitting from net zero trends suggests they have lower systematic risk compared to those companies more detrimentally exposed to net zero trends. Investors are now commanding a higher risk premium for investments in high carbon industries.

The notional company is no longer considered financeable.

We submitted a business plan that was assured by the board as being financeable for the actual and the notional company[501]. This was based on the working assumptions that were specified by Ofgem. Following our review of the DD, we do not consider the notional company is financeable.

It is instructive to review the changes to financeability through the primary credit metric of the Moody's Adjusted Interest Cover Ratio (AICR) used by Ofgem, and with a similar ratio used by Fitch (PMICR). The evolution of this metric is presented in the 'Adjusted Interest Cover Ratio for SGN' graph below. Taking the position at the end of GD1 (with 65% notional gearing), after adopting Ofgem's significantly lower cost of equity assumption, the notional company would likely have an AICR of 0.83. Without changes this would be below the threshold for investment grade. The DD improves financeability through a series of adjustments and assumptions to achieve ratios consistent with an investment grade credit rating in the current regulatory period.

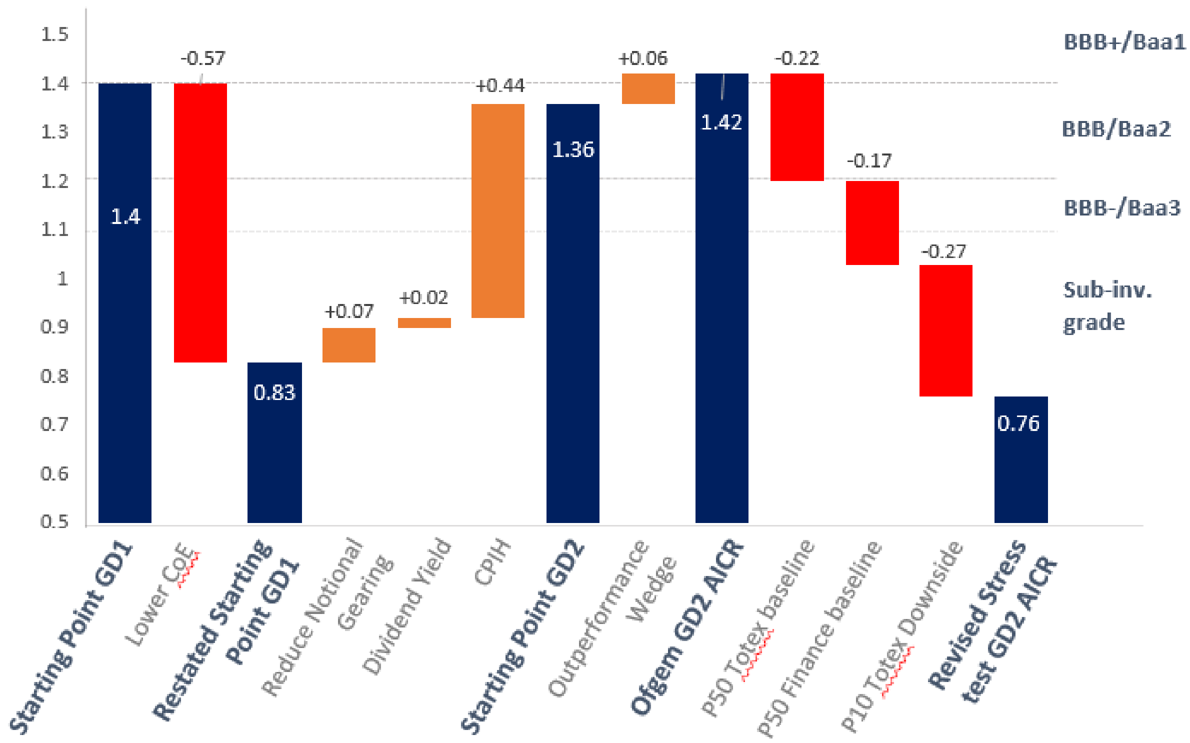
Firstly, Ofgem reduce the notional gearing assumption by requiring a 5% equity injection into the notional company which reduces notional debt interest costs; secondly, the GD2 dividend yield assumption is reduced to 3%, far below the level of the broader equity market, which defers equity distributions; and thirdly the immediate switch to CPIH indexation throughout the price control increases short-term cash returns in place of longer-term indexation to the RAV. Each of these actions improves the credit metrics in GD2 without improving the underlying risk of the companies. The resultant AICR metric of 1.36x requires careful interpretation as to credit quality which depends upon the sustainability of these regulatory decisions.

This produces a notional company credit metric of BBB / Baa2 which is clearly a significant weakening of credit quality from GD1 and relies on an assumption of outperformance to just pass into the BBB+/Baa1 range of 1.4x.

It is therefore Ofgem's inappropriate and unjustified DD finance assumptions that drive the notional company's assessed financeability rather than true measures of its financial resilience. We believe this undermines whether the test is meaningful and robustly tests whether the DD package is appropriately calibrated.

[500] As described by the Ofgem RIIO Challenge Group. RIIO-2 Challenge Group Report for Ofgem, Jan 2020, pg5
[501] SGN business plan, Dec 2019, Chapter 3.3

Adjusted Interest Cover Ratio for SGN (combined Scotland and southern)



As set out in this summary, the DD contains many areas where the risks are skewed to the downside through errors, omissions, excessively challenging targets and downside skewed incentives. The independent risk analysis conducted for SGN shows both lower expected returns and a more adverse stress test result. On an expected or P50 basis, the AICR ratio drops to 1.03x which is below investment grade levels, and under the combined P10 stress tests falls 0.76x. This clearly demonstrates that the DD package, despite substantial short term and flattering mitigations, does not provide adequate headroom to absorb even a fair balance of P50 risks. As Ofgem has already used reduced notional gearing, dividend yield and indexation to CPIH, there are no other levers able to restore the credit ratios to levels consistent with a strong credit rating. Any further mitigations in terms of accelerating cashflows do not address underlying issues as this is pushing the underlying credit quality problems into RIIO-GD3 and beyond and will not be acceptable to credit rating agencies. Recalibration of all areas of the package, as justified by evidence set out in this document, is the only remedy.

We believe a short-term focus on delivering unprecedented bill reductions creates intergenerational risk as assumptions made to deliver this do not deliver the sustainability and resilience our stakeholders request. We have shown in our business plan that meaningful bill reductions can be achieved by recalibrating the DD package without compromising the future.

To support the responses to the Finance Annex consultation questions, we have also included in the response the following independent consultant reports which the ENA have commissioned and submitted. These reports have informed our response to this consultation. These are as follows, with their abbreviation of how they are referenced in our responses in brackets;

- First Economics – 'RIIO-2 Prior Year Adjustments', September 2020 (First Economics Report 1)
- Frontier – 'Further Analysis of Ofgem's Proposal to Adjust Baseline Allowed returns', September 2020 (Frontier Report 1)
- Nera – 'Cost of Debt at RIIO-2', September 2020 (Nera Report 1)
- Nera – 'Review of Ofgem's DD Additional Costs of Borrowing, and Deflating Nominal iBoxx', September 2020 (Nera Report 2)
- Oxera – 'The Cost of Equity for RIIO-2, Q3 2020 Update', September 2020 (Oxera Report 1)
- Oxera - 'Estimating debt beta for regulated utilities', June 2020 (Oxera Report 2)
- Oxera - 'What explains the equity market valuations of listed water companies', May 2020 (Oxera Report 3)
- Oxera – 'Asset Risk Premium Relative to Debt Risk Premium', September 2020 (Oxera Report 4)

- PWC – 'The Balance of Risk in SGN's GD2 Draft Determination', September 2020 (PWC Report 1)

The following Oxera reports constitute annexes to reports are annexes to Oxera report 1 above;

- 'Review of RIIO-2 finance issues Rates of return used by investment managers', March 2019
- 'Assessment of political and regulatory risk', March 2019
- 'Estimating RPI-adjusted equity market returns', August 2019
- 'Review of RIIO-2 finance issues - The estimation of beta and gearing', March 2019
- 'Risk premium on assets relative to debt', March 2019
- 'Is aiming up on the WACC beneficial to customers', April 2020
- 'Response to the CMA on estimating RPI-adjusted equity market returns', April 2020
- 'Are sovereign yields the risk-free rate for the CAPM', May 2020

6.1 Introduction

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

This question is addressed in section 6.2 below.

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?

This question is addressed in section 6.2 below.

6.2 Cost of debt

The trailing average needs to be calibrated to capture legitimate costs and risk positions. Currently the cost of debt allowance is understated by between 41-45 bps.

We accept the approach taken by Ofgem in setting a trailing average using a utilities index and based on a sector average, however:

- the trailing average needs to be calibrated to capture all legitimate cost and risk positions appropriately;
- the allowances for additional borrowing costs fall short of the amount required to cover networks' forecast costs **- this needs to be at 42bps on notional debt;**
- derivatives transacted and debt issuance costs incurred by SGN need to be recognised as part of efficient financing costs **– 16bps on notional debt for Southern and 14bps on notional debt for Scotland**;
- an allowance to cover for risk related to infrequent issuance needs to be recognised – **the appropriate level is 6bps on notional debt for Scotland - the equivalent of 26bps on forecast new issuance**;

Overall, we believe, for the reasons above, that the cost of debt allowance (at 17bps) is in total between 41-45 bps understated - provided the trailing average is calibrated appropriately (per the above).

Cost of debt indexation

We believe that following an indexation approach will incentivise companies to manage debt issuance prudently and efficiently, with the incremental borrowing cost allowance to cover reasonable costs incurred with issuing debt and managing risk position in line with the notional company structure. We do, however, believe it is important to highlight that there is risk associated with the proposed position that Ofgem has outlined under the draft determination – related to the base index and the calibration of the trailing average.

Cost of Debt - Base index selection

Ofgem have selected the iBoxx Utilities index as the base index for calibrating the cost of debt allowance on the basis that this approach provides a more appropriate match for network debt costs whatever market conditions ensue [502], with the underlying rationale that the iBoxx A/BBB index over-compensates the sector, and does not appropriately match the rating of the notional company.

Whilst we agree that the current rating of the iBoxx Utilities index is a closer reflection of the notional company rating (BBB+), it is important to consider the structure of the indices and the risk that this move creates for companies as there is a significant divergence in the credit rating categorisation and a smaller pool of bonds in the iBoxx Utilities index. The below table illustrates a comparison[503];

Redacted

[redacted]

As the iBoxx Utilities index is only categorised as Investment Grade there is a risk that the indices could diverge from the notional company rating and provide a degree of over- or under-compensation for networks. Given the size of the index this could be driven by changes within some of the larger constituents. Looking at the historical average rating of this index we can see that this has moved dramatically over time – see graphs below.

Redacted

[redacted]

[502] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 15, para 2.13
[503] Nera Report 1
[504] Nera Report 1

Redacted

[redacted]

The ENA commissioned a review of the iBoxx Utilities Index by Nera[506] to understand the risks of switching from iBoxx A/BBB index. The review flagged some important points related to rating risk and tenor risk, including:

- Ofgem sets revenue allowance for a notional company, with ratios consistent with Baa1/BBB+ (at best), i.e. Ofgem has stated that the notional package will ensure outturn ratios to be “two notches above investment grade”;
- If Ofgem uses iBoxx A/BBB, then companies are funded for new cost of debt of A3/Baa1 (or A-/BBB+), i.e. half a notch under-funding (there’s already a problem with Ofgem’s approach to financeability);
- Using the iBoxx Utilities index compounds the problem: if rating of Utilities iBoxx strengthens over RIIO-2, then this exacerbates the mismatch between rating for the notional company and the (new) cost of debt allowance. For example, if iBoxx Utilities aligns with A rating, this makes new cost of debt allowance another 1.5 notches higher than expected at review (i.e. under-funding by 1.5 notches relative to A/BBB);
- Nera have quantified the impact on new cost of debt allowance where iBoxx Utilities aligns with iBoxx A, as it has historically – results in under-funding of 15 bps relative to Ofgem’s assumed performance;
- Risk of change to remaining tenor also greater for iBoxx Utilities than iBoxx A/BBB, given fewer constituent bonds and potential impact of a large single issuance.

Cost of Debt - Base index selection: Proposal

Whilst we do not believe that the existence of this risk must prevent a switch to the iBoxx Utilities index, we believe Ofgem should ensure that the cost of debt allowance provided by this index is kept under review for any material divergence – at which point consideration should be given for controlling the allowance for credit rating to align to the appropriate notional company level.

Type 6 – Broad agreement with position put forward in draft determination. In its current state, the use of the iBoxx Utilities index as the reference index for the cost of debt allowance does not represent a material issue, however there is a risk of divergence from the notional company rating level and this needs to be monitored and addressed if there is a material departure.

[505] Nera Report 1
[506] Nera Report 1

Cost of Debt - Calibration of the index trailing average period

We believe that a trailing average period that appropriately covers the sector's embedded debt and forecast cost of debt - based on forecast iBoxx plus additional borrowing costs (not remunerated by the index) - is appropriate, provided that it is based on a fair and balanced assessment of cost and risk in each of these areas.

Ofgem has selected a trailing average period of 10-14 years from the iBoxx Utilities Index – this is based on a number of assumptions[507]. Whilst we agree with the majority of the assumptions made, there are some important areas that we believe Ofgem has not taken the correct approach:

- **3rd party guaranteed debt:** In taking the yield at issuance for embedded debt instruments, Ofgem is reflecting the credit quality of the bonds at issuance. For SGN, in 2005 a number of bonds were issued with guarantees from higher rated entities (monoline insurance companies) and a fee paid to those entities for the rating uplift and resulting yield benefit (which continues to be paid over the life of the embedded debt). This fee is not included within the yield at issuance and therefore is overlooked by Ofgem's assessment. As it represents a real finance cost to SGN and has facilitated a lower yield (i.e. a more efficient cost including the yield and fees than could have otherwise been achieved) that customers have benefited from, this cost should be compensated for; and
- **Floating rate debt**: To assess the cost of floating rate debt Ofgem uses the current forward curves to estimate the debt cost. This approach does not compensate companies for the risk management position they established when selecting floating rate over fixed rate debt. In taking the latest forward LIBOR curves Ofgem is effectively passing the risk on to the consumer and although that benefits them now it could be reversed in future price controls. This approach is also inconsistent with the assessment that Ofgem has made in two areas:
    - To establish if floating rate instruments have been issued at market rates, Ofgem[508] uses asset swap margins to value the spreads and should therefore use swap rates from issuance to assess the yield; and
    - Where they state that "it is companies and their investors rather than customers that should bear the risk of a company's choice of its actual capital structure"[509].

Cost of Debt - Calibration of the index trailing average period: Proposal

Guarantee fees need to be added into the cost of debt calibration for the SGN entities the annual cost is: **£0.5m for Scotland; and £1.3m for Southern**.

To correctly assess floating rate debt, the yield at issuance should be used to assess the correct embedded debt cost/risk position. We estimate that the approach taken by Ofgem results in a per annum interest difference versus the yield at issuance approach of: **£3.1m for Scotland; and £1.4m for Southern**.

This is particularly important if Ofgem maintains the position of excluding derivatives that have been transacted to hedge interest rate and inflation risk. As an example;

> *Scotland has a £80m floating rate note that pays 3m Libor + 100bps. This instrument was issued in 2008 and matures in 2043. The yield at issuance was c6% whereas Ofgem's approach would assess the GD2 costs as c2%. Note on the day of issuance Scotland transacted a derivative to receive 3m Libor +100bps and pay fixed rate of 6.2875% (including transaction costs) for the tenor of this debt instrument – which broadly illustrates what the cost would have been if the instrument had been issued in fixed rate.*

Type 1 - Factual or computational errors. Ofgem's calculations of embedded debt costs, used to calibrate the trailing average period for the reference index, do not reflect all legitimate cost and risk positions appropriately.

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[507] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 23-24, para 2.57
[508] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 22, para 2.50
[509] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 115, para 6.30

Cost of debt - additional borrowing costs

In the draft determination Ofgem propose additional borrowing costs of 17bps that are not captured in the iBoxx indices, this includes transaction costs, liquidity costs and cost of carry. We are broadly aligned with Ofgem's proposal for transaction costs and liquidity costs, however, we believe that Ofgem's dismissal of new issuance premium and index-linked issuance costs overlooks genuine costs/risk that issuers are subject to.

In addition, Ofgem's assessment of the cost of carry does not fully capture the cost that networks are forecast to incur in maintaining license conditions and investment grade benchmarks.

We believe that 0.42% additional borrowing costs is appropriate for a sector approach:

Category	Required allowance (bps)	Allowance application	Adjusted allowance (bps)
Transaction costs	6	All debt	6
Liquidity costs	4	All debt	4
New issuance premium	12	New debt	3
Index-linked issuance costs	80	New index-linked debt to achieve 30% of debt	12
Cost of Carry	17	All debt	17
Total	**N/A**	**N/A**	**42**

Further consideration of bespoke mechanisms is required to cover two important additional areas:

- Acute refinancing risk exposure for infrequent issuers – smaller companies, such as Scotland, carry greater exposure to the notional company structure – an incremental allowance of **6bps for Scotland** is required;
- Costs associated with existing prudent and efficient hedging – some network companies have entered into interest rate, inflation and currency derivatives linked to directly hedging debt issuance that has an impact on weighted average costs of debt in GD2 – an incremental allowance of **16bps for Southern** and **14bps for Scotland** is required (provided that floating rate debt and guarantee costs are appropriately covered in the trailing average calibration).

Additional Borrowing Costs - New issuance premium (and 'Halo effect')

In our business plan submission, we proposed an allowance to cover new issuance premium on the basis that iBoxx yields, because they are secondary trading yields, do not include the premium that a company must pay (included within the coupon and issuance price) to incentivise investors to participate in the bond issuance. We proposed an allowance of 12bps based on analysis of historical transactions by one of our relationship banks. Our position was supported by analysis that Nera performed[510] on the iBoxx A/BBB index to illustrate that there was a negative 'Halo effect' of 13bps for new issuance versus the index, when tenor and rating has been appropriately controlled for.

In the draft determination, Ofgem has maintained the same position that it took at the Sector Specific Methodology Decision stage and has challenged the analysis provided by Nera on the iBoxx A/BBB index on the basis that, it was based on zero coupon curves[511] and the pricing on the bond[512]. This leads Ofgem to conclude that they believe the halo impacts

[510] Cost of Debt at RIIO-2, 13 March 2019 & 'Halo Effect and Additional Cost of Borrowing at RIIO-2' (NERA, September 2019)

[511] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 179, "it is inappropriate to use it to measure against corporate bond yields of the same maturity to determine credit spreads because the bonds issued by companies are not zero coupon bonds and therefore there is a duration mismatch which impacts comparison."

[512] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 179," "convention in the market is to price a corporate bond over the nearest benchmark gilt, not over the exact tenor interpolated curve"

suggested by Nera are inaccurate and that Ofgem's own analysis[513] suggests networks do not face a new issue premium compared to the Utilities 10yr+ index.

In response to this feedback, Nera have updated their analysis[514] to include both the iBoxx A/BBB index and the iBoxx Utilities index. Nera have also modified the spread calculations to duration match network bonds and the iBoxx.

The results of their analysis illustrates that there remains a negative halo on both indices (see the below table) – for the iBoxx Utilities index this has been quantified as 10bps with all energy network bonds included and 14bps with post-March 2020 issuance excluded (to take account of Covid-19 impact on market volatility).

Nera state that Ofgem's reference to market convention on bond pricing, i.e. pricing over the nearest benchmark gilt, is not the basis that is used by empirical studies to measure new issuance premium or halo, and they highlight that in efficient markets pricing would be adjusted to reflect mis-match in tenor of the bond to benchmark gilt.

Halo effect (bps)

Index	Ofgem	NERA[1]
iBoxx A/BBB	+11	-4 (-2)
iBoxx Utilities	+4	-14 (-10)

Notes: 1. Estimates in parentheses include five bonds issued during COVID-19 period (post- March 2020). However, given market volatility and the substantive variation in spreads relative to benchmark spread, we consider it reasonable to exclude these recent issues.

We would add to this point that it is not the convention within secondary markets to exclusively mark pricing of bonds over benchmark gilts – interpolated gilts and z-spreads are commonly referenced. The most appropriate treatment is to base the analysis of iBoxx and the network bonds on the same basis – and that is the approach that Nera have taken in calculating yields against interpolated gilts of the same tenor for both the index and network bonds.

Additional Borrowing Costs - New issuance premium (and 'Halo effect'): Proposal

On the basis of our own analysis and the analysis provided by Nera we believe that new issuance premium is not compensated for by the iBoxx indices and therefore we propose an allowance of: **12bps –** provided that Ofgem calibrates the cost of embedded debt appropriately this premium should only need to be applied to new debt issuance, in which case the appropriate level would be **3bps**.

Type 4 – New evidence presented. Our assessment of the halo effect and new issuance premiums has been updated to assess the position on the iBoxx Utilities index and to reflect Ofgem's challenge to methodology. The updated analysis continues to justify the position that there is evidence of a negative halo and an allowance is required to cover new issuance premiums incurred when issuing new debt.

Additional Borrowing Costs - Inflation-linked debt cost

In the draft determination, Ofgem dismiss any requirement for an allowance to cover the inflation cost/risk position that companies are subject to. This is on the bases that Ofgem does not believe that a move to CPIH linked RAV and returns necessitates a strategy of issuing CPIH-linked debt[515]; managing potential mismatches between revenue and debt cost bases that all corporates are exposed to and is generally absorbed by the equity buffer [516]; and theoretical reasons for spreads on inflation-linked debt are traditionally considered to be higher than nominal debt[517].

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[513] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 180 "suggests networks do not face a new issue premium compared to the Utilities 10yr+ index" and they "do not propose to add a new issue premium to the index as an additional cost of borrowing"

[514] Nera Report 2

[515] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 182; "does not believe that a move to CPIH linked RAV and returns necessitates a strategy of issuing CPIH-linked debt"

[516] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 183; "Managing potential mismatches between revenue and debt cost bases is something that the majority of corporates are exposed to and is generally absorbed by the equity buffer"

[517] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 182-183; "There are theoretical reasons why spreads on inflation-linked debt are traditionally considered to be higher than nominal debt: longer duration and less liquidity. However, one has to be careful not to overstate the secondary market liquidity of the nominal sterling corporate bond market. In addition, in the IL market with much of the issuance being done in privately placed format, the public data is thin and disputable."

We dispute the position that Ofgem is taking on the purported discretion that companies have for managing the composition of nominal and index-linked debt within their capital structures and also the basis of inflation-linked debt (RPI vs CPI vs CPIH) that they hold.

Although these decisions are within the control of company management (in terms of execution), the approach that Ofgem has taken to structuring the notional company - with 30% of the debt position in CPIH index-linked debt - effectively creates a material risk for companies if they do not follow this structure. The approach to financeability has been designed in such a way that there is little/no headroom for the notional company at BBB+/Baa1 credit metrics, i.e. there is no equity buffer available to compensate for assuming a risk position. As a result, if companies do not hedge their positions (or receive a buffer in the form of an allowance to cover the risk position) they risk a deterioration in overall returns and credit rating metrics.

		Ex-ante RPI-CPI wedge	+100bps increase in RPI-CPI wedge
Real allowed rate of return (CPIH)	*a*	2.63%	2.63%
Notional gearing	*b*	60%	60%
Proportion of ILD	*c*	30%	30%
Cost of ILD (CPIH)	*d*	1.74%	2.74%
Nominal cost of debt	*e*	3.80%	3.80%
AICR= *a / [b*(c*d+(1-c)*e)]*		**1.37**	**1.26**

Note: Calculated based on Ofgem DD ARoR for GD2 assuming Moody's recognises only CPI accretion for ILD in cash interest calc. Ofgem reports higher AICR values in the DD of 1.4-1.5 for GD2 (Table 34 Finance annex)

Nera have produced a report[518] for the ENA that analyses premiums associated with issuing index-linked debt and as part of that analysis they assess the risk of basis mismatch and as an example they illustrate the impact of a shift in the RPI-CPI wedge for companies that have not basis matched (i.e. continue to hold RPI-linked debt vs CPI-linked debt). This table illustrates the impact of a 100bps increase in the RPI-CPI wedge whilst holding all other variables consistent – the impact is a deterioration of 0.11x in the AICR credit metric.

In order to assess the level of incremental allowance required to achieve a capital structure that matches the notional company, we have focused on trying to understand the components of the premium that exists for issuing CPI index-linked debt over nominal debt (for both direct and indirect issuance); and have referenced the most relevant public transaction (Orsted in May 2019) and direct market pricing quotes to make a transparent assessment of the appropriate allowance (shown below):

Direct CPI issuance

Orsted A/S executed a dual tranche issuance across nominal and CPI index-linked debt in May 2019 and by swapping (at market levels) both transactions to be on comparable bases we are able to illustrate that the index-linked transaction prices at a material premium to the nominal transaction. The table below illustrates[519] that on a comparable nominal interest basis (the starting point for the cost of debt allowance trailing average) the CPI-linked transactions priced at a c82bps premium.

Issuance type	Tenor	Nominal Gilt Yield	Nominal Gilt Spread	Nominal Yield	Swap rate	6m£l Spread	Linker Gilt Yield (RPI)	Linker Gilt Spread (RPI)	RPI Yield	Linker Gilt Spread (CPI)	CPI Yield
Nominal	14yr	1.33%	128bps	2.61%	1.40%	121	-2.08%	86bps	-1.22%	170bps	-0.37%
CPI-Linked	15yr	1.44%	210bps	3.54%	1.39%	215	-2.00%	149bps	-0.51%	238bps	0.38%
Difference			**82bps**			**94bps**		**63bps**		**68bps**	

This transaction is particularly relevant for making this assessment as the two tranches were issued on the same day off the same documentation base/terms by the same issuer; they are of similar maturity at 14yr and 15yrs; and they are of a

518 Nera Report 2

519 Bank pricing and Bloomberg 9 May 2019 SWPM valuations

similar size at £300m and £250m (both benchmark size). The pricing is also based on primary market pricing, rather than secondary trading levels that can sometimes be affected by illiquidity.

We have separately shared with Ofgem the detailed calculations that back-up the numbers in the above table as well as the independent sources that we have used to corroborate the calculations.

There are limited transactions in the public domain that provide such a clear comparison (as the Orsted A/S transactions), however we have also taken a look at other utilities that have index-linked debt (RPI) and nominal debt outstanding that have similar maturities to determine whether there is a premium (see table below) for the former over the latter. In our approach we swap the index-linked bond real yield into nominal yields using Bloomberg's SWPM function and compare this to the fixed rate bond nominal yield. On each of these comparisons a premium is evident for the index-linked debt instrument versus the nominal debt instrument – similar or larger than that illustrated by the Orsted analysis.

Issuer	Issuance type	Maturity	Nominal Yield	RPI Yield	Difference in nominal yield (bps)
National Grid ET plc	Nominal	Mar 2035	1.64%	N/A	97
	RPI-Linked	Nov 2035	2.61%	-1.19%	
United Utilities Water Limited	Nominal	Feb 2035	1.34%	N/A	120
	RPI-Linked	Oct 2035	2.54%	-1.23%	
Heathrow Funding Limited	Nominal	May 2041	2.80%	N/A	167
	RPI-Linked	Mar 2040	4.47%	0.15%	
SGN	Nominal	May 2040	1.81%	N/A	86
	RPI-Linked	Nov 2039	2.66%	-1.17%	

Source: Bloomberg 20 August 2020

Indirect CPI issuance

We are conscious that in order to achieve CPI index-linked debt proportions commensurate with the levels indicated by the notional company (across the sector) it would be challenging to rely on direct CPI issuance alone, therefore we also consider a synthetic approach of issuing nominal debt and swapping into CPI using an inflation swap. Using this approach, we consider that there is no issuance premium associated with the debt instrument itself as it is initially on the same basis as the cost of debt allowance, however in order to swap into CPI we must consider the costs associated with transacting such an instrument – counterparty credit and execution charges. To get a fair reflection of the costs we have asked each of our relationship banks to price the credit and execution charges of a derivative where SGN receives nominal fixed rate and pays CPI inflation plus a real rate.

To be consistent with a direct debt issuance transaction and the trailing average endpoint we asked banks to base the pricing on 15yr maturity and no breaks in the transaction or inflation pay down. **The average pricing point for this transaction across 6 banks was 78bps.**

Additional Borrowing Costs - Inflation-linked debt cost: Proposal

As a reasonable estimate of an allowance to cover the cost of issuing CPI index linked debt, we propose a blend of the indicative premium/cost levels for direct and indirect CPI issuance. The average of the two is: **80bps –** provided that Ofgem calibrates the cost of embedded debt appropriately this premium should only need to be applied to new debt issuance in order to establish a 30% index-linked level of debt (consistent with the notional company), in which case the appropriate level would be **12bps**.

Type 4 – New evidence presented. To support the position presented in the draft determination, we have undertaken further analysis of index-linked debt issuance versus nominal debt issuance that shows a clear premium for issuing the former and a requirement for an appropriate allowance to match the debt profile of the notional company.

Additional Borrowing Costs – Cost of Carry

In the draft determination, Ofgem estimate the cost of carry to be within a range of 1.5bps to 11bps based on RFPR and group accounts data showing cash on balance sheet[520]. In making this calculation Ofgem applies[521] a 75% weighting to network company OpCo data and 25% weighting given to group company data and bases the cost on estimated differential between iBoxx and 3 months deposit rates.

They dismiss the estimate provided by Nera of 16bps to 45bps (broadly in line with our proposal in our business plan submission assuming systematic 20yr issuance) on the basis that they are concerned about double counting cost of carry and commitment fees[522]; Ofgem believe credit rating agencies would apply flexibility around the 12-24 months forward-looking liquidity requirements[523]; and they expect efficiency in the treasury teams to achieve a lower cost of carry[524]

We have revisited our assessment of this and understand Ofgem's concerns on double-counting of the allowance between the liquidity costs and cost of carry. However, the position Ofgem has taken continues to underestimate the costs associated with pre-financing debt maturities and investment activities in order to ensure that networks do not breach license obligations or investment grade requirements on liquidity from the credit rating agencies.

There are four main issues with Ofgem's approach, detailed below:

- Ofgem's analysis does not reflect divergent approaches taken by companies to location of Treasury functions and therefore cash balances. For SGN, prior to 2018 all of the cash pooling was undertaken at the parent company level and since 2018 the cash pooling has been moved to be at the operating company level. This makes the Ofgem approach unreliable as it underestimates the level of cash that was being held directly by Southern and Scotland or indirectly on their behalf;
- The historical assessment of cash balances conducted by Ofgem on RFPR and group accounts data underestimates the expected level of cash balances that will need to be held in GD2 – as the average (and median) is skewed down by the years in which no pre-funding was required (as there was no significant debt maturity).

  For example, across Southern and Scotland there was c£1.3bn of debt maturing that needed refinancing in GD1 (12 months ahead of maturity) - with only three years where the total amount is greater than GBP public benchmark size in any one year. In GD2 the equivalent amount is 50% higher (over a shorter price control) at c£2bn of debt that will need to be issued (12 months ahead of the maturities) – with all five years of the price control requiring a total amount of issuance greater than GBP public benchmark size (see graph below);
- Liquidity facilities are not sufficient in size to address all liquidity needs and in particular 100% of debt maturities. The combined liquidity facilities for Southern and Scotland, at £360m, are broadly 10% of the notional debt level that Ofgem has used in its calculations for the liquidity costs. The full £360m, however, is not fully available and allocated to covering upcoming debt maturities.

  A proportion of the facilities is expected to cover the monthly operational working capital requirements of the networks (which are negative given the timing of shipper receipts), forecast investment expenditure and uncertainty in working capital. Even if the facility was fully allocated to debt maturities, it would not be sufficient on its own to cover the size of some of the aggregate debt maturing in GD2 – see graph below, largest amount is c£630m in FY26. We therefore believe that cost of carry needs to be addressed in part by pre-funding but can in part be supported by liquidity facilities;
- Citing that treasury teams should be able to achieve investment returns greater than LIBOR suggests that Ofgem expects network treasury teams to be able to outperform the 'ask' side of a liquid market (note theoretically speaking

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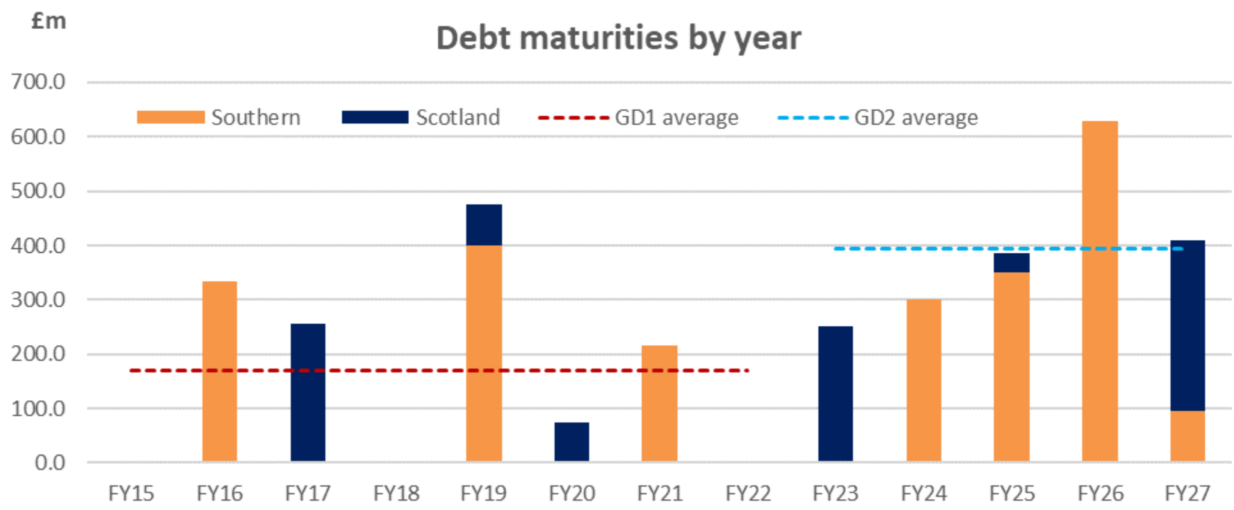
[520] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 17 & pg 182
[521] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 182
[522] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 182
[523] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 182 "take into account: Cash and equivalents; FFO if positive; Working capital movements if positive; Undrawn parts of the committed credit facilities; Other softer factors, such as: Standing in the debt markets;Well-established relationships with banks; Prudent risk management."
[524] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 182 "expect efficient treasury teams to achieve a cost of carry for any cash of less than the full differential between LIBOR and the cost of debt"

the calculation should be performed on the 'bid'). This would suggest that Ofgem expects treasury teams to take on additional risk in order to increase returns – which in our view is inappropriate for a regulated network to consider.



Source: Southern & Scotland RFPR data
Note the above assumes refinancing maturities at least 12 months in advance therefore GD1 issuance covers maturities in FY15 to FY22; and GD2 issuance covers maturities in FY23 to FY27.

Additional Borrowing Costs – Cost of Carry: Proposal

Taking into account Ofgem's concerns and our further analysis/evidence of the cost of carry risk/cost forecast in GD2 we propose calculating the cost of carry allowance based on weighting a proportion of the pre-funding requirement to be addressed by the liquidity facilities (50%) and a proportion by cash based debt issuance 12 months in advance (50%). **If we assess that based on forecast Southern and Scotland debt issuance in GD2 that would suggest an allowance of 17bps.**

Type 4 – New evidence presented. We have acknowledged Ofgem's feedback and amended our analysis to take account of reasonable challenge to our business plan position. Our updated assessment illustrates that the allowance proposed by Ofgem to cover cost of carry is not sufficient to cover the forecast costs that networks would expect to incur in GD2.

Further borrowing costs considerations – Infrequent Issuer Premium

In the draft determination, Ofgem provided a response to the proposed infrequent issuer allowance (or small company allowance) that we proposed for Scotland. Ofgem highlighted concerns with the approach taken and concluded that they didn't find evidence of consistent underperformance[525]; they consider swaptions pricing would be reflecting an asymmetric hedge[526] and that vanilla swaps should also have been considered[527].

Ofgem has not provided full details of how they conducted their assessment of cost of debt performance for networks, therefore it is difficult to provide a critique of their approach and provide feedback. However, we would note that in the case of Scotland, historical cost of debt performance against the iBoxx A/BBB 10yr+ index has been supported by the following factors:

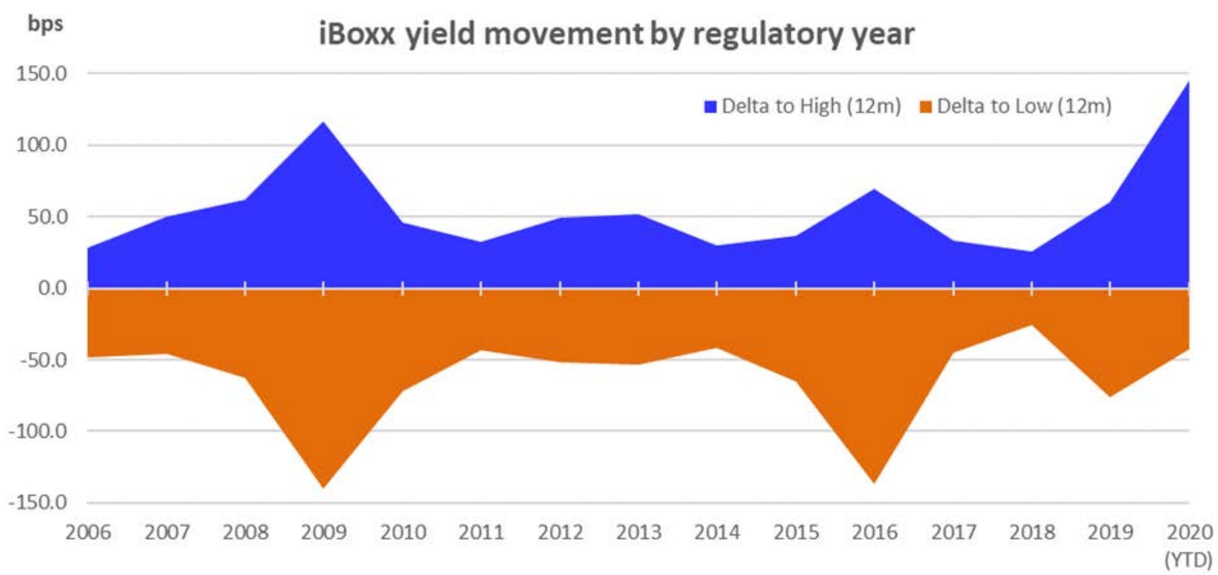
[525] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 19 "did not find any systemic consistent underperformance of smaller networks' issuance or of smaller networks overall consistently underperforming larger networks in terms of their overall cost of debt."
[526] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 19 "consider swaptions pricing would be reflecting an asymmetric hedge - it hedges the risk for the issuer against issuing at a worse rate than the long-run average but the issuer would keep the benefit of issuing at a better rate than the long-run average."
[527] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 19 "Using swaps rather than swaptions could offer a more symmetrical hedge but this potential hedging option does not appear to have been considered by SGN Scotland"

- Utilisation of monoline wraps/guarantees - to uplift issuance ratings beyond the rating of the issuer (at the time of issuance) for a fee (not factored into bond coupons/yields);
- Issuance of loans with the EIB – where the notional principal amounts available have been supportive of more frequent issuance, pricing levels have been very competitive and tenors executed shorter than typical in GBP public debt markets (and shorter than the weighted average life of the iBoxx);
- Issuance in US private placement (USPP) markets – where the notional principal amounts available have been supportive of more frequent issuance and pricing competitive vs GBP public markets.

Going forward, we do not consider that all these options are available, or that they provide a reasonable risk-free & reliable alternative, i.e.:

- Monoline wraps/guarantee - do not represent a clear net improvement (taking into account fees and coupon/yield improvement) for cost of debt that support mitigating the infrequent issuer risk;
- EIB loans – are no longer freely available following the decision by the UK government to exit the European Union;
- USPP – pricing within this market is not explicitly linked to GBP public markets and therefore is not a credible permanent alternative market for a smaller issuance. Pricing has at times been tighter than GBP public markets and Scotland has opportunistically taken advantage of this to issue at lower rates than iBoxx (which customers will benefit from in GD2), however the pricing in this market can be significantly wider than GBP public markets – for instance the most recent pricing update we have from our banks (11 August 2020) indicates that a 15yr maturity would price 80bps wider in USPP markets vs GBP public - and that represents an additional cost for Scotland.

In our business plan for Scotland we highlighted that based on taking the forecast RAV and notional gearing levels we would anticipate that Scotland will have a requirement to issue a benchmark sized GBP public issuance every 1,190 days (3.25yrs). This exposes Scotland to significant interest rate and credit spreads risk. The below graph shows an update of annual volatility in iBoxx rates (note less frequent issuance than annually would show even greater divergence between high, low and average) – recent volatility in markets is a timely reminder of how big this gap can be.



Source: IHS Markit iBoxx A/BBB 28 August 2020[528]

We considered a number of different approaches at that stage, including vanilla interest rate swaps; swaptions; and sub-benchmark sized public issuance, and we concluded that none of the approaches provides a perfect fit for hedging the

[528] Disclaimer for all IHS Markit data included within this report: "Neither IHS Markit, its Affiliates or any third part data provider makes any warranty, express or implied, as to the accuracy, completeness or timeliness of the data contained herewith nor as to the results to be obtained by recipients of the data. Neither Markit, its Affiliates nor any data provide shall in any way be liable to any recipient of the data for any inaccuracies, errors or omissions in the IHS Markit data, regardless of cause, or for any damages (whether direct or indirect) resulting therefrom. IHS Markit has no obligation to update, modify or amend the data or to otherwise notify a recipient thereof in the event that any matter stated herein changes or subsequently becomes inaccurate. Without limiting the foregoing, IHS Markit, its Affiliates, or any third party data provider shall have no liability whatsoever to you, whether in contract (including under indemnity), in tort (including negligence), under a warranty, under statute or otherwise, in respect of any loss or damage suffered by you as a result of or in connection with any opinions, recommendations, forecasts, judgments, or any other conclusions, or any course of action determined, by you or any third party, whether or not based on the content, information or materials contained herein."

risk. Our proposal was to put forward the approach that balanced the risk/allowance most evenly, 'in the round' – Swaptions were the most appropriate choice on the basis that the asymmetric pay-off on the interest rate exposure would offset frequency mis-match on the interest rate exposure and the lack of hedge for market credit spread exposure.

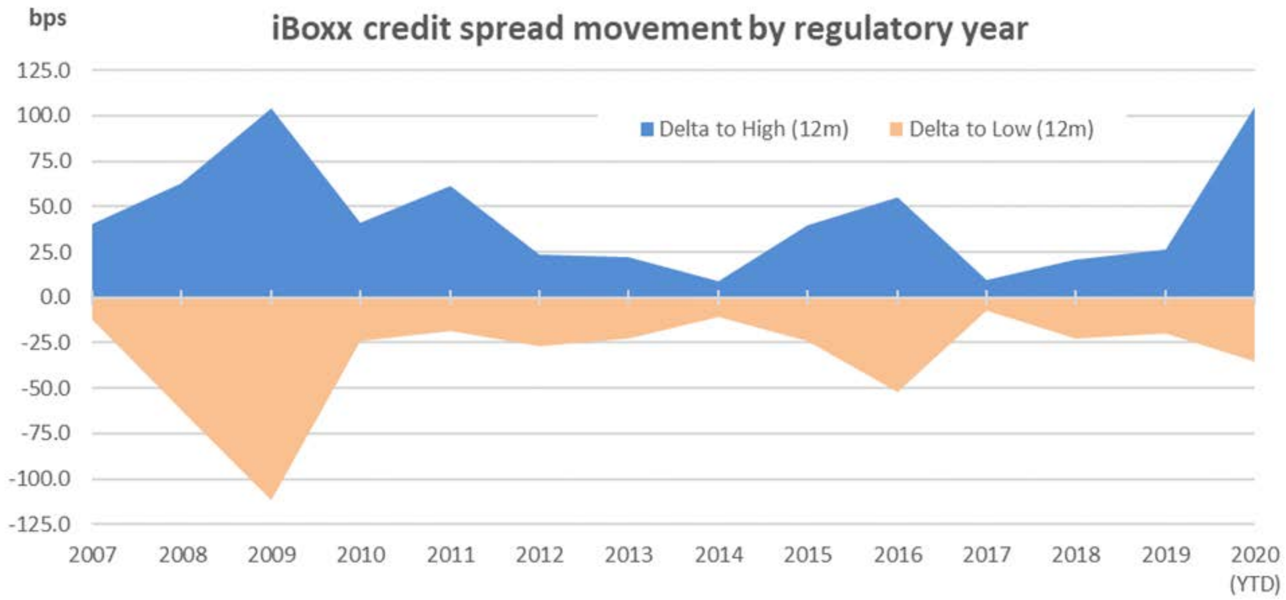
The below table illustrates, how we considered each option with a RAG-status compared to the notional company:

Approach	Interest rate risk hedge	Credit spread risk hedge	Indicative cost / premium	Pricing reliability	Comments
Vanilla interest rate swaps	Quarterly	No	24bps	Frequent transactions	Only covers interest rate risk; Mis-match hedge frequency.
Sub-benchmark issuance	Bi-annually	Bi- annually	Up to 25bps	Limited transactions	Assumes systematic £150m issuance; Market capacity issues; Frequency of transactions makes indicative pricing unreliable; Hedge frequency still unacceptable.
Swaptions	Quarterly	No	33bps	Regular transactions	Only covers interest rate risk; Mis-match hedge frequency; Asymmetric pay-off seeks to deal with imbalance.
Notional company allowance	**Daily**	**Daily**	**N/A**	**N/A**	**No possible/practical to implement; No premium/allowance offered.**
Constant maturity swap (CMS)	Daily	No	26bps	Limited transactions	Only covers interest rate risk.

Source: Bank pricing taken from relationship banks updates

Following the draft determination, we have reviewed availability of debt issuance hedging structures with our relationship banks and challenged them to come up with a more accurate valuation of the risk by considering a swap that hedges daily interest rates against a single debt issuance date. The most appropriate solution that we can provide is a CMS that effectively allows the issuer to swap out (i.e. receive) a fixed iBoxx rate (on the date of issuance) and pay a rate that is reset daily based on swap rates to match the duration of a debt issuance. For valuation purposes we have assumed a 15yr maturity. The indicative credit and execution charge is 26bps (based on the average of quoted from three of our banks). It is important to flag that this solution valuation does not completely cover the networks financial risk and two areas of exposure remain:

- CMSs are not a frequently transacted product however the pricing levels indicated are supported by the levels shown in the vanilla interest rate swap approach - a much more frequently traded instrument;
- Credit spread risk is not hedged – and therefore infrequent debt issuers still carry disproportionate financial risk exposure – see below illustration of the historic credit spread risk as indicated by the iBoxx index.



Source: IHS Markit iBoxx A/BBB 28 August 2020

Further borrowing costs considerations – Infrequent Issuer Premium: Proposal

As a reasonable estimate of an allowance to cover infrequent issuance risk for Scotland we propose using the CMS as a reasonable valuation of the interest rate risk (and the best estimate available) at **26bps** provided that Ofgem calibrates the cost of embedded debt appropriately this premium should only need to be applied to new debt issuance , in which case the appropriate level would be **6bps for Scotland.**

Type 4 – New evidence presented. We have acknowledged Ofgem's feedback to our business plan proposal and although we do not agree that our proposal would over-compensate for the infrequent issuer risk we have undertaken further analysis to support the valuation of this exposure and have modified the level accordingly.

Further borrowing costs considerations – Derivatives

In the draft determination, Ofgem propose to conduct the cost of debt calibration exercise excluding derivatives on the basis of the bespoke nature of derivatives[529], the difference in opinions of networks[530], derivatives can be used to shift costs from one period to another[531] and regulatory precedent[532].

We agree with Ofgem that derivatives might not always be used by companies for hedging purposes and that it is important that any calibration of the cost of debt allowance takes this into account. However, derivatives are an important financial risk management tool for regulated businesses in helping mitigate exposure across a number of areas, including:

- Foreign exchange currency risk on non-GBP debt issuance – networks and customers benefit from diversifying debt issuance across as many investors as possible. One avenue for diversifying debt issuance is to access foreign currency markets, however without the ability to transact cross-currency swaps this would leave networks inappropriately exposed for foreign exchange risk;
- Interest rate risk – as highlighted in other sections, the approach to cost of debt allowance under the notional company structure creates interest rate risk for actual companies as it is based on a daily averaging of an iBoxx index

[529] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 23, para 2.52 An exercise undertaken flagged "190 derivatives receive or pay legs as being more than 25bps from benchmarks" and Ofgem are concerned that "this exercise highlighted to [Ofgem] that given the bespoke nature of derivatives, it is difficult to make comparisons and assess if they have been incurred at market rates."

[530] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 23, para 2.53

[531] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 23, para 2.54 "derivatives can be used to shift financing costs form one period to another and that future derivative use is very difficult to predict"

[532] RIIO Draft Determination – Finance Annex, 9th July 2020, pg 23, para 2.56

(that is constructed of interest rates and credit spreads). It is not possible/practical for networks to closely hedge this exposure through daily debt issuance – in fact debt issuance, on average, is unlikely to be more frequent than annually for even the largest networks. Interest rate derivatives are an important tool for networks to be able to lock in interest rates on a more frequent basis and mitigate this risk to some degree; and

- Inflation risk – the notional company structure is based on a capital structure that contains 30% of debt in CPIH linked debt. In order to reach the same level of exposure, for hedging purposes, actual companies will need to either issue directly in CPIH linked debt markets or swap other debt issuance (nominal debt or inflation linked debt in other bases) into CPIH linked debt. Markets in CPIH linked debt are still embryonic and the use of inflation linked derivatives is an important tool for achieving the levels required to match the notional company structure.

The SGN networks have historically only transacted derivatives to hedge interest rate and currency exposures, detailed below:

- In August 2004, at company establishment, both Scotland and Southern were planning to issue long-term debt in the capital markets to create an efficient capital structure. Anticipating a material level of debt issuance, and resulting interest rate risk, both companies undertook interest rate swaps (in August 2005) to lock-in interest rates on a proportion of the forecast debt issuance. The interest rates achieved (pre-bank charges) were:
  - Southern 5.419% on £480m notional amount maturing in 2025; and
  - Scotland 5.419% on c£187m notional amount maturing in 2025.

  All of these were in line with market-based swap levels and therefore the interest rate swaps represented efficient transactions. In order to close out these interest rate hedges at debt issuance (October 2005), off-setting swaps were transacted – again at market interest rate levels – as interest rates at the time of the debt issuance had fallen this resulted in a negative mark to market on the transactions that is paid across the life of the transactions. The cost incurred represents the position that both Scotland and Southern would have been in if they had accessed debt issuance markets in August 2004; and
- In March 2008, Scotland issued an £80m floating rate note with a tenor of 35yrs. On the date of the debt issuance Scotland also transacted an interest rate swap to fully hedge the debt issuance into fixed rate. The interest rate achieved (pre bank charges) was 6.2875% in line with market-based swap levels and therefore represents the equivalent level of issuing a fixed rate debt instrument and should be considered an efficient transaction.

We believe that it is unfair for Ofgem to exclude the impact of derivatives that have been legitimately utilised for mitigating financial risk as part of their hedging activities and propose that Ofgem assess use of derivatives on a case by case basis.

Further borrowing costs considerations – Derivatives: Proposal

We have undertaken an assessment of the forecast net interest position in GD2 that we have under the derivative instruments in Southern (additional £4.5m per annum) and Scotland (additional £5.5m per annum) and propose that an incremental allowance to cover this cost of: **16bps (Southern)** and **14bps (Scotland)** based on the forecast average debt positions of each entity (calculated on notional company gearing).

Note that this allowance proposal is part linked to our position highlighted earlier in the cost of debt calibration – floating rate yield calculation on embedded debt. If yields at issuance are not treated appropriately, in line with our earlier proposal, there would be a need to cover the impact of the interest rate swap transacted by Scotland in 2008 - an incremental c36bps increasing the 14bps above to 50bps).

Type 4 – New evidence presented. To justify that an allowance should be provided to cover the impact of derivatives on interest costs, we have provided evidence on use of derivatives within Southern and Scotland to illustrate that their use has only been as part of legitimate and prudent risk management activities at pricing levels in line with efficient market pricing.

Deflating the Nominal Cost of Debt

As evidenced in section 5 of Nera report 2, SGN see the merits of Ofgem's proposed use of OBR's 5 year ahead forecasts to deflate the nominal iBoxx index in terms of the forecasts tending to be stable over time, and not having the issues that using Breakeven inflation has in terms of inflation risk and liquidity premiums. However, we also recognise that adopting the outturn inflation used to index the RAB would ensure that investors recover nominal debt costs through allowed cost of debt and RAV indexation, and using a trailing average would enable this deflationary measure to be stable as well.

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?

We don't believe that we have got all the information to provide an informed answer. However, if Ofgem do deem it appropriate for SHET to have a bespoke RAV weighted allowance calculation then it would also be appropriate for Ofgem to consider other bespoke mechanisms for small company premiums and efficiently issued derivatives, as set out in our response to FQ1.

6.3 Allowed return on equity

Equity investors need a rate of return that is commensurate with the risk they are exposed to by investing in the gas networks relative to equivalent sectors. As it stands in the draft determination, they receive the lowest return of any regulated network in the UK, and this is due to the number of methodological errors and assumptions that have not previously been adopted by Regulators. In each instance the market evidence that supports the new approach is questionable and this, coupled with the lack of regulatory precedent, increases the risk of it being an invalid assumption. These assumptions include;

- A perception that gas is not riskier than Water – an assumption we challenge as it does not reflect the substantial risks of customer safety and in decarbonising heat
- The significant increases in risk in the DD package is not reflected in the equity beta
- Moving to spot yields on government bonds to set the RFR.
- Using reconstructed and experimental historical CPIH estimates to restate the historical evidence on real TMR.
- Inappropriate use of averaging of the historical TMR.
- Increasing the debt beta which we believe is not appropriate
- Adding European comparators to the asset beta calculation that are not good matches based on liquidity characteristics.
- Changing the methodology for some of the cross-checks and ignoring more relevant cross checks.

Combined these changes have a significant impact of 259 bps compared to assessments put forward by the ENA on behalf of energy companies. Given the significant challenges facing the energy sector to deliver net zero, such a major change needs to be supported by a substantial body of evidence given the impact that it will have on investor confidence if it is incorrect. The evidence presented so far falls well short of this high bar and materially understates the appropriate cost of equity.

Each of these changes reduces the cost of equity and the attractiveness of the sector to such an extent that when combined with the expected outperformance wedge (which we fundamentally disagree with) an investor in water will receive a higher return than the investor in a gas network that faces the 'existential issue'[533] of net zero, an outcome that does not appear credible.

6.3.1 Risk free rate and equity indexation

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?

We recognise Ofgem is minded to index the cost of equity, and on this basis we agree the best approach is to index the risk free rate only, assuming the weight of evidence is placed on a correctly deflated and averaged long term stable

[533] As described by the Ofgem RIIO Challenge Group. RIIO-2 Challenge Group Report for Ofgem, Jan 2020, pg5

TMR. However, we believe that government bond yields are an underestimate of the Risk Free rate (RFR) as set out below;

As detailed in section 2.1 of Oxera Report 1, the CAPM defines the RFR as the rate of return on a zero-asset beta and assumes that investors and firms borrow and lend at the RFR. That assumption does not hold when considering Ofgem's estimate of -1.5% (CPIH-real) which is based on spot yields on government bonds. Historically Ofgem estimated the RFR by adding a spread above spot government yields. Prior to 2019, the regulatory allowance for the risk-free rate was set above the spot yields on government bonds, implicitly converting the government bond yields into a useable RfR; they no longer add such a wedge. Therefore, the regulatory issue of an underestimated risk-free rate in the CAPM framework was less severe. The average gap was 149bp over 10Y ILGs and 131bp over 20Y ILGs. However, in the most recent DDs, the regulatory allowance for the risk-free rate was reduced to the same level as the spot yields on government bonds.

Type 1 - Factual or computational errors. Investors and firms can't borrow and lend at the spot RFR.

Section 2.1 of Oxera Report 1 details that government bond yields are an underestimate of the RFR to use in the CAPM due to two reasons;

- A substantial convenience premium for government bonds: Empirical studies show that government bonds possess special safety and liquidity characteristics compared to other securities. This pushes the yields on government bonds below the required rate of return for a zero-beta asset. Therefore, to be used as a proxy for the risk-free rate, the yields on bonds issued by governments with a high sovereign credit rating would need to be adjusted upwards to remove the impact of the convenience premium.
- The gap between corporate and sovereign risk-free financing rates. The CAPM assumes that all investors can borrow and lend at the same risk-free rate. However, in reality, non-sovereign investors with even the highest creditworthiness face higher borrowing rates than those faced by governments.

Oxera set out in section 2.1 how there is a positive spread between the yields of the 'highest quality corporate bonds' (AAA rating, with AA as a cross check) that non-sovereign investors with the highest credit worthiness can access, and government bonds. This differential has averaged at 70-80bps in the last 6 months, suggesting the RFR would be underestimated if it was set equal to spot or forward yields on government bonds.

As set out in their report, in order to provide a more informed view of the allowed RFR during RIIO-2, Oxera believe an uplift should be applied based on the difference between current spot rates and average forward rates for RIIO-2.

An RFR range of -1.15% to -1.0% (CPIH real) is thus proposed based on a spot iBoxx £ corp AAA 15+ of -1.16% (CPIH, real), minus a downward adjustment for the default risk premium of -10bps, with a forward premium of 0.11%-0.26% following Ofgem's DD uplift calculation.

Oxera detail further how a cross check of adding a premium to UK gilts generates a RFR forecast of -0.9%. They conclude their preferred method to determine a rate that investors and firms can borrow/lend at uses the default-adjusted AAA rate, given the issues they note with government bond yields. However, their cross-check using a traditional 'bottom-up' approach also generates similar estimates of RfR. Therefore they believe, based on market evidence as of 31st July, that -1.0% is an appropriate assumption for the RFR, but note that once the value of the RfR is fixed at the start of RIIO-2 it can be subsequently be indexed for changes in government bond yields on an annual basis throughout RIIO-2.

The use of a one month averaging period (October in prior year) proposed by Ofgem would be representative of only 5 months out of a 5-year regulatory period. Risk-free rate allowances estimated over short periods bear significant risk of not representing the spot RFR over RIIO-2, which defeats the aim of introducing indexation of the RFR for RIIO-2 and overreacts to interest rate changes.

Type 1 - Factual or computational errors. Using October RFRs would only represent five months out of a five year regulatory period

On the other hand, using a 12 month average would provide a more stable estimate of the RFR for the forthcoming year (e.g. using Nov-Oct period prior to the regulatory year as evidenced by Nera in their report on cost of equity indexation[534]). In addition, European regulatory precedents support the use of an averaging period of at least six months as set out on p11 of the same report.

[534] Nera (2019) 'Cost of Equity Indexation using RFR', p18

Type 4 – New evidence presented on why October RFRs are not representative

6.3.2 Total market returns

Ofgem errors in estimating the Total Market Returns (TMR) that result in the cost of equity being materially too low:

- **Ofgem's relies on the adoption of an alternative Consumer Price Index (CPI) inflation series which the Office for National Statistics (ONS) considers to be unreliable and is consequently developing a new set of modelled indices;**
- **Ofgem has failed to recognise that investors will use a discount rate at least as high as the historical arithmetic average when taking capital budgeting decisions;**
- **Ofgem's decision contradicts evidence from dividend discount models that suggests the expected TMR has not decreased.**

Deflating Historic Total Market Returns

The use of long-term historical evidence requires reliable inflation data, as nominal returns need to be deflated into CPI real terms for use in the CAPM for the RIIO-2 cost of equity. Since the 2019 edition of DMS, the book has deflated the historic nominal returns with an inflation series that is a hybrid of RPI and CPI inflation. The hybrid inflation series creates problems when using long-term market data, which have been noted by the ONS. Therefore, real returns can't be used directly from DMS.

For comparability of long-term market data, one therefore has to deflate the nominal returns by a consistent inflation series. Oxera[535] have set out two possible methods for doing so:

- Adding the forecast RPI–CPIH wedge to RPI-real historical returns restated using today's RPI methodology, and
- Deflating nominal returns by CPI inflation, adjusted for bias in the historical estimates of CPI

The first option is Oxera preferred approach. The second approach is subject to a much higher degree of uncertainty because for periods prior to 1997 the CPI series has been estimated ex post. We consider it is more robust to start with the official RPI historical series and then to consider any adjustments to the RPI series

Type 4 – New evidence presented on the recommended approach for deflating historical TMR

Ofgem instead uses unadjusted estimates of historical CPI from the ONS. Oxera points out that this is mistaken[536]:

> *We note that Ofgem/UKRN perform neither of these adjustments, incorrectly using an unadjusted CPI measure. They instead note that '[the proposed adjustments] hinge on there being a consistent and perfect single measure of inflation for more than 100 years. The absence of this does not invalidate using the best available measure for each period of history, as implied by NG.' We disagree. A regulator should not intentionally use an unreliable and inconsistent inflation measure. To the contrary, our goal is to generate a comparable, consistent inflation measure across the entire time series, otherwise any calculation of a historical real TMR will be inconsistent with the way that inflation is measured today.'*

Further concerns with using the unadjusted estimates of historical CPI, as detailed in the Oxera report are;

- The ONS has been unable to locate the information used to construct the historical CPI estimate and has been unable to replicate them. The ONS is also currently revising the backcast of historical CPI. We consider that it would be inappropriate to switch to 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 CPI estimates are likely to be materially upward-biased estimates of inflation and, therefore, downward-biased estimates of real return;

[535] Oxera report 1, section 2.2.1
[536]Oxera report 1, section 2.2.1

- the consumption expenditure deflator (CED) inflation is likely to include the same degree of upward formula of that effect bias in the historical RPI series. Oxera have discussed this hypothesis with the ONS and they agree with this interpretation.
- Analysis undertaken by National Grid[537], shows that since 1956 the average differential between RPI and the CED is relatively stable at around 20bp. In comparison, the average differential between the CED and the backcast of CPI has changed significantly over time. This suggests that, prior to 1950, where the CPI backcast is using CED, this is both theoretically and empirically closer to RPI than CPI.

Type 1 - Factual or computational errors relating to Ofgem's use of the ONS historical CPI estimate

Averaging Historic Total Market Returns

As detailed in Oxera Annex report 1, section 2.2.1, an unbiased estimate of the market discount rate (i.e. TMR) will be closer to the arithmetic average than the geometric average. The Cooper (1996) estimator is the appropriate methodology to generate a TMR estimate for use in the CAPM, for the purposes of discounting, valuation, and setting the regulated rate of return. Ofgem's methodology incorrectly combines portfolio investment (compounding) with capital budgeting and valuation (discounting).

As evidenced in the Oxera report, the uncertainty about the true rate of return means that the arithmetic average has to be adjusted down to achieve an unbiased estimate of the future rate of return on an investment in a portfolio of securities, while the arithmetic average has to be adjusted up to achieve an unbiased estimate of the discounted value of future cash flows. The Ofgem approach embeds an assumption that the TMR is lower than the arithmetic average, which will contribute to the allowed return being lower than the discount rate being applied by investors to value the regulated companies and to make decisions about capital budgeting and investment appraisal.

Type 4 – New evidence presented on the recommended approach for averaging historical TMR

Conclusion on historical evidence

As evidenced in their report, Oxera[538] maintain their recommendation of deflating historical nominal returns by the adjusted RPI inflation series.

The arithmetic average of the RPI-real estimate should then be converted to an unbiased estimate of the discount rate using the Cooper (1996) methodology. Finally, the RPI–CPIH wedge of 81bp should be added to the resulting figures in order to obtain an unbiased estimate of the CPIH-real market discount rate. Oxera show that following this method leads to a range of TMR range of 7.29–7.94% (CPIH real).

Cross checks of the TMR

In sections 2.2.2-2.2.5 of Oxera report 1, Oxera evidence how the TMR is more stable over time and thus how the updated historical data detailed above supports a TMR range of 7-7.5% CPIH real. This is supported by evidence from Oxera's primary cross-check, the Dividend Discount Model (DDM), being volatile but pointing towards a higher TMR estimate than the range based on historical equity market returns of 7.29–7.94% detailed above.

As detailed in section 2.2.2, Oxera have constructed a DDM using the Bank of England's methodology. The Bank of England model links the long-term dividend growth rate to forecasts of the long-term growth rates of gross domestic product (GDP) for a weighted sample of countries. This is because the UK-listed companies in the index used in the DDM operate internationally and derive a significant proportion of their revenues from outside the UK. As such, the growth and risk of their dividends will be affected by international economic developments and not only by the UK economy. This risk will be reflected in the equity betas obtained by regressing company equity returns against the FTSE All-Share Index, and therefore consistency requires that these growth forecasts are used to infer the equity market discount rate from the DDM.

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[537] Oxera report 1, Figure 2.3
[538] Oxera report 1, section 2.2.1

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, Oxera consider it to be incorrect to use UK GDP growth forecasts in a DDM analysis of the FTSE All-Share, as it is unreasonable to assume that earnings growth outside of the UK will be on average the same as the GDP growth of the UK.

Type 4 – New evidence presented on the DDM cross check

Regulatory precedents were also considered in section 2.2.4 of the Oxera report 1, with recent regulatory announcements by Ofcom and Ofwat showing similar levels to Ofgem's DD TMR, but while recent publications have used a TMR below the historically observed level, Oxera considers these cannot be relied on for determining the TMR assumption for RIIO-2 because;

- in contrast to Ofgem, Ofcom does not have a financing duty. This allows Ofcom to attribute less weight to financeability constraints, thus allowing, all else being equal, a lower cost of equity to be assumed
- four water companies have appealed to the CMA, with the allowed equity return being a common ground of appeal across all appellants
- Finally, in the NATS appeal, the CMA has not taken into consideration the responses to its provisional findings. Hence, the TMR evidence could be revised once the merits of the points raised by the respondents are addressed
- The recent UK regulatory announcements also rely heavily on a number of recommendations made in the UKRN study. The similarity of approach and assumptions across different regulators means that these cannot be regarded as independent data points, which undermines their value as cross-checks.

6.3.3 Debt Beta

SGN does not believe that the DD assumption of a debt beta of 0.125 is correct and by relying on appropriate models and methodologies justified in this response, a debt beta of 0.05 is proposed.

As set out in the UKRN report authored by CEPA539 there are four methods for estimating debt beta;

- Direct method
- Indirect method
- Structural methods
- Decomposition methods

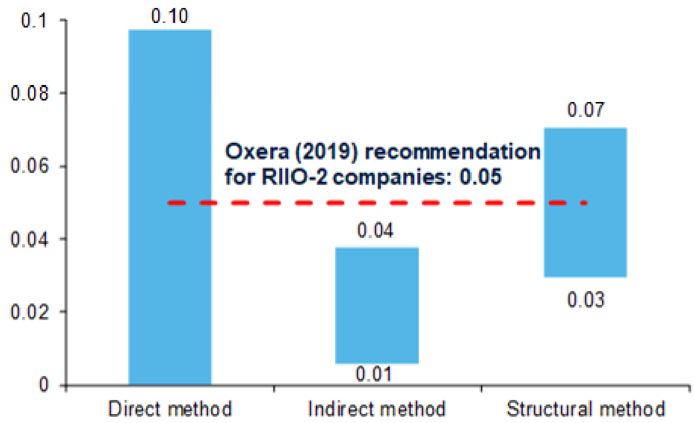
Section 3.2.2 of Oxera report 1 and Oxera Report 2 reach the following conclusions on these approaches;

- Methods based on regressions (the direct and indirect methods) and structural methods have the advantage of measuring the systematic exposure of debt to market risk. In contrast, the spread decomposition method lacks robust and theoretical support and depends on multiple uncertain parameters. The degrees of uncertainty suggests that it provides little or no incremental evidential value relative to the other approaches. Therefore, regulators should rely on regression based and structural methods when setting debt beta for a price control.
- Methods based on regressions must follow best econometric practice in terms of data inspection and cleaning model specification, diagnostic testing and interpretation of results. This is particularly important when working with bond return data, which presents additional challenges compared to equity return data (e.g. heterogenous securities and infrequent trading).
- Controlling for interest risk is important when estimating debt beta using a regression based method. Otherwise, the resulting debt beta estimate will capture risks over and above credit risk, resulting in a biased estimate. This was not reflected by CEPA when they compared the methodology used by Schaefer and Strebulaev (2008) i.e. the indirect regression based approach to the direct regression based methodology used by PwC and European Economics

[539] CEPA (2019), 'Considerations for UK regulators setting the value of debt beta', report for the UK Regulators Network,

- Therefore, regulators should rely on direct and indirect regressions and structural models. Using these methodologies, taking account of the corrected version of CEPA's structural method, a debt beta of 0.05 for regulated industries would be appropriate as shown the following chart from Oxera Report 1 (Figure 3.1);

Figure 3.1 Evidence on debt beta



Type 4 – New evidence presented supporting use of regression based (direct and indirect) and structural methods and methodological points on these

As detailed in section 3.2.2 of Oxera Report 1, it should also be noted that CEPA's UKRN report on debt beta cites (via a Nera report) empirical evidence in Fama and French (1993) as support for a debt beta as high as 0.22.[540, 541] However, Fama and French make no such claim. The test referred to in the CEPA report was an example showing how one can estimate erroneously high debt betas if one omits important factors. Fama and French actually conclude that the debt beta is negative or zero for all but the lowest-grade bonds. Our upper bound of 0.05 is therefore conservative based on academic evidence introduced as supporting evidence by CEPA. Oxera state[542];

> *'the incorrectly cited Fama and French evidence is the clear outlier in Table 4.2 of the aforementioned NERA report, where they also cite support for debt betas of 0.05 for AAA to A- bonds by the Brattle Group, and 0.04 for Schaefer and Strebulaev (2008). In contrast, Ofgem cites studies that selectively choose data points from NERA's report supporting a much higher debt beta, some of which appears to be based on a misrepresentation of the academic evidence as discussed above.'*

Ofgem[543] highlight that CEPA's report demonstrates that for each 5% increase in gearing the debt beta will increase by 0.03. Oxera[544] agree there is a theoretical relationship between debt beta and gearing, depending on theoretical assumptions, but show how no weight should be put on CEPA's and Ofgem's evidence on the relationship between debt and beta.

Finally, as detailed further in section 3.2.2 of Oxera Report 1, Ofgem has quoted Oxera in support of its 0.125 debt beta assumption in para 3.39 of the DD Finance Annex. However Oxera state, on p32 of their report, that the;

> *'0.2 statistically significant debt beta for National Grid is the result of the direct method, which is, if not specified correctly, subject to omitted variable biases and high standard errors.'*

Type 1 - Factual or computational errors. regulators should rely on regression based (direct and indirect) and structural methods when setting debt beta for a price control.

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540 Fama, Eugene F., and Kenneth R. French. 'Common risk factors in the returns on stocks and bonds.' *Journal of Financial Economics*, **33**:1, 1993, pp. 3–56.
541 CEPA (2019), 'Consideration for UK regulators setting the value of debt beta', report for UK Regulators Networks, 2 December https://www.ukrn.org.uk/wp-content/uploads/2019/12/CEPAReport_UKRN_DebtBeta_Final.pdf.
542 Oxera report 1, section 3.2.2
543 RIIO Draft Determination – Finance Annex, 9th July 2020 para 3.37
544 Oxera report 1, section 3.2.2

6.3.4 Aiming Up

SGN believe that Ofgem should aim up when setting an allowed return within the identified reasonable range for the cost of capital. As set out in Frontier's 2019 report on aiming up and the use of the outperformance wedge[545], this conclusion is based on a review of the relevant academic literature (in particular the model presented in Dobbs (2011)) and regulatory precedent.

The key arguments of this report as summarised in section 2.1 of Frontier report 1, are;

- Aiming up is an optimal regulatory response to the uncertainty inherent in estimating the cost of equity and the asymmetry of the consequences arising from setting the allowed return too high or too low, owing to the fact that it maximises societal welfare.
- Aiming up is common practice in UK regulatory regimes.
- The CMA in particular has, until very recently, consistently and transparently aimed up in its decisions.
- The relevant academic literature is supportive of aiming up.
- MPW's model supports aiming up for new investments, whilst its conclusion that there should be a lower rate of return for sunk investments rests upon an unrealistic level of myopia by investors to generate its conclusion and therefore should be disregarded.

Type 3 - Disagreement as to how the methodology should be applied

Ofgem made a number of points in response to these arguments in the SSMD and DD Finance Annexes – each of which is countered below, with further details in section 2.3.1 and 2.3.2 of Frontier report 1, respectively;

Symmetric Range for the WACC

We agree that the WACC parameters should be estimated symmetrically. The nuance is that due to there being an asymmetric risk of the midpoint of this range being too high or too low means there is a need for explicit aiming up in the final stage of determining a point estimate, with the exact location depending on the nature of the asymmetric risks. Indeed, there is evidence to suggest that, if anything, Ofgem may have aimed down on certain parameters, for example in its estimate of TMR and in respect of beta.

Cost of over- and under-remuneration

Ofgem appear to imply that the principle of aiming up is to deliberately over remunerate. Due to the high level of uncertainty on, in particular, the cost of equity, there is no guarantee that the midpoint of a best-endeavours and reasonably judged range would turn out to be precisely at or above the right level to satisfy this constraint. In this environment, given the asymmetric consequences of failure to invest, aiming up is an optimal regulatory response to the uncertainty inherent in estimating the cost of equity and the asymmetry of the consequences arising from setting the allowed return too high or too low. If the cost of capital is set too high, customers pay more for their bills. However, if the cost of capital is set too low there could be underinvestment in the sector. Given that most regulated services are essential goods, the welfare lost resulting from underinvestment is very high. The purpose of aiming up, as is made explicitly clear in the Dobbs model, is to maximise societal welfare (an objective that we do not consider controversial), not to systematically over-remunerate the company.

We agree with Ofgem that the cost of underinvestment and over renumeration need to be assessed separately. The costs of under investment that may directly harm customers include the following;

- Under investment may lead to a worsening in the operational performance of assets, leading to lower levels of reliability and more interruptions, to the direct detriment of customers.
- Under investment may also stifle innovation. This might lead to a failure to enhance existing service levels, to provide new services, to fully adopt the benefits of digitalisation and to deliver efficiency savings at the same pace and so forth
- Lack of investment may also harm the adoption and roll out of low carbon technologies at scale. For example, this may harm the ability of networks to accommodate inputs of unconventional gas, including hydrogen or gas/hydrogen blends.

[545] Frontier (2019) 'Adjusting Baseline returns For Anticipated Outperformance'

In order to illustrate the points above, in section 2.3.1 of Frontier report 1, Frontier provide an analysis comparing the benefit of under renumeration, though a cost of equity below the midpoint of the range, vs the societal cost of underinvestment in networks

Aiming-up and capacity shortage

We disagree with Ofgem's argument that because aiming-up would only be applicable for sectors with capacity constraints or significant growth it would not be necessary in the energy sector. As detailed further in section 2.3.1 of Frontier report 1, this is because;

- as long as there is significant need for investment in the sector, even if this is for routine asset maintenance and incremental enhancement, the argument for aiming up applies
- we consider that in fact there is likely to be significant growth in network capacity/capability needed in the GB energy sector over the years ahead. For example, gas networks may need to invest to meet new demands placed on the network and to potentially cater for alternative inputs of unconventional gas (including hydrogen).

Cross checks and double count

We also disagree with Ofgem's assertion that aiming up may lead to a double count owing to its use of cross checks on CAPM. This is mainly because there is significant uncertainty in the quality of the cross checks used by Ofgem, as set out in our response to FQ8

Political and legitimacy risk

We agree with Ofgem's point, that consistent over-remuneration may jeopardise the legitimacy of the regime, to the detriment of the customers as well as the companies. However, we consider that this would only be the case where there are entirely unjustified returns being earned, whereas the Dobbs model makes clear that aiming up is in fact entirely rational and justified.

Furthermore, we continue to believe that the legitimacy of the sector rests firmly on the ability of the regulator to calibrate well its price controls, striking a balance between ensuring the essential investment needed in the sector and the ongoing incentives for companies to drive efficiency gains and deliver value and quality service for customers. We do not believe unjustified blanket deductions from the cost of equity is the most effective way to ensure legitimacy.

The relationship between aiming up and the quantum of investment

As detailed in section 2.3.2 of Frontier report 1, Ofgem believe the choice a company has about whether to invest more or invest less is based solely on trading off the benefits to it that would arise from:

- rewards from the totex incentive mechanism should it not invest and hence underspend;
- against the benefit that Ofgem considers the company would receive through aiming up if it did invest.

Following this logic, a decision to aim up simply creates an unnecessary extra wedge of return, that the company would trade off against other sources of additional profit. Ofgem's conclusion is that it would take many years for the benefit from aiming up to pay off, and therefore doubts the effectiveness of the aiming up policy in bringing forward any extra investment.

Under Ofgem's logic companies have no incentive to invest at all. On the contrary, companies will always be better off not investing and saving money. However, this would clearly be an infeasible strategy for a company to adopt.

However, Ofgem's argument is concerning as it serves to illustrate that it continues to misunderstand the principle of aiming up. The intention is not to offer a wedge over and above the true underlying cost of equity to shift incentives to invest more. It is to avoid inadvertently setting the cost of capital too low, given the asymmetric risks associated with failure to invest. The logic is simple then – set the number (by accident) too low and investment will most likely not be viable and will not proceed.

CMA's Position on Aiming Up in the recent NERL Re-determination

As set out in section 2.3.2 of Frontier report 1, CMA has considered the question of aiming up in the NERL redetermination. It looked into the following 3 factors that it considered as possible reasons to depart from the midpoint of the range;

- potential bias in the cost of capital range;
- potential asymmetries in the broader price control settlement; and

- potential asymmetries in the balance of risk between getting the cost of capital too high or too low.

For the first factor, the CMA concluded its cost of capital range did not suffer from bias. For the second, the CMA acknowledged some asymmetries in some of the incentives in the price control and proposed a number of mitigations to the risks that NERL identified regarding capex incentives.

For the last factor, the CMA recognised Frontier's submission on behalf of the ENA on the topic of aiming up due to the asymmetry of getting the cost of capital too high and too low, and accepted there might be an argument that, in the long run, customers' interests were served by a small premium to the cost of capital. In particular the CMA stated:

> *"If there were positive externalities and longer-term benefits to consumers from identifying and investing in new capital projects, then we agreed that there could be a case for a long-term premium on the cost of capital."*

Even though the CMA has ultimately decided for NERL not to aim up, it has not taken a view on whether or not Frontier's view expressed in the report for the ENA would be justified in the energy sector. Ofgem's RIIO-2 settlement has the potential to leave a material amount of investment with positive externalities (such as environmental benefits) unexplored due to the possibility of setting the allowed return too low. Therefore, we believe that the framework set out by the CMA in the NERL case would lead a rational regulator to aim up in the context of the energy sector.

Aiming Up and its interactions with other mechanisms

The practical effect of this is that, going forward, we are now more likely to find companies facing more borderline investment decisions and more likely not to invest to eliminate delivery risk. However, Ofgem intends to go further than not aiming up, as owing to the outperformance wedge it intends to deduct from its central estimate, and thus aim towards the bottom of its range. Due to the magnified risk of aiming down (versus deciding not to aim up) any investment is discretionary in nature, and the commercial case for an investment is weak, it seems increasingly plausible – perhaps even likely – that companies will choose to not take on such projects. Areas of discretionary investment may include;

- **PCDs**: due to the nature of their arrangements, companies are likely to have a choice over whether to proceed with the delivery of a PCD at all, or whether to simply fail to deliver and have the sum clawed back. Where Ofgem aims down, and loads additional regulatory risk onto a project through ex post review, we are much more likely to see companies abandon PCDs rather than take on delivery risk and regulatory risk when there is potentially little to gain
- **Uncertainty Mechanisms**: Companies may decide in RIIO-2 not to bring forward a business case in a world where their primary incentive to invest – the allowed rate of return – has been set too low.

Overall effect on investment

As detailed in section 2.3.3 of Frontier's report, the combined effect of not aiming-up and other RIIO-2 mechanisms that have reduced the attractiveness of investments in the sector should not be underestimated. Under these circumstances, companies may have to just carry out the core aspects of their business. The commercial case for networks to play a leadership role, proactively seeking out opportunities to deploy capital in order to pursue service improvements, future efficiencies, new service, or progress towards environmental targets – including net zero – will have been significantly undermined. We note that despite these risks of not aiming up highlighted above, Ofgem is yet to carry out a formal impact assessment of its proposal to aim down. Now that the proposed full RIIO-2 package is visible through the DD, we urge it to do so.

Type 4 – New evidence presented on why Ofgem should aim up on the allowed return

6.3.5 Step 1 CAPM – implied cost of equity at 60% notional gearing

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?

SGN fundamentally disagree that energy networks will be exposed to similar systematic risk during RIIO-2 to water networks during PR19. Qualitative factors together with suitable European asset beta datasets and decomposition methodology shows that energy is riskier than water and should therefore have a premium reflected in the respective betas used to set the allowed equity return.

Furthermore, asset stranding is a particular risk for GDNs given uncertainties over decarbonisation. The GDNs are confident they will have a significant role in the future energy mix but until government policy decisions are made on the decarbonisation of heat and there is clarity on the decarbonisation pathway, there is significant uncertainty, especially in relative terms compared to the electricity sector where government policy has led to very significant investment in renewable generation capacity. Therefore, the long-term use of gas networks is not a far-off risk in the perceptions of investors. There is empirical and qualitative evidence that investors are currently appraising exposure to decarbonisation risks – this is risk which is far greater for gas networks than both water and other energy networks, and means GDNs have the greatest risk, as expanded upon in our answer to FQ6.

Ofgem's assumption that energy networks will be exposed to similar systematic risk during RIIO-2 to water networks during PR19 is primarily based on the following rationale;

- Ofgem cite CEPA's qualitative relative risk analysis showing pure play energy networks have several similar risk characteristics' as pure water energy networks (Finance Annex, paras 3.49 and 3.62)
- Ofgem states (DD Finance Annex, para 3.51&3.59) that evidence from the most relevant European comparators (Enagas, Red Electrica, Snam, Terne Rete, Elia and REN) supports, or even puts downward pressure, on their asset beta range (para 3.54) derived from the assumption that energy networks have similar systematic risk to water networks. They note;

  > *"if GB energy networks are exposed to higher levels of systematic risk than GB water networks, as argued by network companies, then reliable analysis of European comparators should help reveal this" (para 3.59)*

- Ofgem put's forward that CEPA's recomposition of the asset betas for NG's and SSE's regulated businesses matches long term GB water comparators (para 3.50), stating that (para 3.58);

  > *"if GB energy networks are exposed to materially higher systematic risk than GB water networks, as argued by network companies, then reliable de-composition analysis should reveal this"*

Consequently, Ofgem's current judgement that pure play energy networks bear similar systematic risk to pure play water networks (Severn Trent and United Utilities) is highlighted as key factor in its decisions on the asset and notional equity beta ranges (para 3.54). After step 2, market cross check adjustments, the midpoint equity beta calculated in the WACC allowance model exactly aligns with the 0.71 for the PR19 Final Determination.

Ofgem has included table 18 in the DD finance annex, which provides a qualitative comparison between regulated energy and water networks in GB. Overall Ofgem conclude that the water and energy networks have broadly similar levels of risk. While we cover many of the points raised in table 18 in our detailed responses to FQ5 and FQ6, we respond directly to some of the points raised by Ofgem in the table below. As we outline in these responses, we strongly assert that the both empirical and qualitative evidence suggests that energy is higher risk than water, and more specifically, gas is higher risk than the other energy sub sectors.

Ofgem introductory statement	Specific points raised by Ofgem	SGN response
Energy networks may bear lower systematic risk than water networks because...	... RoRE ranges appear smaller when comparing Figure 22 with Ofwat's FD. See also CEPA report for risk benchmarking ...	As examined in PwC's report 1, we view that many of the individual aspects of the DD have been miscalibrated which has skewed the risk to the downside. The results from PwC's analysis shows that the RoRE ranges are in skewed more to the downside than Ofwat's FD. There is also very limited scope for upside in the GD2 DD.
	... RIIO-2 involves greater use of indexation (debt, equity and RPE mechanisms limit systematic risks)	While indexation should help to limit risks to some extent, there remains risk around the selection of the appropriate indices, in particular for RPEs where risk has been increased due to poor selection of index (see response to Core Questions Q10). There are also risks associated with how the indexation is applied in practice,

		with Ofgem indicating they may need to revisit equity indexation during the price control. Furthermore, it would take substantial movements in the RFR to mean that Cost of Equity Indexation makes a significant difference, for example to cancel out the impact of the application of the outperformance wedge vs PR19 in a rising interest rate environment. Debt indexation in water is arguably better aligned to the risks around new debt issuance risks, whereas the Ofgem indexation approach using the whole cost of debt is more likely to result in greater mismatches between debt financing costs and the movement in the index.
	… Pension cost protection is considered more comprehensive for energy networks than water networks	SGN note that GDNs are exposed to the incremental deficit through the TIM mechanism so the difference in risk may not be that material.
	… energy networks appear to have lower totex: RAV ratios and lower incentive strength (see CEPA report)	As discussed in the table in the gas vs water risk section below, water networks appear to have higher operational gearing on this basis. However, we view that this is significantly outweighed by other systematic risks such as asset stranding risks. Gas networks also have greater incentive strength than water.
	… water networks face ongoing reputational and business risks around performance (e.g. leakage) which may cause higher systematic risk for water networks.	As discussed in the gas vs water risk table energy networks broadly face far greater and higher impact risks due the substances involved i.e. a gas explosion is more impactful than water leakage both in terms of safety and reputational damage.
Energy networks may bear similar systematic risk as water networks because…	... market observations of beta are typically very similar (see Figure 8)	As shown in Ofgem's Figure 8, the betas for National Grid and SSE are higher across most estimation measures
	… regulatory regimes and price controls (PR19 and RIIO-2) are very similar (see CEPA's relative risk comparison)	As discussed in the gas vs water risk table, SGN concludes that a number of aspects of the respective regulatory regimes have similar risk levels, but energy networks have higher risk when the asymmetric downside risk of the RIIO-2 package is taken into account (see RORE ranges point above).
	… investor value, as observed through Market to Asset ratios, is similar for both sectors (see Figure 19 and Figure 20)	As a consequence of non-regulated and non-UK business comparisons of public listed companies are difficult to interpret. As the three listed UK water companies are currently strong performers (being fast-tracked at the IAP stage of PR19), the listed company Market to Asset ratios are unlikely to reflect the ratios for the water industry as a whole. Furthermore, none of the gas networks are currently listed so there is no direct market evidence of the important impact of decarbonisation on Market to Asset, or beta values.
Energy networks may bear higher systematic risk than water networks because…	… of asset stranding (although CEPA suggest that it is difficult to reach a clear and unambiguous conclusion)	SGN views this as the most significant driver of risk differentials between water and energy, specifically gas. Again, please reference the gas vs water risk table below for a more detailed discussion.
	… the perception of political interference may be greater for energy networks	SGN agrees with Ofgem's assessment here.
	… technological uncertainty – and associated opportunities and	SGN agrees with Ofgem's assessment here given the pace at which technological change is occurring in the energy sector.

	challenges – may be greater for energy networks	
	… of market uncertainty for energy networks (eg net zero)	SGN agrees with Ofgem's assessment here.

Type 4 – New evidence presented on the qualitative risk of energy vs water

We now turn to focus on some of the above areas in more detail.

Qualitative Risk Assessment

As highlighted in section 3.3. of Oxera Report 1, increased focus on decarbonisation and rapid technological change provide reasons to believe that the fundamental risk of energy networks is greater than that faced by water networks These risks and uncertainties are clearly highlighted in Ofgem's 'Our Strategy for Regulating the Future Energy System' (2017). Furthermore, CEPA recognise that energy networks may have higher risk than water networks due to the uncertainty over the future long-term use of energy networks and the greater scope for change[546] and;

> *'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'*[547]

Thus, as a consequence, they state;

> *'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 networks are exposed to'*

The necessity to look at European asset beta comparators, as highlighted by CEPA, emphasises that energy and water network companies can't be assumed to have similar risk.

In conclusion since RIIO-1 and PR14 the uncertainty surrounding the future path of energy networks has significantly increased due to decarbonisation, the net zero target and the potential for rapid technological change, which should thus increase the relative risk between energy and water networks. This is reinforced by the fact that water is not subject to this uncertainty and the riskier areas of retail, bioresources and water resources are now more clearly demarcated from water networks.

Indeed, as detailed in section 3.3 of Oxera report 1, CEPA notes in Table 2.3 of its report[548] that energy companies are likely riskier than water companies in terms of demand, competition, and investment cyclicality. CEPA's Table 2.3 therefore identifies multiple dimensions on which energy companies may be riskier than water companies and no cases where the opposite is true. Table 18 on page 51 of Ofgem's report summarising the similarities in energy and water risk is much stronger than the actual claims in CEPA's report.

Type 1 - Factual or computational errors. Qualitative risk assessment shows that energy networks have higher systematic risk than water networks.

Type 4 – New qualitative evidence presented shows that energy networks have higher systematic risk than water networks.

Longer-term network use risk

This is the main driver of difference in relative risk between the energy and water sectors. There is limited risk around the long-term use of the water networks and their assets. People are expected to continue consuming water and using the networks in the same way they have for hundreds of years, which lowers the risk profile of water company assets.

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546 CEPA (2020), 'Beta Estimation Issues'. P38
547 CEPA (2020), 'Beta Estimation Issues'. P5
548 CEPA (2020), 'Beta Estimation Issues'. P25

However, the energy sector is undergoing fundamental changes and will continue to do so over the coming decades as the UK aims to hit its 2050 net zero carbon target. The type of energy that will be used to fuel the UK economy as well as the assets being used to transmit and distribute energy will change from its current make-up. This increases the likelihood that energy company assets will not be used over the long term, which in turn increases the risk of allocating capital to companies in the sector.

This view is strongly supported by investors, analysts and rating agencies. Last year, we asked PwC to survey a broad range of financial stakeholders to gather their views on various aspects of the RIIO-GD2 regulatory methodology. One of the topics covered was the relative risk of energy vs water. Interviewees generally viewed the energy and water networks as having 'broadly similar risk'. This was based on the belief that the regulatory and renationalisation risks were greater in water, with some of Ofwat's decisions in the run up to FD being poorly communicated and the water sector also being higher up the Labour party's 'renationalisation wish-list'. In contrast, interviewees suggested that on a fundamental basis the energy sector is riskier given the potential for asset stranding, which means the energy sector has 'higher medium to long-term risks'.

Considering these risk factors almost 1 year on, we observe that the two main factors behind stakeholders viewing the water sector as similar risk to energy have diminished. Certainly, the nationalisation risk, which was impacting the risk profile of the water sector more significantly than the energy sector, was all but removed by the 2019 General Election result (at least in the short-term). In addition, companies and investors now have far greater certainty and clarity over the regulatory framework following the PR19 FD (with the exception of the appealing companies), thereby reducing the regulatory risk faced by the majority of the sector. It is also important to recognise that the interviews with financial stakeholders were conducted in the run up to PR19 FD, which is clearly a time of elevated regulatory risk and uncertainty for stakeholders and companies.

In contrast, the asset stranding risk (i.e. the main factor driving higher risk in the energy sector relative to the water sector) is more important than ever, particularly as the Covid-19 pandemic and extreme weather events have brought environmental concerns into greater focus. With focus on reducing emissions increasing over the past year, the risk that assets in the energy sector become stranded has increased as the economy looks for alternative energy sources to gas in particular.

The GDNs are confident gas networks will have a significant role in the future energy mix but until government decisions are made on the decarbonisation of heat and there is clarity on the decarbonisation pathway there are significant uncertainties faced by the GDNs and their investors, especially in relative terms compared to the electricity sector where government policy has led to very significant investments in renewable generation capacity and hence providing confidence in the sector. This uncertainty is acknowledged in Ofgem's recent decarbonisation programme action plan[549] that includes a review of the major GDN investment programme (IMRRP) to ensure consumer money is best spent in light of net zero commitments.

Against this background, investors in GDNs (both existing and potential new providers of capital) are becoming more concerned about the risk of reducing natural gas demand. This risk has heightened since RIIO-GD1 due to the increased focus on the energy transition.

Therefore, in terms of the longer-term use of the networks, the energy sector is clearly significantly riskier than the water sector.

More recent evidence from equity analyst reports continues to support the evidence presented in the PwC survey:

- Jefferies[550] observe that water and energy are not comparable sectors given the investment required for decarbonisation, "We see Ofgem's current view of 4.3% cost of equity as significantly below the relevant regulatory benchmarks such as Openreach (5.3-5.9%) and Air Traffic Control (6.0%). Given the scale of investment required for the decarbonisation of energy networks, we see these sectors as more comparable to energy networks, as opposed to the UK water networks."
- Investec[551] estimates a cost of equity of 4.8% vs Ofgem's allowed return of 4.3% (pre-DD), which suggests they view equity returns should be higher. Investec also comment that "there are greater risks and challenges in energy that would support a higher allowed return than in water."

[549] Ofgem (2020), Ofgem's Decarbonisation Programme Action Plan, February 2020
[550] Jefferies (2020), SEE Plc Analyst report, 02 February 2020
[551] Investec (2020), National Grid Plc Analyst report, 03 July 2020

Type 4 – New evidence presented on the qualitative risk of energy vs water

Gas vs water

Given SGN's activities, we have also conducted a relative risk assessment of gas specifically vs water as outlined in the table below. . We outline the primary systematic risk drivers considered below (see the separate supporting document 'Full Response to Financial Question 6: Evidence of Systematic Risk Differential From RIIO-1 and Between Energy Sectors' for more detail on the framework);

- **Longer-term network use risk -** Networks more exposed to longer-term network use risks will have a higher risk profile.
- **Regulatory regime -** The regulatory regime has the potential to both increase and decrease exposure to systematic risk, through cost sharing, incentive setting and use of reopeners etc.
- **Operational gearing -** Networks with higher operational gearing as a consequence of lower capital intensity are more exposed to demand and cost shocks.
- **Scale of capital investment -** Ofgem suggested in RIIO-1 that larger investment programmes (relative to the rest of the business) can add to systematic risk.
- **Complexity of capital investment -** Ofgem suggested in RIIO-1 that more complex investment programmes can add to systematic risk.

In summary, the table below shows that gas is higher risk than water across 3 of the risk drivers, water is higher on 1, and the sectors are similar on 1 of the drivers. We observe that there is a trade-off between operational gearing impact (higher in water) and the impacts of decarbonisation, complexity and regulatory framework (higher in gas). SGN strongly considers that the impact of decarbonisation dominates.

Decarbonisation and the shift to net zero is a fundamental challenge and risk to the business over the longer-term. The empirical assessment of share prices and betas for companies exposed to carbon trends show substantial movements during RIIO-1, as shown in the separate supporting document 'Full Response to Financial Question 6: Evidence of Systematic Risk Differential From RIIO-1 and Between Energy Sectors'. The result is that companies, like gas networks, who are most at risk from decarbonisation trends face a higher and rising cost of equity. SGN believes the impact of decarbonisation is far greater than any differences due to operational gearing .On the basis of this, and other, evidence (such as the investor surveys and analyst reports outlined above), we view that gas companies require a higher asset beta and cost of equity than used in the water sector for PR19.

Systematic risk driver	Gas vs water
1. Longer-term network use risk	**Higher** As discussed in the above response to FQ5, this is the main driver of difference in relative risk between the gas and water sectors. There is limited risk around the long-term use of the water networks and their assets. The gas sector will be particularly impacted by net zero risks given the higher impact of decarbonisation relative to other energy sectors. This view is strongly supported by investors, analysts and rating agencies as outlined above. Additionally, our quantitative analysis of exposure to net zero risks in our response to FQ6 indicates that the asset stranding risks faced by gas networks translate into higher systematic risk. This comparison is just as relevant for comparison to water as it is to electricity distribution and transmission.
2. Regulatory regime	**Higher** There are a number of features of the regulatory regime which are consistent across the energy (specifically gas) and water sectors. Both will now operate through five year revenue controls and use a totex and incentives regime with a focus on outputs and outcomes. Regulators across both sectors set allowed returns using a similar overarching approach. The cost of equity is set using the same total market return assumption and index-linked gilts are used to infer the risk-free rate assumption. Betas are estimated using a different range of approaches and comparators, however, this is to be expected given that one is estimating systematic risk for companies in different sectors. On the cost of debt calibration, regulators in both sectors make use of debt indexation although Ofwat use indexation only for the new cost of debt, while Ofgem proposes to use a trombone mechanism that

	captures all debt costs. The approach to indexation around the cost of debt is arguably greater risk in energy as the index applies to the whole cost of debt, whereas the risk to the notional water company is around the new debt issued in the forthcoming price control period. The mechanics of the operation of the revenue control are broadly consistent across sectors with movement towards annual iteration/reconciliation process used to make revenue adjustments. Also it would take substantial movements in the RFR to mean that Cost of Equity Indexation makes a significant difference, for example to cancel out the impact of the application of the outperformance wedge vs PR19 in a rising interest rate environment. There are some further features of the Ofgem approach which theoretically may reduce risk, for example RPE indexation. However risk has been increased due to proposed RPE indexation due to poor selection of index (see response to Core Questions Q10).. There are also additional risks in the energy regime, particularly in the way it has been calibrated. Totex incentive rates are higher in gas than for water and Ofgem has set the efficient company benchmark at the 85th percentile for GD companies, which represents a change from RIIO-1 (and other regulatory norms) where it was set at the 75th percentile. Likewise, Ofgem's productivity challenge of 1.2% for capex and repex, and 1.4% for opex is higher than all recent regulatory precedents. Along with other regulatory decisions in the draft determinations, this means the degree of stretch and downside risk is greater for gas networks. PwC's analysis of downside risk (see PwC report 1 for full detail on risks) shows that many regulatory parameters of the RIIO-GD2 regulatory regime are skewed to the downside. On balance, we view that these additional downside risks mean that the RIIO-2 regulatory regime risk is somewhat higher than PR19.
3. Operational gearing (from lower capital intensity).	**Lower** As shown in Figure A1 in CEPA's beta estimation report, water companies in PR19 have higher operational gearing than RIIO-GD2 based on the totex : RAV ratio. In particular, this is driven by higher opex instead of capex. While we have not conducted analysis for all of the water companies across every measure of operational gearing that we have used in the relative risk analysis for the energy sector (see response to FQ6), we conclude that based on this specific measure, water has higher operational gearing than gas, and therefore has higher systematic risk on this basis.
4. Scale of capital investment	**Similar** The scale of capital investment across the energy sub sectors and the water sector is also shown in Figure A1 in CEPA's beta estimation report. Despite the water companies having higher totex: RAV ratios, this is largely driven by higher opex in the water sector. In terms of the capex: RAV ratio, gas (approximate average of 5%) is marginally lower than water (approximate average of 7%). We also expect capex in the gas sector to increase as the transition to net zero gathers pace over the course of RIIO-2. However, as outlined in the subsequent section (response to FQ6), we do not consider the scale of capital investment to be a relevant driver for the purpose of assessing differences in risk across sectors. This is because the scale of capital investment defines the asset base upon which returns are earned, rather than the risk to that investment. (See separate supporting document 'Full Response to Financial Question 6: Evidence of Systematic Risk Differential From RIIO-1 and Between Energy Sectors').
5. Complexity of capital investment	**Higher** Both gas and water networks are required to operate to a very high safety standard. Both have their different complexities and as with the energy sector, this is largely reflected in the allowances for specific operations or projects i.e. additional complexity is factored into the allowances for a given project. However, gas is an inherently riskier substance than water, with higher necessary safety standards which drives complexity and cost. Transporting gas must been done in a more controlled and exacting way than transporting water. While the probability and frequency of explosions is thankfully low, the potential impact is far greater than a comparable adverse water event, such as leakage.
6. Conclusion	**Higher** Across 1 of the 5 drivers of systematic risk, gas has a lower level of systematic risk to water. Across 1 of the 5 drivers of systematic risk, gas has a similar level of systematic risk to water. Across 3 out of the 5 drivers of systematic risk, gas is riskier than water.

	We observe that there is a trade-off between operational gearing impacts (higher in water) and the impacts of decarbonisation, complexity and regulatory framework (higher in gas). SGN strongly considers that the decarbonisation impact dominates. . Decarbonisation and the shift to net zero is a fundamental challenge and risk to the business over the longer-term. The empirical assessment of share prices and beta for companies exposed to carbon trends show more substantial movements compared to differences in operational gearing (which have always been present in beta estimates).

Type 1 - Factual or computational errors in DD Finance Annex on relative risk of energy sectors

Type 4 – New evidence presented on the qualitative risk of gas vs water

European Asset Beta Assessment

Ofgem's statement that evidence from the most relevant European comparators supports, or even puts downward pressure, on their asset beta range derived from the assumption that energy networks have similar systematic risk to water networks, is entirely dependent on the European energy networks chosen by CEPA for the dataset. CEPA have chosen a dataset of Enagas, Red Electrica, Snam, Terne Rete, Elia and REN whilst Oxera have the same comparators apart from excluding Elia and REN.

Liquidity is a key factor to determine whether a European energy network asset beta is reliable and thus should be included in the dataset. As detailed in section 3.1.2 of Oxera Report 1, Oxera have analysed the liquidity of the comparators in CEPA's sample in order to form a more robust view of the set. As liquidity is a difficult concept to define and is subject to interpretation, it is useful to look at a wide range of measures. In particular, the following liquidity measures were considered:

- Bid ask spread as a percentage of closing price: the lower the spread the more liquid the stock on the basis it shows there are a large number of buyers and sellers in the market
- Share turnover: The higher the share turnover, the more liquid a stock. For example, a high trading volume would indicate that a stock can be bought and sold easily.
- Free float: a small proportion of shares floated would create an impediment to active trading, indicating a less liquid stock

Table 3.1 of Oxera's report shows that on all 3 measures REN and Elia are the most illiquid, and for bid ask spread and share turnover they are significant outliers and thus should be excluded from the sample. It's worth noting Oxera's point that CEPA's liquidity analysis compares a broad sample of European energy companies, most of those companies appear to be illiquid; hence, the benchmark for the liquidity filters is affected by the sample choice. We believe the correct approach would be to compare REN and Elia to liquid comparators, which would then lead to the exclusion of those companies from the final European sample.

Type 1 - Factual or computational errors. European asset beta assessment shows that energy networks have higher systematic risk than water networks.

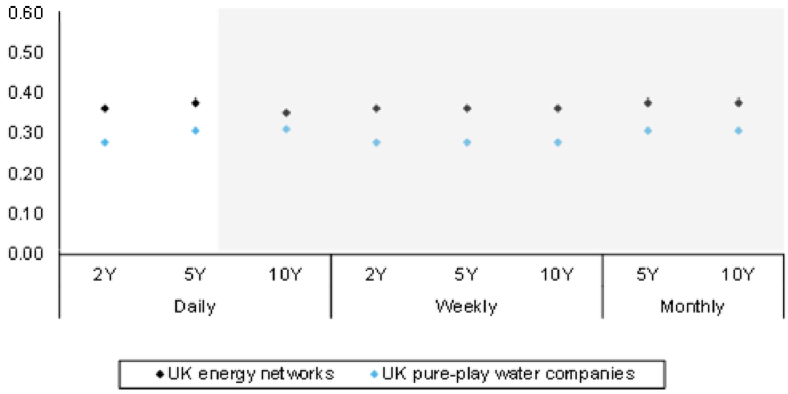
Type 4 – New European asset beta evidence presented shows that energy networks have higher systematic risk than water networks.

Asset Beta Decomposition

CEPA's analysis of the practical issues surrounding decomposition of group asset betas and subsequent recomposition analysis fails to pick up that 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 it reflects elements of lower risk faced by National Grid's US business, as it operates under Rate of Return Regulation. Thus, it is a conservative assumption to use NG's asset beta. As shown by the following graph NG's asset beta has consistently been higher than the average asset beta of the two pure play water companies (United Utilities and Severn Trent);

Comparison of asset beta for UK energy networks and UK pure-play water companies[552]

[552] Oxera Report 1, Figure 3.7



Type 1 - Factual or computational errors. Asset beta decomposition assessment shows that energy networks have higher systematic risk than water networks.

Type 4 – New asset beta decomposition assessment evidence presented shows that energy networks have higher systematic risk than water networks.

Conclusion

In conclusion, a qualitative risk assessment shows that energy networks are inherently riskier than water networks (with gas having the highest differential due to being at greatest risk from decarbonisation), which is reinforced when a suitable European energy network comparator dataset is used. Furthermore, when using NG's asset beta to represent its UK regulated networks, which as shown is a very conservative assumption due to the lower risk of US networks, the NG asset beta also shows that energy networks are riskier than water. Therefore, SGN firmly believe energy networks will hold higher systematic risk during RIIO-2 than water networks during PR19.

Furthermore, it should be noted it is clear that the beta in the CAPM equation does not reflect the full level of risk faced by UK energy networks. Ofgem notes in para 3.60 of the DD Finance Annex that it is unconvinced by arguments reflecting alleged CAPM failings or alleged risks that are not captured. In response, Oxera notes in section 3.3 of Oxera Report 1 that they no longer aim at the top end of a range for beta based on market data. Also, they explain that CAPM failings are not alleged, they are well-known in the academic literature, including in papers cited by CEPA (i.e. Fama and French (1993). Although their analysis uses the CAPM due to regulatory precedent, they take the view that multiple risk factors are uncaptured by this methodology and Oxera explore one of them in their report (political/regulatory risk and associated skewness).

Oxera's analysis, in Sections 3.4 and 3.5 of Oxera Report 1, highlights the increase in political and regulatory risk due to four factors;

- more frequent political and regulatory news triggering share price falls
- an increase in share price volatility since 2016—a period during which the UK Labour party has asserted its policy of renationalising utilities if it were to come to power
- a decline in the status of National Grid and other regulated utilities as 'defensive stocks';
- an increased focus on regulatory and political risk as a valuation driver in analyst assessments

It also evidences how the beta of regulated utilities eliminating regulatory and political announcements is, on average 0.03 lower. The report shows how the political and regulatory risk manifest themselves in stock returns with consistently sharp declines in energy firm's stock prices relative to the market as a whole, a concept known as negative skew. Academic literature demonstrates that investors require a premium for holding such stocks. Oxera further state [553]

> *'As noted collectively in the Ofgem and CEPA reports, regulated energy companies bear a number of potential serious downside risks, such as nationalisation, cybersecurity risk, and technological changes. Conversely, any outperformance has the potential to be capped by regulators, seemly removing any offsetting upside for a rational investor'*

[553] Oxera Report 1, section 3.5

This tendency to hold limited upside but the probability of large downside risks, combined with recent academic evidence documenting that the CAPM underestimates the CoE for low-beta firms, suggests that using the CAPM beta alone ignores important risk factors faced by regulated energy firms and that a point estimate should be selected towards the high end of the asset beta range.

Type 5 - Evidence that SGN has provided but hasn't been taken into account or given sufficient weight

Type 4 – New evidence presented of the impact of political and regulatory risk on asset betas, including the concept of negative skew.

FQ6. Is there evidence of a material difference in systematic risk between:
a. RIIO-1 and RIIO-2,
b. distribution and transmission networks,
c. gas transmission and electricity transmission,
d. gas and electricity?

In summary, based on these drivers of systematic risk and our empirical analysis, we consider that GDNs require an uplift to their asset beta to account for the higher systematic risks they face relative to the other energy subsectors, driven primarily by having the greatest exposure to decarbonisation through long-term asset risks. The evidence shows that:

A. RIIO-1 vs RIIO-2: RIIO-2 is higher risk

The regulatory regime has introduced some new features which have reduced some risks, but leaves other new and emerging uncertainties. Moreover, we note that Ofgem's DD for RIIO-GD2 has introduced significant asymmetric downside risk across many aspects of the regulatory framework compared to RIIO-1 (See PwC report 1), which exposes companies to greater levels of systematic risk. In addition, our empirical analysis shows that on average (across different estimation approaches) asset betas have increased by 0.07 percentage points since the commencement of RIIO-GD1. We therefore conclude that there is strong evidence of higher systematic risk in RIIO-2 than in RIIO-1.

B. Distribution vs Transmission: Distribution is higher risk

Across the measures of systematic risk, distribution has higher operational gearing than transmission. Likewise, transmission companies also benefit from greater uncertainty mechanisms, which reduce their exposure to systematic risk. Gas distribution also has a higher TIM incentive rate of 50% compared to 36% for gas and electricity transmission, and therefore GDNs face higher exposure to all totex risks (including systematic risks). We therefore conclude that distribution faces higher relative risk.

C. Gas Transmission vs Electricity Transmission: GT is riskier than ET

As a gas distribution company, SGN does not have firm views on the difference across gas transmission and electricity transmission. Across our risk measures, Gas Transmission has higher long-term asset use risk, but benefits from more Uncertainty Mechanisms. SGN considers the energy transported by the networks is a more important driver of risk than the stage in the value chain. This is addressed in part D below.

D. Gas vs electric networks analysis: Gas networks are riskier

Across our relative risk measures, Gas has higher long-term asset use risk and higher operational gearing, as well as lower potential use of Uncertainty Mechanisms and higher TIM incentives rates. This is supported by empirical evidence that GDNs have higher asset betas than other energy networks.

See the below table for our summary conclusions. Our full response to question FQ6 is to be found in the separate supporting document 'Full Response to Financial Question 6: Evidence of Systematic Risk Differential From RIIO-1 and Between Energy Sectors'.

Systematic risk driver	A) RIIO-2 vs RIIO-1	B) Distribution vs transmission networks	C) Gas transmission vs electricity transmission	D) Gas vs electricity
1. Longer-term network use	**Higher** Quantitative analysis of asset betas	**Similar** While the evolution of	**Higher** Using CEPA's sample of European comparators, we compare	

Systematic risk driver	A) RIIO-2 vs RIIO-1	B) Distribution vs transmission networks	C) Gas transmission vs electricity transmission	D) Gas vs electricity
risk	indicates that an uplift of 0.05 to 0.11 to the asset beta since RIIO-GD1 is appropriate. The net zero policy is now far more urgent and takes a higher priority in Ofgem's refreshed strategy. Over RIIO-1, our analysis indicates that the asset beta of high carbon firms has increased dramatically, forming a current 0.70 wedge in both equity betas and asset betas from low Carbon companies.	the industry may put more or less pressure on local distribution vs national infrastructure, SGN considers the energy transported by the network is a more important factor.	the asset betas of GDN vs electric companies. Our quantitative analysis indicates that an uplift of 0.045 to 0.055 to the asset beta is appropriate for gas networks. Furthermore, our analysis of exposure to net zero risks indicates that an uplift of 0.075 to the asset beta is appropriate for gas networks. This directly relates to the elevated exposure to policy uncertainty and higher risk of asset stranding risk of gas networks relative to electricity. Inferences from this suggests that there is a relatively higher risk of gas distribution and transmission, relative to electricity transmission and distribution.	
2. Regulatory regime	**Higher** Some elements have reduced risk but RIIO-2 has introduced new uncertainties including how the new mechanisms will work in practice, how the regulatory regime will respond to new and emerging risks, such as net zero transition, and how companies will respond to a much more challenging overall determination with a shift away from ex-ante incentives. Moreover, across many aspects of the RIIO-2 regime the risk profile is skewed to the downside, which means companies are more exposed to systematic risk. For example, Ofgem has set the efficient company benchmark at the 85th percentile for GD companies and companies also face financial output delivery incentives (ODIs) which are asymmetrically skewed towards downside risk.	**Higher** Broadly similar overarching regulatory framework across sectors. On average, GT and ET companies have 5.0x higher UMs as a proportion of Totex than GDNs, significantly reducing their relative risk (i.e. one way UMs reduce risk is by being determined closer to delivery/post delivery allowing less price risk. Distribution has higher incentive rates than Transmission.	**Similar** Broadly similar overarching regulatory framework across sectors. GTs & ETs have 13.3x and 2.2x higher UMs as a proportion of Totex than GDNs respectively, significantly reducing the risk of GT. GT and ET have very similar TIM incentive rates.	**Higher** Broadly similar overarching regulatory framework across sectors. On average, ETs have 64% of the UMs as a proportion of Totex relative to GDNs - but this is all driven by NGGT TO, otherwise they have 2.2x higher UMs than GDNs. Gas has higher TIM incentive rates
3. Operational gearing (from lower capital intensity).	**Similar** There has been little movement in cost structures over RIIO-1.	**Higher** On all 4 measures of operational gearing considered by the CMA, gas distribution has higher operational gearing in RIIO-2 than both gas and electricity transmission.	**Similar** The evidence is mixed with GT sometimes having higher operational gearing while under other measures ET has higher operational gearing.	**Higher** GDNs has higher operational gearing than ETs and GTs across all four measures. The evidence is mixed when comparing GTs and ETs, with GT sometimes having higher operational gearing while under other measures ET has higher operational gearing.
4. Scale of capital investment	**Similar** More increases in electricity, but small reductions in the scale of investment in gas.	**Similar** We do not consider the scale of capital investment to be a relevant driver for the purpose of assessing differences in risk across sectors. This is because the scale of capital investment defines the asset base upon which returns are earned, rather than the risk to that investment.		
5. Complexity of capital investment	**(Slightly) Higher** Some capital projects have been able to use more complex techniques.	**Similar** Both transmission and distribution have their different complexities.	**Similar** Both electricity and gas networks are required to operate to a very high safety standard. Both have their different complexities; however this is largely reflected in the allowances for specific operations or projects i.e. additional complexity is factored into the allowances for a given project. Fundamentally, many of the processes are similar in nature.	
6. Conclusion	**Higher**	**Higher**	**Similar**	**Higher**We conclude that gas is

Systematic risk driver	A) RIIO-2 vs RIIO-1	B) Distribution vs transmission networks	C) Gas transmission vs electricity transmission	D) Gas vs electricity
	We conclude that RIIO-2 is risker than RIIO-1. Across 3 of the 5 drivers of systematic risk, RIIO-2 is riskier than RIIO-1. Across 2 of the 5 drivers of systematic risk, RIIO-2 has a similar level of risk to RIIO-1..	We conclude that distribution is riskier than transmission. Across 2 out of 5 drivers of systematic risk, distribution is riskier than transmission. Across 3 of the 5 drivers of systematic risk, distribution is a similar level of risk to transmission.	We conclude that gas transmission and electricity transmission have similar levels of systematic risk. Across 4 of the 5 drivers of systematic risk, gas transmission is a similar level of risk to electricity transmission. Gas transmission is riskier than electricity transmission in one of the drivers of systematic risk. Overall, gas transmission has higher long-term asset use risk, but benefits from more uncertainty mechanisms.	riskier than electricity. Across 3 out of 5 drivers of systematic risk, Gas is riskier than Electricity. Across 2 of the 5 drivers of systematic risk, gas is similar to electricity.

One comparison not specifically requested in this question is between gas transmission and gas distribution activities. Both sectors face the risks relating to decarbonisation, but the precise way in which decarbonisation places different challenges on the two systems is difficult to judge at this stage.

From our analysis above, this means observations around operational leverage and the regulatory regime are therefore most instructive to compare the sectors. Our conclusion in the table above is that distribution activities are higher risk through higher operational leverage, higher TIM cost sharing rates and less comparative use of Uncertainty Mechanisms. We therefore conclude that gas distribution has higher risk than gas transmission activities.

Type 4 – New evidence presented on the quantitative and qualitative risk of gas vs electricity

6.3.6 Step-2: Cross-check implied cost of equity at 60% notional gearing

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

SGN believe that the concerns the CMA has identified re: WACC increasing with gearing can be addressed by the use of new cost of debt only in the cross check, as per Modigliani and Miller's model, and a more realistic RFR assumption, as detailed below.

An important solution to the concerns the CMA has identified regarding the relationship between WACC and gearing is that the forward-looking cost of debt should be used as assumed by Modigliani and Miller. Therefore, a more appropriate figure would be the spot iBoxx AAA/B or the utilities 10+, i.e. a circa. 1.89% nominal rate which is 0.13% real–assuming a 2.02% CPIH, rather than the 1.74% CPIH real cost of debt assumption that Ofgem use.

Furthermore, the violation of the MM model cited by the CMA is also considerably mitigated if a more realistic RFR is used than the underestimate proposed by Ofgem. Notwithstanding the fundamental reasons why Ofgem's CAPM RFR methodology needs to be revised, as set out in response to FQ4, if the methodology is not revised a long run RFR should be used to test the MM theorem as the current historically low RFR spot rates are showing abnormal divergence from corporate bonds.

When the MM model is applied post these changes the WACC is roughly constant with gearing, as shown in section A2.6 of Oxera report 1.

In any event, we believe the 'alternative model' proposed by the CMA on adjusting the asset beta to achieve a constant WACC with gearing is problematic, as it is contrary to finance theory. Our concerns may be summarised as follows:

(i) Given the complexities considered by regulators, it would be surprising for regulatory cost of capital relationships to conform perfectly to the relationships set out in the MM paper. This was pointed out by Ofwat when it observed 'while noting the CMA's finding that an asset beta which varies with gearing may achieve a WACC which is constant we have concerns that a gearing-invariant WACC may not be a good approximation for circumstances in of the water sector, due to the presence of important features of the regulatory framework which are not captured in the Modigliani-Miller theorem.'[554]

(ii) In the CMA's alternative model (inspired by the MM framework), setting the cost of capital to be independent of gearing requires the asset beta to be flexible to adjust with gearing. This runs counter to established financial theory and practice. The asset beta, by definition, is a measure of the systematic risk of the assets themselves and not any additional equity risk introduced through leverage in the capital structure. It should therefore be constant irrespective of actual or notional capital structure. While the asset beta cannot be estimated directly (unless firms have no debt financing), once the asset beta has been estimated, it should not vary with financial gearing. I.e. the equity beta is determined by the asset beta and gearing and not the reverse.

Type 1 - Factual or computational errors regarding the application of the MM modelling of WACC and gearing

Type 4 – New evidence presented regarding the application of the MM modelling of WACC and gearing

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

SGN believe there have been a number of fundamental errors in the CAPM cross checks as set out by Ofgem in the DD, and a number of alternative cross checks that should be used, as detailed in the rest of this question including asset and debt risk premium comparisons and broker coverage of listed equity that show the cost of equity is set too low.

<u>Ofgem's Proposed Cross Checks</u>

WACC cross check:

We believe the cross check that WACC should be invariant to gearing is flawed due to the following factors, which are detailed in our response to FQ7;

- the use of spot RFRs
- the use of embedded debt as the MM theorem uses current borrowing rates
- the fact that it goes against financial theory flexing asset beta to achieve a constant WACC.

Type 1 - Factual or computational errors regarding the application of the MM modelling of WACC and gearing

Type 4 – New evidence presented regarding the application of the MM modelling of WACC and gearing

MARs

As set out in section A2.5 of Oxera report 1, Ofgem contends that market equity valuations of three listed water companies (SVT, UU, PNN) support Ofwat's allowed equity return for PR19. In particular, Ofgem relies on analysis from CEPA that indicates premia of about 20% to 40% at three spot dates, thereby suggesting that the PR19 Final Determination allowed return on equity (i.e. 4.19% in CPIH-real terms) is more generous than market expectations. Ofgem also presents some stylised modelling of the MAR-implied cost of equity under different levels of expected regulatory outperformance, and a time-series analysis of observed MARs since 2007. Together, Ofgem finds the evidence from MARs to be a 'persuasive' cross-check for the CAPM-derived cost of equity. As set out in the same section of the Oxera report, Oxera state that

> *'In our May 2020 submission to the CMA as part of the water PR19 appeals [Oxera Report 3], we concluded that uncertainty over the sources of value premia, and their respective valuations, makes it impossible in this*

[554] Ofwat, '*Reference of the PR19 final determinations: Risk and return – response to common issues in companies' statements of case.*', May 2020, p72-73.

case to infer the cost of equity with a meaningful confidence level to make such inference reliable and robust for regulatory purposes.'

Based on their research Oxera, as set out in section A2.5 of Oxera Report 1, believe there are five key issues with Ofgem/CEPA's analysis of MARs that means that Ofgem's assertion that evidence from MARs is a 'persuasive' cross check for the CPAM-derived cost of equity is invalid;

- **Observed premia can explained without recourse to an assumption that the market cost of equity is lower than Ofwat's allowed return:**

  Ofwat has raised the bar for service targets and incentives for AMP7 which makes industry wide outperformance unlikely. However, as evidenced in section 4 of Oxera report 3, some companies, including ST and UU, are expected to outperform;

    - Both companies are better positioned to outperform their totex allowances than the wider industry as both companies face efficiency challenges on their totex plans which are lower than the industry-level average efficiency of 5% imposed by Ofwat;
    - Analyst expectations is also that both companies outperform on ODIs
    - Both are forecast to have a lower cost of debt than the Ofwat allowance;
    - The business plans of both UU and ST were fast tracked, Ofwat stated that 'This status gives them reputational, procedural and financial benefits' and specifically includes an additional 10bps on Ofwat's allowed base return over PR19;

  It is important to note that just because Severn Trent and United Utilities are expected to outperform this does not mean the whole sector is systematically expected to outperform. In fact, Moody's has recently downgraded many of the water companies leaving the sector on negative watch. Oxera Report 3, section 4, evidences how the other factors explain the residual outperformance, including takeover premium, pension funding, revenue adjustments from previous price controls, accrued dividends and market sentiment and volatility in share prices.

- **Ofgem/CEPA's stylised analysis disregards drivers of RCV premia other than outperformance and allowed returns:** Ofgem/CEPA assume that observed premia are driven by two factors: outperformance and a market cost of equity that differs from Ofwat's allowed return. This analysis ignores several other drivers of listed RCV premia, including (but not limited to) the values of the non-regulated businesses, revenue adjustments due to PR14 reconciliations, investor expectations of future dividends, and expected takeover premium. Ofgem/CEPA cite the UKRN study to support their rationale. However, the UKRN study looked at transaction premia of private companies who by definition do not have share prices that reflect daily market sentiments. The UKRN study argues that 'pure-play utilities are generally not subject to the issues of control premium and winners curse, though there remains the challenge of understanding the unobserved investor assumptions.'[555] Ofgem has also previously taken a more cautious position about drawing inferences from observed premia of listed companies[556]:

  > *'We do exercise some caution when considering market-to-asset ratios. Firstly, there may be limited information in listed share prices as these stocks could, particularly in the short-run, be influenced heavily by wider market "noise"'. Second, as noted in the UKRN Study by Burns, any premium on corporate transactions could, at least in part, reflect (i) a control premium; or (ii) a winner's curse'*

  The inclusion of additional drivers of RCV premia can explain observed premia without requiring the assumption that the market cost of equity is lower than Ofwat's allowed return.

- **Market expectations of higher returns after AMP7 can help explain the premia currently observed:**

  Cost of Equity for PR19 and RIIO-2 are at an historic all time low, so its not inconceivable that investors rationally expect somewhat higher allowed return in future price controls.

- **CEPA estimate premia for two energy companies (National Grid and SSE) that are not 'pure-play':**

CEPA have included National Grid and SSE in their MARs analysis, whilst recognising they are not pure play. We disagree with CEPA that NG and SSE should be included in the analysis as neither firm being 'pure-play' further compounds the already high level of uncertainty in the MAR analysis.

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[555] UKRN (2018), 'Estimating the cost of capital for implementation of price controls by UK Regulators', 6 March, p. 13.
[556] Ofgem (2012), 'RIIO-2 Sector Specific Methodology Annex: Finance', 18 December, p. 44, para. 3.127.

- **CEPA's time-series analysis of premia suffers from estimation issues:**

CEPA provide a time-series analysis of RCV premia for SVT, UU and PNN from 2007 until present. It shows an average RCV premium for SVT and UU of 10-15% and 1% for PNN over the period. However, a time-series type of analysis is not suitable for RCV premia as the frequency of the data used in in the numerator and denominator is not consistent. Share prices in the numerator are updated regularly and can be easily observed on a day-to-day basis. Instead, the denominator is the RAB which is updated annually. The mismatch in the frequency of the numerator and denominator introduces estimation error to time-series observations of RCV premia.

It is not clear how to explain the negative RCV premia observed for PNN over multiple periods lasting several years. Estimation error inherent in this time-series analysis; the value of PNN's non-regulated business; and lower market expectations on future outperformance are potential explanations. Nonetheless, it is inconsistent to draw conclusions about the adequacy of Ofwat's allowed returns based solely on the positive RCV premia observed for SVT and UU over time and not give weight to PNN

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. Further detail on the CMA precedent on MARs can be found in section 2 of Oxera Report 3.

Type 1 - Factual or computational errors. MARs is not a persuasive cross check of the CAPM derived cost of equity

Type 4 – New evidence presented including how caution should be applied when using MARs as a cross check to cost of equity given the forward-looking nature of this metric, how the premia can be explained without recourse to the cost of equity, market expectations of cost of equity beyond AMP7 may well be higher than the PR19 cost of equity and the limitations of CEPA using 3 spot dates for evidence.

OFTO:

OFTOs projects are operational assets with a very different risk profile compared to the onshore energy networks regulated by RIIO-2. In particular, the net cash flows are largely fixed in real terms over the duration of the OFTO tender revenue stream. As such, we consider that any comparison of asset risk is likely to significantly underestimate the cost of capital for a network that undertakes capital and replacement expenditure in addition to operational expenditure. Factors that show energy networks have much higher risk include;

- They have delivery risk for ongoing construction programmes – unlike OFTOs whose assets have already been constructed
- Construction risks are not protected
- Significant ongoing financing activity
- 45-year recovery horizon vs 25 years
- Higher safety risk
- Larger workforce means greater exposure to employer risk
- Higher political risk exposure

Furthermore as, highlighted in section A2.1 of Oxera report 1, OFTOs are an asset class that have matured over period that Ofgem has analysed, which could explain much of the reduction in IRR from 10.2% in 2012 to 7.0% in 2019. Oxera also point out in this section the following factors which also mean the OFTO data is an inappropriate for a cross-check for regulatory purposes

- they have never been able to replicate this cross-check because the data have never been publicly released.
- conceptually, Ofgem assumes a terminal value of zero at the end of the expected project life. If the successful bidders assumed positive net cash flows after the end of the contracted revenue period, the implied IRR would be higher.

Type 1 - Factual or computational errors. OFTOs are operational assets with a very different risk profile than onshore energy networks regulated by RIIO-2, and therefore they have limited value as a cross check

Investment Managers (TMR) Cost of Equity

The Investment manager cross check has fallen from 5.5% in the Sector Specific Methodology Decision to 5.0% (CPIH, real). As set out in Section A2.4 of Oxera Report 1, we have the following concerns with Ofgem's analysis;

- The TMR estimates produced by investment managers have a primary aim of providing prudent estimates of future returns to their clients, to ensure that clients are managing their finances prudently. This is mainly a function of the regulatory framework, namely the FCA Conduct of Business Sourcebook, section 13, which states the maximum rates of return that financial services companies must use in their calculations when providing retail customers with projections of future benefits:

  'Firms are required to use rates of return in their projections that reflect the performance of the underlying investments, but the ceilings imposed by the FCA aim to prevent consumers being misled by inappropriately high rates'.

  This suggests that at best this evidence should be regarded as providing a lower bound on the expected compound rate of growth in the value of an investment in the equity market.

- If any weight is to be placed on this evidence in deriving the discount rate appropriate for setting the cost of equity allowance, an upward adjustment has to be made to correct for the downward bias arising due to geometric averaging. As explained by Cooper (1996), both the geometric and arithmetic averages are likely to be downward-biased estimators of the discount rate.

- Ofgem itself notes that many of the reports from the same investment manager are not comparable between the two periods. Oxera agree with this and state the changes in the timing and/or market index appear to explain the perceived decline in TMR claimed by Ofgem's TMR cross-check. We also note that Ofgem appears to double-weight this evidence, using it first to calculate the TMR and then as a cross-check

- Nearly the entirety of the decline in Ofgem's estimated TMR is due to a change in the investment horizon for Schroders. If the original horizon had been used for comparison, Ofgem would have reported a TMR of 7.90% rather than 4.90%. In addition to changing the investment horizon from 30 years to 10 years, Schroders also calculates its UK estimate using US data. Oxera understand that Ofgem has changed the investment horizon to match its other data points. However, we again note that this new value is an extreme outlier which is also based on a projection from US data. Given the obvious data outlier and the fact that this is not a direct UK estimate, Oxera's stance is that this data point should be disregarded.

- the other datapoint that exhibited a strongly negative change is Blackrock's estimate. As noted by Ofgem, this is not a like-for-like comparison as Ofgem changes from an EU TMR in December 2018 to a UK TMR in December 2019. Oxera were unable to find the December 2019 report, but state Blackrock's current analysis suggests that it projects lower returns due to expected declines in corporate earnings and dividend yields, not because market risk has decreased.

  Oxera note that without the Schroders and Blackrock data points, the TMR estimated by investment manager reports remains unchanged, or even slightly higher. In light of the shortcomings of using these estimates to inform cost of capital calculations, they can't recommend placing any weight on this evidence.

Type 1 - Factual or computational errors. The reports used for the DD analysis are not on a comparable basis with those used for the SSMD

Type 4 – New evidence presented including how most of the decline in Ofgem's estimated TMR is due to a change in the investment horizon for Schroders and shortcomings in negative movement (Blackrock)

Infrastructure Fund IRR:

Our overriding concern with this cross check, as detailed in section A2.2 of Oxera Report 1, is that the asset classes and the risk of the diversified portfolios differ significantly to a 'pure-play' energy network business. Therefore, funds' discount rates are not an appropriate benchmark for the cost of equity in RIIO-2 due to the fundamental differences in the risk profile.

In section A2.2 of Oxera report 1, Oxera note Ofgem's earlier use of infrastructure funds reported each fund's stated discount rate. Ofgem now uses each fund's discount rate and then deflates it using the market premium to the latest report net asset value (NAV). This 'implied IRR' is then used a cross-check to support Ofgem's CoE. The rationale provided by Ofgem is the same as for the MAR arguments as discussed above. Specifically, Ofgem assumes that any premium above NAV means that the fund is overestimating its own cost of capital. As also noted above, there are multiple explanations for a market premium that do not rely on the overestimation of cost of capital. In particular the NAV reported by each fund may take a more prudent view of future cash flows relative to market expectations.

Furthermore, Oxera set out how the average implied TMR of 17% (estimated from each funds CoE, beta and RFR), with high variation, and the lack of consistency between their betas and CoE, suggests that this data is unreliable for an energy network cost of equity cross check.

Type 1 - Factual or computational errors. Infrastructure funds asset composition makes them less risky than energy networks.

Type 4 – New evidence presented shows how the asset classes, and the risk of the diversified portfolios, share no similar characteristics to a 'pure-play' energy network business, and how the data used is unreliable for an energy network cost of equity cross check.

CAPM with 0.9 equity beta & investment managers' TMR

The concerns with the Investment Managers TMR highlighted above are just as valid for this cross check as the only difference is applying the equity beta.

Further Cross Checks

SGN believe that Ofgem should be using a number of more appropriate and rigorous cross checks to determine the CAPM cost of equity. This includes a check of the level of the asset risk premium to the debt risk premium. We submit a new report by Oxera on this matter (Oxera report 4), which reflects on, and updates for, Ofgem's previous review of this fundamental cross check. Furthermore, we review recent estimates of the RIIO-2 cost of equity by finance practitioners and reflect on the number of fundamental changes in cost of equity methodology that are proposed to be introduced in one price control.

Further cross checks - Asset Risk Premium Relative to Debt Risk Premium

The asset risk premium (ARP) reflects the excess return required by investors in return for providing capital to risky assets, and the debt risk premium (DRP) reflects the excess return required by investors in return for acquiring risky debt, and the differential between the two provides a way to check whether the cost of equity for RIIO-2 is at an appropriate level relative to the forward looking cost of debt for energy networks.

As set out in section 4 of Oxera Report 1, Oxera submitted evidence as part of the ENA's response to Ofgem's RIIO-2 SSMD in March 2019 on how its proposed allowance on the cost of equity compared with the pricing of risk for these companies in the debt markets[557].

In their updated report (Oxera report 4), they show that:

- The benchmarks for ARP−DRP can be employed not only as a cross-check to cost of equity, but also to obtain conservative estimates of the allowed WACC, because of the downward bias in asset beta estimation.
- After adequately addressing Ofgem's concerns set out in the RIIO−2 SSMD, their findings reveal more information to support the conclusion that Ofgem's RIIO−2 cost of equity allowances in the Draft Determination falls below that implied by (i) contemporaneous market evidence for the cost of debt and the risk-free rate; and (ii) a mixture of contemporaneous market evidence and regulatory precedent on the asset beta and the TMR. This conclusion is based on the finding that the ARP−DRP differential implied by Ofgem's allowances is low compared to those implied by the traded yields of energy bonds over the six-month period preceding the RIIO−2 Draft Determination.
- Their updated analysis, incorporating various methodological improvements, finds that the ARP−DRP differentials implied by past regulatory allowances for energy companies (i.e. RIIO−1, NIE RP5 and RP6) were broadly in line with those implied by contemporaneous market evidence around the corresponding determinations.

Finally, Oxera note that Ofgem's Draft Determinations contain a large number of cross-checks meant to support a lower CoE estimated by Oxera in this report. Notwithstanding our concerns with the robustness of these cross-checks, as

[557] Oxera (2019), 'Risk premium on assets relative to debt', 25 March

detailed in the Ofgem Cross Checks Section above, none of these cross-checks is directly comparable with Ofgem's CAPM analysis. In contrast, the comparison Oxera have undertaken between the allowed return on assets and the pricing of risk within the debt market is a test of internal consistency between different elements of the capital structure for the same company. A cross-check that is directly comparable to the cost of equity for companies regulated under RIIO-2 should be given more weight.

Type 4 – New evidence presented on the Asset Risk vs Debt Risk Premium check after feedback from Ofgem

Further cross checks - Broker Coverage of Listed Equity

The recent estimates of RIIO-2 cost of equity by finance practitioners show that Ofgem's allowed cost of equity is unreasonably low, for example;

- **Investec (July 2020)** estimates a cost of equity of 4.8% vs Ofgem's allowed return of 4.3% (pre-DD), which indicates they view that equity returns should be higher than the allowance. They also discuss the relative risk of water vs energy, commenting that "our view that there are greater risks and challenges in energy that would support a higher allowed return than in water."
- **In its analyst report on SSE (Jefferies Feb 2020)** commented that, "We see Ofgem's current view of 4.3% cost of equity as significantly below the relevant regulatory benchmarks such as Openreach (5.3-5.9%) and Air Traffic Control (6.0%). Given the scale of investment required for the decarbonisation of energy networks, we see these sectors as more comparable to energy networks, as opposed to the UK water networks."
- **Barclays (August 2020)** estimates a cost of equity of 4.8% vs Ofgem's allowed equity return of 3.95%, which is a sizable difference.
- **HSBC April 2020 report**, HSBC increased its equity beta estimate for SSE from 0.82 to 0.90 and it has maintained this in its July report. This indicates SSE faces higher systematic risk and is consistent with the increase in betas seen since the start of the Covid-19 pandemic earlier this year.

Type 4 – New evidence presented on how estimates of RIIO-2 cost of equity by finance practitioners show that Ofgem's allowed cost of equity is unreasonably low.

Further cross checks - Regulatory Cost of Capital and Consumer Welfare

Although keeping customer bills as low as possible is a vitally important part of the price control process SGN believe that Ofgem's draft determination is unduly focused on the reduction of cost of capital to minimise customers' bills at the expense of customer welfare. We appreciate it is a fine balance between the risk of potentially overcharging customers and the risk of the company not being able to carry out its investment programme.

As highlighted in section 5.1 of Oxera Report 1 the regulator's objective is to choose the WACC point estimate to balance the potential loss in welfare from underinvestment against the loss in welfare from setting prices higher than necessary to incentivise investment. The regulator has to take this decision in the context of uncertainty about the underlying WACC and cost of equity. We believe that Ofgem are setting the cost of capital too low and thus risking the future significant investment required in UK energy networks.

Type 4 – New evidence presented on how Ofgem's spot estimate of WACC is unduly risking loss of welfare from underinvestment, showing that the DD cost of equity estimate is too low

Further cross checks - Multiple Methodology Change Sense Check

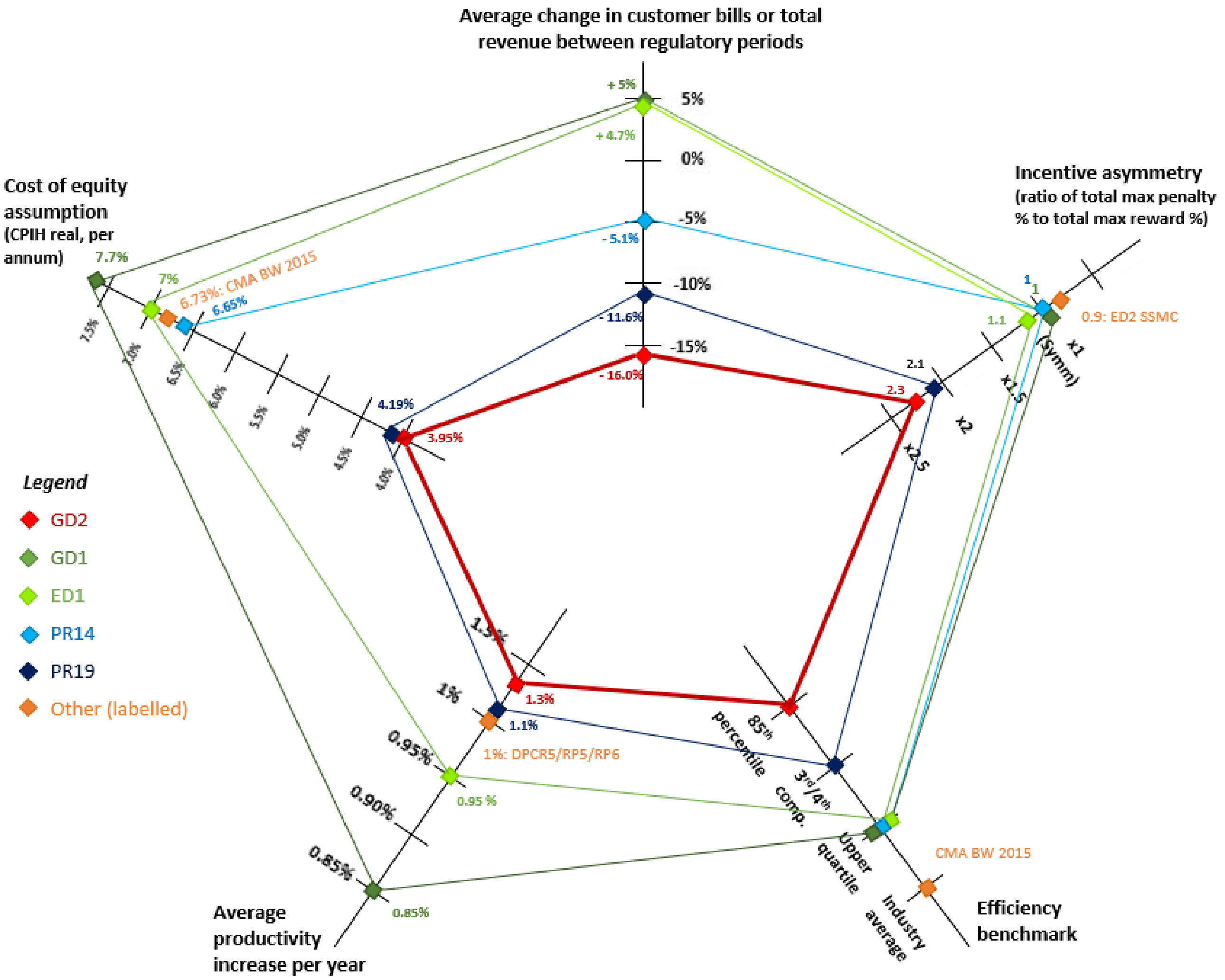
SGN note, as set out in the Executive Summary of Oxera Report 1, that Ofgem have made all the following fundamental changes to the cost of equity in one price control which are responsible for the majority of the downward movement in cost of equity;

- restating the historical total market return (TMR) based on an experimental index for historical CPI, which results in a lower estimated TMR;
- increasing the weight on the geometric average historical return, thereby moving further away from the correct (Cooper) estimator, resulting in a lower TMR;

- moving to spot yields on government bonds, which lowers the estimated RFR
- using a debt beta of 0.125 where previously Ofgem used zero, which artificially deflates the notional equity beta;
- reducing the allowed return below the estimate of the CoE.

Notwithstanding the fundamental flaws we have highlighted to these changes in our responses to FQ4-FQ9, it has to be questioned why an unprecedented number of significant methodological changes are being made in just one price control. Furthermore, they all drive the cost of equity downwards. So, it needs to be considered, for confidence in the regulatory regime and stability, whether, even if deemed robust, whether these should all be introduced at once. In order to retain a significant degree of investor confidence in the regulatory regime if these methodological changes do all need to be introduced, surely they should be phased in over a few price controls.

These concerns with multiple methodology changes being introduced, all driving down the cost of equity, are only magnified when looking at the risk return balance for RIIO-2 versus other comparative price controls;



Type 4 – New evidence presented on the sheer number of proposed fundamental changes to the cost of equity in one price control, all in a downward direction. This cross-check highlights, notwithstanding the fundamental flaws in these changes highlighted in response to FQs4-9, that these changes need to be phased in over a few price controls for stability and to maintain a degree of confidence in the regulatory regime. This again highlights that the DD cost of equity estimate is too low

6.3.7 Step-3: Ex-post adjustment

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?

As detailed in response to FQs 4-8, we believe there are fundamental flaws with the methodology used in Step 1 (CAPM) and Step 2 (Market Cross Check) of the allowed returns on equity assessment. Also, we fundamentally disagree with the deduction of an outperformance wedge in Step 3, as set out in our responses to FQ10-11.

Furthermore, looking at Ofgem's points in paras 3.170 and 3.171 of the DD Finance Annex, SGN firmly believe GDNs are significantly riskier than water networks and thus should have a higher equity beta and cost of equity, as evidenced in our response to FQ5. Therefore, the comparisons drawn with SVT and UU are not relevant due to this risk differential. Also, we detailed in our response to FQ6 the factors as to why RIIO-2 is higher risk than RIIO-1.

Notwithstanding these important points we would add;

- a 10 year asset beta estimation window does not seem representative sampling of the historical asset beta data available
- the PR19 Final Determination had an equity beta of 0.71 so extreme care needs to be taken when inferring a lower equity beta from SVT and UU equity betas,
- once the issues of how Ofgem has applied the MM theorem have been addressed (see section 'Ofgem's Proposed Cross Checks' section above) Ofgem's concerns over an upward sloping WACC are alleviated.
- that we have detailed in the 'Ofgem's Proposed Cross Checks' section above our significant concerns with Ofgem's Investment Manager's forecast

Type 1 - Factual or computational errors in the in the round assessment of the allowed return on equity.

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?

As set out in our response to the cost efficiency annex we believe that Ofgem have applied cost assessment tools such as the 85th percentile for benchmarking and extreme ongoing efficiency assumptions that go beyond regulatory precedent. So, whilst the P50 risk analysis conducted by PWC (in PWC report 1) and our cost efficiency response highlights the need to address the £340m Totex shortfall we believe this creates, this also demonstrates there is no justification for an outperformance wedge given the asymmetry of the package.

Notwithstanding our significant objections to this wedge being applied in the first place, we highlight below how the application of the outperformance wedge would damage incentive properties of the price control, our concerns over the construction of the Totex outperformance database and how Ofgem's approach materially underestimates the scale of the changes Ofgem are proposing in RIIO-2

Ofgem decided in its Sector Specific Methodology Decision that it would adjust the baseline return downward by a wedge to account for the expected outperformance in RIIO2.[558] Ofgem seems to have based its proposal on the recommendation from the UKRN paper where a subset of the authors (Mason, Pickford and Wright) concluded that regulators should set the allowed return taking into account any anticipated outperformance such that the expected rate of return is equal to the WACC.[559]

In their original report[560], Frontier examined Ofgem's motivation and assumptions behind making an adjustment to baseline returns to take account of anticipated outperformance. They disagree strongly with MPW's recommendation because their model (and consequently Ofgem's proposal based on their model) is flawed, they provide no guide on how to implement their proposal, and their assessment of wider impacts is non-existent.

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558 Ofgem (2019), RIIO-2 Sector Specific Methodology Decision Annex: Finance, para 3.300
559 Wrights, Burns, Mason, Pickford, 2018, Estimating the cost of capital for implementation of price controls by UK Regulators, UKRN
560 Frontier (2019) 'Adjusting Baseline returns For Anticipated Outperformance'

Frontier also argued that historical evidence, considered over a suitable time horizon, shows that outperformance by energy networks has varied widely by sector and that regulation is not a one-way bet. They have shown in their report that the fact that RIIO-1 may have led to higher than expected returns for some companies does not mean that price controls in general cannot be calibrated fairly and symmetrically.

Ofgem seems to generally lack confidence that price control calibrations could be symmetrically and believe that investors are likely to base their expectations for RIIO-2 based on probabilities informed by previous scenarios.[561]

Recent historical levels of outperformance are not representative of potential outperformance in RIIO-2 because the changes that Ofgem is considering implementing for RIIO-2 would curtail markedly the scope for outperformance. We note that Ofgem seems to be the only regulator that doubts its own ability to set a symmetric price control, to such an extent that mechanisms that serve to curb incentives (such as the adjustment on baseline returns and RAMs) are proposed purely for the purpose to avoid excessive returns in the next price control. We observe that other UK regulators such as Ofwat and the CMA (which is determining the price control for NERL) do not seem to believe that there is a need to put in such mechanisms at the cost of curbing incentives.

Ofgem asserts that regulation is a repeated game and the difference between RIIO2 and RIIO1 is not necessarily larger than the difference between RIIO1 and pre-RIIO1 period.[562] It is not clear exactly to which differences Ofgem refers, but there are a number of one-off factors that contributed to the outperformance in RIIO1 that will not be present in RIIO2.

Ofgem seeks to claim that it would be impossible to address its concerns through direct recalibration of the areas where it considers outperformance will inevitably arise.[563] For Ofgem to justify the use of the proposed blanket adjustment it would need to be able to explain why the results achieved by Ofgem itself in the past and in the water sector are no longer possible.

Unintended incentive effects of outperformance wedge

Frontier's 2019 report on aiming up and the use of the outperformance wedge[564] explores thoroughly the unintended consequences that would arise from Ofgem's proposed approach. They outlined in detail how Ofgem's proposal would:

- weaken the clarity over how the price control is calibrated.
- erode investor confidence and increase investor risk;
- weaken incentives for efficiency and innovation;
- distort managerial incentives to invest; and

We set out below Ofgem's critique of these points and Frontier's response to these points, which are further detailed in Section 3.1 of Frontier report 1;

- **Loss of Clarity:** In the DD Ofgem has invited Frontier to provide more explanation on the point on the lack of clarity. The lack of clarity stems from the fact that, if Ofgem's proposed deduction is adopted, there will now be a number within the price control that represents Ofgem's subjective judgement of the extent to which it has failed to set other aspects of the price control (including financing, cost allowances, ODIs, etc.) appropriately. This clouds the judgement of the future calibration of such price control parts and can potentially frustrate the proper use of focused appeal rights. It can also hinder proper scrutiny and interpretation of targets by all stakeholders.
- **Justified versus unjustified returns and enduring incentive system:** Ofgem also countered that Frontier's depiction of incentives (and thus productive efficiency) does not distinguish between justified and unjustified returns. It is not clear to us what constitutes justified or unjustified returns in Ofgem's view. If by unjustified return Ofgem means any realised return in excess of the estimated cost of equity, this would amount to a retrospective introspection inconsistent with the principles of incentive regulation.

  We agree with Ofgem that the incentive system must not have a systematic bias if it is to be enduring. We would also agree with Ofgem that systematic over-remuneration is not necessary to maintain an adequate level of investment and could indeed lead to challenges to the legitimacy of the system. However, as explained in Frontier's original report, the solution to any suspected systematic over-remuneration is to fix the root cause of it. In the case of RIIO-1,

561 Ofgem (2019), RIIO-2 Sector Specific Methodology Decision Annex: Finance, paras 3.284 and 3.285
562 Ofgem (2019), RIIO-2 Sector Specific Methodology Decision Annex: Finance, para 3.298
563 Ofgem (2018), RIIO-2 Sector Specific Methodology Consultation Annex: Finance, para 3.164
564 Frontier (2019) 'Adjusting Baseline returns For Anticipated Outperformance'

the root cause of most outperformance was Ofgem's failure to set appropriate targets in certain key areas. This had little to do with the assessment of the cost of equity or allowed returns and Ofgem should not conflate its analysis of what is now the reasonable level of returns with these past failures to set reasonable targets. The allowed return is simply not the appropriate place to address the issue.

- **Clarifying again the harm to incentives** Ofgem's reaction to Frontier's argument regarding the potential loss of incentives focuses on the incentives for the investors to continue to invest, by stating that as long as the allowed return coupled with the incentive payments would meet the cost of capital in expectation, investors would continue to invest. However, this does not address Frontier's core concern. By loss of incentives, they mean the incentives to innovate and improve cost efficiency, which comes from the fact companies are allowed to create extra financial gains as a result of operation performance.

  Ofgem only briefly addresses the question of how the outperformance wedge may harm incentives in its draft determination, noting that it does not face a 'binary choice' between applying a wedge and incentives. However, at no point does it present any kind of appraisal of:

  - whether its policy will harm incentives;
  - if so, by how much; and
  - what the potential effect on company behaviour, outcomes and overall consumer welfare may be.

  Ofgem's proposal unambiguously forms a link between outperformance in one period and a negative downward adjustment to allowed returns in some future review. This must dampen incentives to make future efficiency gains, which have been the backbone of the productivity gains achieved in the energy sector in the past decades.

- **Ofgem underestimates the importance of productivity gains in the energy sector** We have outlined above our profound concern in relation to the negative incentive effects that could arise from Ofgem's proposal, and the behavioural change that this could trigger. The end result of this could be a marked deterioration in the vigour with which companies now pursue operational and service improvement. This can only slow the productivity delivered by the sector.

Ofgem's position appears to be that there is little to lose by harming these incentives. In contrast, Frontier set out in section 3.1.4 of Frontier report 1 how there is much to lose to the direct detriment of customers by harming these incentive properties, as summarised below;

Size of the productivity gain at risk

To measure the scale of the productivity gains at risk based on the DD proposals , Frontier use Ofgem's DD ongoing efficiency challenge at 1.2% per year for capex and repex and 1.4% per year for opex (notwithstanding that SGN believe these assumptions are too high) and Frontier use this to put into context the potential losses that could result from under-remuneration going forward. This is particularly important as the UK energy sector gears up to achieve the UK's 2050 carbon neutral target.

Sacrificing even a fraction of long-term productivity gains for short-term savings could result in large cost increases across the sector, making any erosion of the incentive regime (such as the 25 bps outperformance adjustment) likely to do more harm than good in the long run. The key findings of Frontier's analysis are;

- In a reasonably conservative scenario where 10% of the expected productivity gains in the energy sector are removed by the adjustment for anticipated outperformance, the annual loss in cost savings due to compromised productivity gains would outweigh the gain (from the 25 bps deduction) by 2027/28. Under other scenarios with further productivity losses, the catch up point would be much sooner with the annual loss in cost savings outweighing the gains (from the 25 bps deduction) by 2021/22 if 25% of the net productivity gains are removed and by 2020/21 if 50% of gains are removed.

- Discounting the above cash flows over the next 50 years and considering the net present value (NPV), Frontier find that if the annual net productivity gains shown in the past decades is eroded by anything more than around 3% due to changes in the strength of the incentives regime brought about by the 25 bps outperformance-based reduction on equity returns, the present value of the productivity losses to the sector would outweigh the present value of the gains for the customers.

The results from this analysis show that, although there is uncertainty regarding the scale of the impact on efficiency gains, the effect of a loss in even a small proportion of the expected efficiency gains going forward would cause enormous consumer detriments. The role of the regulator is to create a framework that encourages the companies to keep driving out productivity improvements every year. Over time, given the scale of the GB energy networks, these marginal gains lead to huge societal savings.

We consider that it would be prudent for Ofgem to make its own assessment on the potential harm that could be caused by the proposed outperformance adjustment to baseline returns, before it presses ahead as the only regulator to implement this mechanism. We have not yet seen satisfactory assessment from Ofgem to suggest that the pros and cons of this mechanism have been appropriately considered.

Type 1 - Factual or computational errors. Ofgem's outperformance wedge proposal fails to take into account a number of fundamental unintended incentive effects it would

Type 4 – New evidence presented on factors Ofgem haven't considered when implementing an outperformance wedge: loss of clarity of how price controls are calibrated, the need to distinguish between justified and unjustified returns, the harm to incentives to innovate and improve cost efficiency and the consequential productivity gains that will be lost.

Justification for the quantum of the proposed outperformance wedge

The fact that Ofgem previously considered that the evidence pointed to a wedge of at least 50 bps, whereas it now considers the evidence points to a wedge of 25 bps, may say something about the difficulty of calibrating a wedge of this kind, notwithstanding our fundamental concern around the concept of an outperformance wedge highlighted above.

In supporting its wedge, Ofgem relies on a range of new evidence, presented for the first time in its draft determination which are critiqued in detail below (parts a-c of FQ10);

- A review of historical cost outperformance across many price controls and sectors (contained in the "AR-ER database.xlsx" file);
- An analysis of what performance in RIIO-1 would have been under the RIIO-2 framework (contained in the "Residual outperformance.xlsx" file); and
- Ofgem's assessment of what can be properly inferred from prevailing MARs and past transaction premia (contained in the "Simple MAR application model.xlsx" file).

FQ 10a. "AR-ER database.xlsx"

We have the following significant concerns with Ofgem's totex outperformance database;

- **Standard of Data**. Ofgem's database of cost performance across multiple sectors and over time has a number of significant flaws, as highlighted in section 4.1.2 of Frontier report.
- **Recent history is no reliable guide.** Ofgem's approach here is the presumption that it is safe to infer something sensible about future outperformance from past outperformance. We do not believe that such an inference is reasonable or logical, especially given the scale of the changes from RIIO-1 to RIIO-2, which has seen a fundamental shift from incentive based regulation towards rate of return regulation.

  Furthermore, the philosophy and methodologies that underpin early energy network price controls were indeed far removed from RIIO-1. Benchmarking was comparatively limited and there was no heavy focus on ensuring that costs and revenues would track one another closely during a price control. The focus was entirely on setting a broadly reasonable "fixed target" alongside very strong incentives (particularly on opex) that would provide strong inducement for the only relatively recently privatised firms to pursue and reveal efficiencies as aggressively as possible
- **Ancient history is totally irrelevant.** It is simply not credible to suggest that the very high levels of outperformance achieved during early price controls would provide a sound basis for drawing inferences about expected performance during RIIO-2.

  The notion that an investor today appraising the future prospects of an energy network would somehow include outperformance of this magnitude within its reasonable distribution of possible outcomes (as is suggested by Ofgem in paragraph 3.127) is not realistic. Frontier note in passing that simply removing DPCR1 to 3 and PCR2002 reduces the mean observed outperformance to 3.7%.

- **The Relevance of Data from Other Sectors.** The inclusion of airports, air traffic control and the water sector in an analysis that is intended to support inferences about what the networks may be able to achieve in future is clearly distinctly debateable. While there are some high level similarities in the overall price control frameworks, there are also important differences in the way regulation is done and the underlying costs and cost structures of these different businesses operating in different sectors. To illustrate, Heathrow has an average revenue form of price control so there is a need to control for volumes. It seems that this has not been done, and hence it is not clear that the data for airports is reliable, even if we were to believe that it is otherwise comparable.
- **Ofgem's sample size is effectively much smaller than it claims.** Ofgem claim that the database has 943 observations, and this reduces to 210 as it presents the results on a price control basis. However, this heavily rests on the assumption that each individual licensee should be accounted for individually in this analysis. In actual fact, a very significant proportion of the apparent outperformance from the RIIO-1 price controls was due to forecasting errors and Ofgem's decisions on various price control elements. Therefore, the outperformance across companies within the same price control is closely related, not at all statistically independent, meaning that data on each individual company cannot really be considered to bring much additional information to the sample. As a result, to suggest that Ofgem has 210 let alone 943 observations is misleading and overstates the informational quality of the sample.

Added to this, as we have explained above, we have material concerns with the inclusion of ancient price controls in this analysis, as they are completely irrelevant in terms of assessing the likely levels of performance at RIIO-2. The removal of these price controls from the dataset would further reduce the sample size. Overall, the number of observations that Ofgem claims to have is significantly misleading as it counts each company individually and includes price controls that are not relevant. As a result, there is no validity to the argument that this database has a large sample and is somehow statistically robust.

Summary views on Ofgem's historical totex database

In conclusion the database is clearly intended to provide broad narrative support for the points that Ofgem, as far as we understand it, relies on in concluding that an outperformance wedge is necessary. These arguments are:

- that regulation is "one way bet" in which companies materially outperform in expectation;
- that the proposed 25 bps wedge is, however one considers it, small compared to the outperformance that must be expected given historical outperformance; and
- that a broadly symmetric calibration is impossible to achieve, or at least sufficiently improbable, and hence an outperformance wedge is the only viable alternative to protect customers.

In fact, the database properly considered does not support any of these assertions;

- The overall conclusion on measured outperformance is very materially influenced by ancient history that is wholly irrelevant. Correcting for this alone already reduces average observed outperformance from 7% to 3.7%.
- That 3.7% is then based on more recent price controls, but even this is a wholly irrelevant number given the raft of changes that Ofgem now proposes to introduce at RIIO-2, compared to earlier price controls.

Far from confirming that setting a symmetric price control is impossible, Frontier's analysis provides numerous examples of broadly symmetric price controls being put in place, with relatively small levels of overall sector outperformance. We note that Ofgem has set broadly symmetric price controls before.

Type 1 - Factual or computational errors. We have a number of significant concerns with Ofgem's totex outperformance database and how its being used by Ofgem.

Type 4 – New evidence presented on the standard of data, how recent history is not a reliable guide and past data is irrelevant, why there shouldn't be emphasis on data from other sectors and why Ofgem's sample size is effectively much smaller than it claims

FQ 10b. "Residual outperformance.xlsx"

As detailed in Frontier report 1, section 4.2.2, Ofgem states that it has identified an alternative approach for estimating the likely levels of outperformance at RIIO-2 by restating the RIIO-1 historical performance on a RIIO-2 basis.[565] To do this, Ofgem has gathered data on RIIO-1 outperformance across all energy network operators and has made various

565 Ofgem RIIO-2 Draft Determination – Finance Annex, para 3.129

adjustments to the underlying data. The adjustments are intended to reflect the differences between the regulatory instruments at RIIO-1 and RIIO-2, hence showing what the RIIO-1 outperformance would have been if the RIIO-2 framework applied instead. Ofgem concludes that the adjusted results “are more informative for RIIO-2, given the greater consistency with the RIIO-2 framework” and that “this analysis generally supports expected outperformance levels above 0.25% for RIIO-2.[566] Frontier have reviewed Ofgem’s approach and have identified the following significant methodological issues and errors in section 4.2.2. of their report, which mean that Ofgem’s approach materially underestimates the scale of changes it has made for RIIO-2 and when taken into account mean that there is limited opportunity for outperformance (if any at all) under RIIO-2;

- **Ofgem adjusts for but downplays the significant impact that RPEs has on performance.** Notwithstanding our concerns over Ofgem’s RPE indices used in GD1 and proposed for GD2, Frontier calculate that GD1 totex allowances for the GDNs would have been 5% lower if RPE allowances had been indexed each year rather than being set ex-ante based on forecast price changes. Given that average totex outperformance in this sector was 11.8% (before applying any sharing factors), this implies that RPEs account for almost half of the observed totex outperformance.

Additionally, Frontier’s analysis also shows that the forecast RPEs for electricity distribution are very close to the actual RPEs (but if anything slightly higher than the actual RPEs). This example shows that it is possible to set allowances symmetrically.

- **Ofgem’s calculation error overstates outperformance for RIIO-GT1.** Frontier have identified an error in the calculation of GT1 totex outperformance that results in the outperformance after RPE adjustment being overestimated. Ofgem’s calculation suggests that the RPE adjustment increases the GT1 totex performance from -1.0% to -0.4% of RoRE, but it actually decreases to -1.5%
- **Ofgem fails to take account of all of the relevant differences between RIIO-1 and RIIO-2.** In addition to the calculation error that we explain above, section 4.2.2 of Frontier’s report details how Ofgem’s analysis fails to take account of all the differences between RIIO-1 and RIIO-2. In doing so, Ofgem’s analysis is incomplete and consequently misleading;
    - **PCDs:** These are specific carefully prescribed deliverables against which specific funding has been allocated. The intention is to put in place a mechanism whereby revenues are clawed back if the specified output is not delivered (either entirely or partially). The nature of individual PCDs are bespoke, and so the way they are assessed will need to vary from PCD to PCD. As described by Ofgem, PCDs are subject to project-specific incentives. Some PCDs will have allowances recovered through a formulaic method, while others will be subject to an ex-post review from Ofgem. However, Frontier understand that Ofgem’s broad intention behind introducing PCDs is to restrict any totex outperformance in the event of non-delivery or late-delivery of specific projects, or changes in scope/spec of works compared to what was anticipated when the price control was set.[567] Given this, Frontier consider this means a potential source of totex outperformance in RIIO-1 has now been removed for RIIO-2. Given the proposed nature of the clawback mechanisms and the use of ex post appraisal, we consider it is sensible to assume that expected outperformance is zero on PCD-totex. PCDs will be applied to around 25%-45% of each company’s total expenditure.[568] Ofgem has made no adjustment to take account of the widespread use of PCDs (and other related UMs that can be expected to operate in a similar way).
    - **NARMS:** the Network Asset Risk Metric (NARM) will be similar to its RIIO-1 predecessor the Network Output Methodology (NOM) in terms of having a target for monetised value of risk removed over a price control. But NARMs will differ from the RIIO-1 methodology in a number of other key aspects, as detailed in section 4.2.2. of Frontier report 1;
        a. Linking more costs specifically to NARMS outputs than was the case for NOMS in RIIO-1
        b. Networks will be set a target for the ratio of baseline NARM-allocated totex over NARM risk removed. This target is referred to as the Unit Cost of Risk Benefit (UCR). Any outturn deviations from the UCR target will be closely scrutinised by Ofgem through an ex post review. Clearly, deviations from the UCR target could be driven by:
            - a change in expenditure vs. what was allowed for in the UCR numerator; and/or

566 Ofgem RIIO-2 Draft Determination – Finance Annex, paras 3.131 and 3.132
567 RIIO-2 DD core document, paragraph 4.8-4.10
568 This is based on data we have received from the companies and also through the Ofgem license models.

  - a change in risk benefit delivered vs. what was targeted in the UCR denominator.

c. Ofgem says it will reward cost reductions with the full TIM sharing factor if the companies provide evidence in an ex-post close out Performance Report that:

  - the cost reductions represent "genuine efficiencies" and
  - the cost reductions "have not been offset by higher costs elsewhere".

However, underspends that don't pass these 2 tests will not be subject to the same sharing factor. While Ofgem is consulting on what level to set the DAF, Frontier evidence that its very clear that Ofgem intends a very material reduction in the effective sharing factor, for any underspends which do not meet the two tests above.

d. In contrast, for any cost overspends, the full TIM sharing factor will be applied. This means there is no equivalent test for "genuine" overspend that would offer equivalent downside protection for the companies

e. For over-delivery or under-delivery against the NARM risk benefit target, Ofgem will assess whether this is "justified" or "unjustified" and accordingly impose different treatments, notably:

  - Any justified over-delivery or under-delivery is effectively allowed in full, only if the unit cost of this delivery is in line with the ex ante allowance.
  - Any unjustified under-delivery receives a penalty of 2.5% of the resulting change in allowances.
  - Any unjustified over-delivery will have associated increase in costs disallowed, effectively receiving a penalty based on the full TIM sharing factor.

f. A number of new restrictions have also been placed on exactly how networks can deliver their risk output. In particular, companies will have new restrictions around the extent to which they can 'trade' risk reduction outputs across assets in different categories, meaning companies will no longer be able to beat totex allowances by changing the work mix (while delivering the target risk benefit).

As evidenced in section 4.2.2 of Frontier report 1, in attempting to impose the constraints above, Ofgem has proposed a model that relies almost entirely on judgements made by the regulator ex post. Specifically, companies will now be significantly exposed to the decision that Ofgem makes ex post on whether costs savings were "genuine"; and on whether any departures from the risk target were "justified" or "un-justified". Importantly, Ofgem's underlying principle seems to be that companies must bear the burden of proof in these ex-post assessments – in other words, Ofgem's default position will be that deviations are unjustified, and it is up to the companies to convince Ofgem otherwise. At the same time, the NARM framework imposes a significantly skewed balance of risk towards the downside, conditional on the exercise of Ofgem's ex post discretion.

- **Productivity:** At RIIO-1, Ofgem set the annual productivity challenge of 1% for opex and 0.7% for repex and capex. For RIIO-2 Ofgem has set the much tougher annual challenges of 1.4% for opex and 1.2% for repex and capex, despite the fact that the evidence for such rapid productivity improvement seems in many regards weaker now than it did at RIIO-1 (SGN do not agree with these assumptions as set out in the cost efficiency section of this report). As a result of its assumptions with respect to productivity, Ofgem will set tougher cost allowances for RIIO-2 than it did at RIIO-1. This will reduce the likelihood that companies outperform. This toughening of calibration should be reflected in Ofgem's restatement analysis, but it has not been.
- **Benchmarking approach**: At RIIO-1 Ofgem used the upper quartile as its benchmark in the cost assessment for the GDNs but at RIIO-2 Ofgem has provisionally set the tougher benchmark of the 85th percentile. While SGN object to this approach in principle, if it is maintained, this will set tougher cost allowances and reduce the scope for companies to outperform. As a result, this change does need to be reflected in the analysis. It is Frontier's understanding that there has also been a marked toughening in the approach to benchmarking within the transmission sector, which again has not been accounted for, but would again provide further evidence that RIIO-1 levels of outperformance will not be repeated at RIIO-2. Finally

  the scope of application of the benchmarking analysis has been expanded in RIIO-GD2. In both RIIO-GD1 and RIIO-GD2 (and in benchmarking more generally), Ofgem removes certain costs pre-benchmarking on the basis that they should be normalised out, for example regional wage differentials and non-regressed costs such as streetworks or SIUs, but in RIIO-2 Ofgem applies the benchmark efficiency score to these.

- **IQI and BPI:** the IQI has been removed for RIIO-2 and replaced by the BPI. The IQI had three components;
  - it affected the size of the sharing factor;
  - it included an upfront additional reward / penalty;
  - it also relied on interpolation to set final allowances, as a weighted average of 75% modelled costs and 25% submitted costs.

  Ofgem states that it considers the impact of these two schemes on returns "may be similar". For this reason, Ofgem does not quantify the change of removing the IQI and introducing the BPI. In our view this is a flawed assumption for the following reasons.

  - Ofgem appears to be comparing the impact of only the additional reward/penalty aspect of the IQI with the BPI and concluding that these may be similar, and therefore it does not need to quantify this change.

    However, this is simply not the case. Some companies have received very substantial penalties under the BPI and as a result, this change needs to be accounted for much more completely.
  - Ofgem does not appear to recognise the need to account for the removal of the IQI interpolation at RIIO-2. IQI interpolation had a material impact on final allowances at RIIO-1, and nothing at RIIO-2 could be considered to be equivalent to this.
- **Fast Tracking**: At RIIO-1, the IQI did not apply to companies that were fast-tracked. But fast-tracked companies received their submitted costs, and an upfront reward equal to 2.5% of totex allowances. The opportunity to be fast-tracked has been removed, and with it the chance to earn this reward. The fast-track reward should therefore be removed from Ofgem's analysis, but it has not been.
- **Changes to output incentives:** Ofgem has changed some detailed aspects of various output incentives, and also removed some output incentives entirely. For example, the NTS Exit Capacity incentive has been removed from the GD price control. While Ofgem has also added in a new incentive to the GD control, the unplanned interruptions incentive, this is a penalty only incentive.[569] Overall therefore the potential for outperformance on output incentives in the GD sector has been reduced. More generally, it is clear that Ofgem has significantly toughened its approach to ODI calibration in very many areas across all price controls, and the effect on potential outperformance is clear. We believe Ofgem is therefore wrong to take no account of these changes in its analysis.

Impact of Taking into Account All the Quantifiable Differences Between RIIO-1 and RIIO-2

While Ofgem suggests that the aspects that it has ignored in its analysis are irrelevant or immaterial, this is clearly wrong. Ofgem's set of adjustments in restating RIIO-1 on a RIIO-2 basis are clearly incomplete. The conclusions it draws from its analysis are therefore incorrect and misleading.

Ofgem's failure to adjust for all relevant differences between RIIO-1 and RIIO-2 lead it to overstate markedly the level of likely RIIO-2 performance. To quantify how much Ofgem's analysis fails to overstate RIIO-2 outperformance, Frontier have undertaken a revision of Ofgem's restatement of RIIO-1 to more completely and robustly re-present the historical returns under the proposed RIIO-2 framework, taking into account the factors that could be quantified in the section 'Ofgem fails to take account of all of the relevant differences between RIIO-1 and RIIO-2' above

The steps Frontier took to represent this work are set out in section 4.2.3 of Frontier report 1. Figure 7 in section 4.2.3 of Frontier report 1 shows that accounting for the more thorough restatement of RIIO-1 undertaken by Frontier, leaves no totex outperformance and incentive performance for GDNs in GD2. This therefore fundamentally questions the proposed implementation of an outperformance wedge, notwithstanding the points made above regarding the significant unintended consequences on incentivisation that introducing such a measure would introduce.

Furthermore, Frontier have not been able to quantify the impacts of all the changes between the RIIO-1 and RIIO-2 regulatory frameworks set out in section 3 above. As detailed in section 4.2.3 of Frontier report 1 there are unquantifiable elements of the following changes that Frontier show on a qualitative basis would have had the effect of reducing outperformance even further;

- PCDs

569 Ofgem RIIO-2 Draft Determinations – Gas Distribution Annex, p. 33

- NARMs
- Further benchmarking changes
- Fast Tracking
- Changes to output incentives

Type 1 - Factual or computational errors. Ofgem have made a number of significant errors when restating RIIO-1 historical returns in a RIIO-2 context.

Type 4 – New evidence presented includes how Ofgem have downplayed the impact of RPEs and how Ofgem have failed to take into account all the relevant differences between RIIO-1 and RIIO-2.

FQ 10c. "Simple MAR application model.xlsx"

As detailed in section 4.3 of Frontier's report, Ofgem's reliance on the MAR to calibrate the overall level of an outperformance wedge is misguided. This is because:

- using volatile market information to fine tune allowed returns has the potential to introduce this volatility into regulatory determinations, something that is inconsistent with the long run nature of these businesses and their very long term planning horizons;
- most market observers would accept that equity prices can move in ways that are not perfectly correlated with the fundamentals of valuation, hence MAR evidence is difficult to interpret and must be treated with considerable caution;
- Ofgem relies extensively on evidence from the three listed water companies, which we do not consider to be a reliable basis to draw inferences for energy networks;
- the transaction premia cited by Ofgem are out of date;
- if Ofgem were capable of measuring energy network MARs and used these to fine tune allowed returns, then this is likely to lead Ofgem to over-correct at RIIO-2 (and at future price controls) for past outperformance;
- introducing a MAR cross check has the potential to further weaken the incentives for companies to outperform, for the same reasons as does applying an outperformance wedge; and
- the process of fine tuning of allowed returns introduces another source of arbitrary regulatory judgement with the potential for the resulting regulatory risk to be asymmetric, as regulators may be happy to adjust allowed returns down but far less happy about adjusting them up.
- Ofgem has made a raft of changes elsewhere to address excess returns plus it has already introduced a MAR check of its cost of Equity. A MAR adjustment, where those MARs are primarily derived from other sectors and out of date transaction premia will not embody the many important proposed changes in regulatory design. Hence there is a clear danger that Ofgem ends up correcting aspects of the RIIO-1 price controls that led to outperformance directly at source, and also introducing an additional wedge on the cost of equity to correct for those same errors.

Furthermore, the MARs of water companies ultimately depend on the calibration of Ofwat's regulatory regime and companies' own operational risks. Using water company MARs to adjust returns for energy networks would create the risk of adjusting returns for energy networks to take account of factors that have absolutely no relevance to that sector.

Furthermore, the three listed water companies may not even be particularly representative of the performance of the wider water sector, adding a further complication:

- The three listed companies happen to be the only three companies to receive enhanced status from Ofwat. These companies may well face price controls with more upside opportunity than exists for the sector more widely.

- these three companies may also face other advantageous circumstances, e.g. according to Ofwat's most recent performance reports all three appear to have average costs of debt comfortably below Ofwat allowances and below industry peers.[570]

We therefore find no merit in Ofgem's use of water company evidence to calibrate energy network MARs.

We also note that Ofgem is selecting the information that it relies on in a way that is internally inconsistent and likely to lead to biased (downwards) outcomes. It is happy to rely on MAR evidence here that is evidently volatile over time and derived from a decomposition of the business activities of the various listed entities analysed by CEPA that requires a multitude of assumptions. This evidence Ofgem decides is sufficient to support a downward adjustment in allowed returns. Yet within the same consultation Ofgem, supported by CEPA, concludes that no weight should be placed on beta decomposition analysis, as it is volatile and depends on too many assumptions. Hence Ofgem decides that a lower range for allowed betas is justified. We do not consider that there is a reasonable justification for this arbitrary difference in approach across different aspects of its decision.

Type 1 - Factual or computational errors. Ofgem's reliance on Market Asset Ratios to calibrate allowed returns is misguided.

Type 4 – New evidence presented includes how Ofgem are using volatile information to fine tune returns for long run businesses, how MARs evidence is difficult to interpret and must be treated with considerable caution, why 3 listed water companies shouldn't be used to draw inferences for energy networks, how the transaction premia used pre dates the RIIO-2 process, how Ofgem are making a raft of changes to address perceived excess returns and then an introducing the outperformance wedge to address for the same errors and finally why the use of MAR further erodes the incentive to outperform.

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?

The need for an ex post adjustment, which could be interpreted as a safety net if Ofgem's allowed vs expected returns mechanism does not work, outlines the fundamental concerns we have with the concept of applying an outperformance wedge in general. We also highlight how the ex post adjustment would not have the same impact on financeability as not making the 25bps deduction from cost of equity in RIIO-2 in the first place. Therefore, the allowed vs expected returns assumption cannot be included in the financeability assessment for RIIO-2.

Furthermore, we believe the following issues are inherent in the mechanism;

- **Weakened incentives to outperform** The ex-post adjustment mechanism will further weaken the incentives on companies to drive down costs and improve customer service. As shown in section 5.1 of Frontier's report 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. Given that this perverse incentive would be layered on top of weakened incentives to outperform, this is a material and concerning impact.
- **Difficulties in Creating a Level Playing Field** The ex post adjustment relies on the companies in question being highly similar, and cost and incentive assessment to be perfectly calibrated across all companies that are pooled together. Where there are marked differences, outcomes versus the average sector performance can end up being arbitrary and unfair as a result. Looking at the specific poolings of companies;

For the gas companies:

- The group contains a transmission network and distribution networks that face markedly different regimes and circumstances, for example;
- totex incentive rates are very different as between distribution and transmission (see Figure 6 below); and
- the companies face entirely different ODI frameworks and cost assessment techniques.
- There may be important regional differences between gas distributors that may not have been captured perfectly.

For the electricity companies:

[570] Monitoring Financial Resilience, Ofwat, January 2020. See slide 15.

- each licensee operates a very different network serving a different region;
- their business plans are far more bespoke and tailored as a result, limiting their direct comparability (for example the application of PCDs are highly individual); and

while output regimes are broadly similar, each has been calibrated on a bespoke basis

- **Weakened Incentives to Collaborate** The type of ex-post incentive envisaged would materially harm any scope for co-operation across the sector on output delivery. Companies now have the potential to benefit from weak performance delivered by sector peers. Hence any licensee which identifies a great new innovation or pushes the boundaries of best practice is unlikely to want to share that information with others. Better performance by others in the sector would now reduce the prospects of a true-up being applied. Given the potential importance of cooperation across the sector in driving performance and delivering whole sector solutions, this deterrent to collaboration could prove harmful to sector performance and hence customer interests.
- **Impact on long-term Productivity** The ex-post true-up being considered here by Ofgem would not in any circumstances offset the negative impact on productivity, and in many cases, makes the impact much worse. Therefore, our arguments outlined above on the long-term consequences on productivity of the gas and electricity sectors would still be applicable.
- **Financeability** Ofgem state in footer 157 of the DD Finance Annex, p99, that;

  'Evidence suggests equity investors should expect at least 0.25% in outperformance returns and we are proposing an ex-post top up if outperformance does not materialise as expected, so we believe it is appropriate and justified to include it in financeability analysis'.

We believe the ex post adjustment should not be reflected in the RIIO-2 financeability assessment for the following reasons;

- Any one company is not certain to receive this adjustment. Even if a company fails to deliver at least 25 bps of outperformance, it is by no means certain that it will receive additional returns through this ex-post adjustment. This is because the adjustment requires average performance (from the relevant comparator group) to be below 25 bps. As such, any one company's chance of receiving the adjustment depends on the toughness of other companies' allowances and those companies' chances of outperforming.
- any potential adjustment will be calculated at the end of the RIIO-2 price control period. This means that any income generated through the adjustment will only increase cashflow in the next regulatory period and cannot help to secure financeability in the forthcoming period.
- There is also an element of regulatory risk around how Ofgem will choose to apply this mechanism. The ex post true up would only be calculated during the close out period, alongside a vast array of other ex post assessments, appraisals and true ups. Companies may perceive some outcome as being likely going into that process, but can have no certainty over how Ofgem will actually administer the true up in the end. Indeed the existence of the true up may have consequences for the way in which Ofgem approaches its close process., There is clearly a material regulatory risk around this element of the return and it cannot be regarded as guaranteed.

It is therefore clear that the ex post adjustment would not have the same impact on financeability as not making the 25bps deduction from cost of equity in RIIO-2 in the first place. Therefore, the allowed vs expected returns assumption cannot be included in the financeability assessment for RIIO-2.

Type 1 - Factual or computational errors. The need for an ex post adjustment, which could be interpreted as a safety net if Ofgem's allowed vs expected returns mechanism does not work, outlines the fundamental flaws with the concept of applying an outperformance wedge in general. Furthermore, the ex post adjustment itself has a number of an inherent issues.

Type 4 – New evidence presented includes how the ex post adjustment would further weaken incentives drive down costs and improve customer service, difficulties in creating a level playing field, weakened incentives to collaborate, further impact long term productivity and how the ex post adjustment does not mean the outperformance wedge should be included in the RIIO-2 financeability assessment.

Alternatives to an Outperformance Wedge

Ofgem considered four alternative policy options to an outperformance wedge, each of which is considered below and considered in further detail in section 6 of Frontier Report 1;

Set Neutral cost and performance targets

This is a much more beneficial strategy to consumers as removing the outperformance wedge and setting targets symmetrically will avoid all the negative incentive effects outlined in response to FQ10, and ensure that companies face the full strength of incentives to outperform cost allowances and meet or beat other output based incentives. In introducing the outperformance wedge, Ofgem appears to be moving towards rate of return regulation due to a reticence to have potential outperformance of any note, despite the fact this means customers face underinvestment, inefficiency and worse levels of service.

Conversely, through incentive based regulation, allowed prices or revenues are set in advance, but opportunities to out or underperform are also introduced. Introducing the opportunity to outperform creates the incentive for companies to innovate and look for ways to deliver their services for less, and to deliver better services for customers. For many decades, regulators have struck the balance of using these incentives but time limiting the period that companies can receive rewards for any outperformance by updating price controls every few years. On balance this strikes the best deal for customers.

RIIO-1 may have led to higher than expected returns for some companies but this does not mean that price controls in general cannot be calibrated fairly and symmetrically. There are a number of factors in RIIO-1 which led to the out-performance – along with actual efficiency gains by network companies which included a number of factors outside the control of network companies, particularly:

- lower than expected RPEs (which is likely to be due to the unforeseen weakness in real wage growth post the global financial crisis)[571]
- the fact that the price control lasted for 8 years inevitably leading to greater forecast error.

There is no reason to suppose that the factors beyond network control will continue to be observed in RIIO-2 because they are either not relevant for RIIO-2 or have been mitigated directly by relevant proposed indexation mechanisms and Ofgem's measures to limit outperformance (as detailed in section 4 of Frontier report 1). This already provides a clear reason why the calibration of RIIO-2 will be far more symmetric ex ante. Furthermore, as shown in our response to FQ10, while we reject the need for an outperformance wedge in principle, once the differences between RIIO-1 and RIIO-2 are properly accounted for then the likely level of RIIO-2 outperformance is zero, based on restating historical RIIO-1 returns.

We note that Ofwat has not resorted to adjusting the baseline allowed return on equity in anticipation of future outperformance, in its PR19 determinations. In fact, Ofwat has arguably set tremendously challenging packages for the water companies, and even by its own estimation, shows a profile of risks for most water companies with a slight tilting towards the downside. Many water companies consider Ofwat's characterisation of risk unachievable, and that it is over-estimating the upside and under-estimating the downside. Indeed, an unprecedented four water companies have referred the Final Determination to the CMA. However, it is clear Ofwat has been sought to calibrate a tough price control (potentially too tough) without resorting to blanket adjustments to headline returns. It's worth noting that the CAA also did not adopt a mechanism to adjust the baseline return on equity in anticipation of outperformance, nor has it featured in CMA redeterminations - Ofgem is the only regulatory body we're aware of that has adopted this mechanism.

Lower incentive strengths

Lowering the strength of incentives, will reduce the amount of time and energy that companies put into innovating to find cost savings and ways of delivering more for less. This will lead to lower productivity and lower service levels for consumers. Ultimately customers will get a worse deal in the short run and the effect will likely grow to become material in the long run.

Asymmetric incentives or incentive strengths

Making the penalties for underperformance larger than the incentives for underperformance would skew incentives, and lead to ex-ante expectations of underperformance. This may lead investors to expect returns below the required rate, which could weaken incentives to invest, and lead to worse customer outcomes over time. This will also reduce the chance that companies carry out innovation, as this is naturally riskier, and companies will be particularly averse to options that lead to more risk in terms of possible performance levels.

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571 Applicable to companies that were awarded RPEs.

Competed, fixed or zero pot incentives:

Setting incentives that depend not only on what you do but also what other companies do will necessarily reduce the chance that a given company receives a reward. This will have a similar impact to the lowering of unit incentive rates. Incentives to outperform will be reduced, and this will lead to lower productivity and worse customer outcomes.

Overall, we believe that Ofgem should not consider any of these alternatives, when it has a clear optimal strategy of setting symmetric targets in the first place.

Views on Averaging, Pooling or Suggested simplifications

We have set out our strong objections to the outperformance wedge and why ex post adjustments are not appropriate, above, and in response to FQ10. Therefore, we do not feel it is appropriate to comment on the nature of the ex post adjustment given these objections and the difficultly in interpreting how the ex post adjustment will play out in practice.

Type 3 - Disagreement as to how the methodology should be applied

SGN believe it is much more beneficial to consumers to set neural cost and performance measures to incentivise networks to achieve cost efficiencies and improve service, rather than introduce the many negative incentive effects as detailed above and in answer to FQ10. Lower incentive strengths or asymmetric incentives would, like the outperformance wedge, be detrimental to consumers.

Type 4 – New evidence presented justifies why neutral cost and performance measures should be used rather than implementing the outperformance wedge.

6.4 WACC Allowance

Please see our responses on cost of debt (section 6.2), cost of equity (section 6.3) and notional gearing (FQ13).

6.5 Financeability

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

Ofgem has a statutory duty to have regard to the need to secure that companies are able to finance their licenced activities.[572] However, we believe it is Ofgem's inappropriate and unjustified DD Finance assumptions that drive the notional companies assessed financeability rather than true measures of its financial resilience. We believe this undermines whether the test is meaningful and whether it robustly tests that the DD package is appropriately calibrated.

Based on the analysis of risk we have conducted, the credit metrics implied by the DD mean that the notional company struggles to comply with the licence obligation to maintain an investment grade credit rating even at P50 risk levels, suggesting the package is not financeable in the way that Ofgem suggests as there is insufficient headroom to manage even a small proportion of its risks. We explore these points further below;

Underlying Assumptions

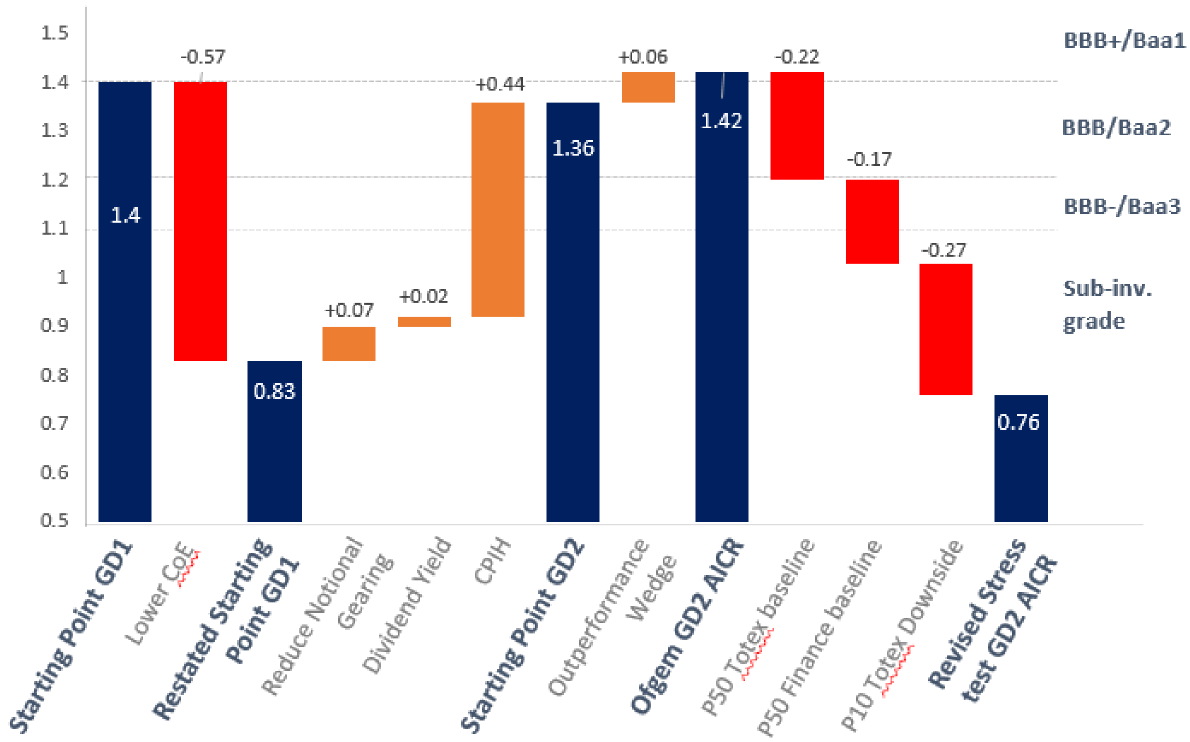
When considering the financial attributes of the package, we submitted a business plan that was assured by the board as being financeable under the actual and the notional company[573]. This was based on the working assumptions that were specified by Ofgem.

As raised in our Business Plan submission, it is possible to obtain inappropriate and misleading results from financial metrics.

Taking the position at the end of GD1 (65% notional gearing), after adopting Ofgem's significantly lower cost of equity assumption, the notional company relies on a series of adjustments and assumptions to achieve a target investment grade credit rating in the current regulatory period. This results in notional company credit metrics of BBB / Baa2 credit ratings which is clearly a significant weakening of credit quality from GD1 and relies on an assumption of outperformance

[572] Section 4AA of the Act.
[573] SGN business plan, Dec 2019, Chapter 18, table 18-4

of 25bps to just achieve credit metrics consistent with BBB+/Baa1 credit ratings (1.4x the lower threshold for AICR). The impact of these assumptions and adjustments are shown in the AICR bridge below;



The relevant FQ responses where these assumptions and adjustment have been challenged are as follows;

- Lower Cost of Equity: FQs 4-9
- Notional Gearing: FQ 13
- Dividend Yield: Section 6.11.7
- 100% switch to CPIH: FQ21
- Application of Outperformance Wedge: FQs 10-11

Asymmetrical Downside Risk of DD Package

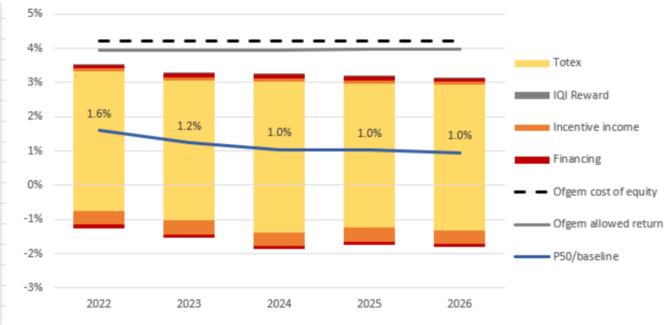
It is vital that the notional company maintains sufficient headroom to absorb shocks. This analysis and board assurance to date has been predicated on the assumption that there is a reasonably symmetrical balance of risks. However, what is clear from the DD package is the risks are extremely asymmetrical and this generates substantial downside risk which provides plausible scenarios that breach the licence obligation to maintain investment grade ratings, and consequentially undermine the ability of the sector to attract debt and equity finance at an efficient cost.

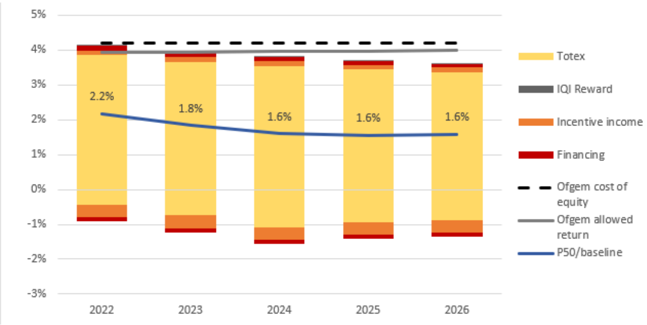
PwC's independent risk analysis (see PWC report 1), conducted for SGN, provides an estimate of the likely performance of the business against the DD (P50), a cumulative downside (P10) and a cumulative upside (P90). This analysis shows that the likely returns are heavily skewed to the downside. The projected GD2 RoRE for Southern is 1.17% and for Scotland 1.75% compared to Ofgem's allowed return of 3.95% and Ofgem's cost of equity estimate of 4.2%. In the cumulative upside, it is highly unlikely that SGN will be able to achieve Ofgem's cost of equity. In the cumulative downside the RoRE extends significantly below zero. This means there is a material risk of negative returns which is an unattractive outlook for equity investors in utilities.

The distribution of potential RoRE returns from PwC's report is set out below.

<u>Southern</u> <u>Scotland</u>

Classified as Highly Confidential





Source: PwC

This demonstrates that the package is too heavily skewed to the downside and is not consistent with the 'fair-bet' principle.

Recalibration of all areas of the package, as justified by evidence set out in this document, is the only remedy.

The changes required to have a robust and financeable RIIO-2 package are:

- The ongoing efficiency challenge needs to be reduced to a realistic and plausible level.
- The technically assessed projects are judged on a fair basis and not penalised relative to benchmarked models.
- Time is allowed to correct and reissue the benchmarking models so that we can have a greater confidence in their accuracy and appropriateness.
- [redacted]
- That all the core costs are covered in an appropriate manner through an ex ante allowance, and that uncertainty mechanisms are sufficiently clearly specified, and decisions are made in a timely manner to minimise barriers to investment and reduce costs
- That customer supported workloads with an immediate safety requirement or where investment generates an immediate and substantial environmental benefit should be reinstated alongside their efficient costs of delivery.
- That returns on equity are appropriately calibrated, including to reflect the specific risks of gas networks.
- That the cost of debt allowance provides appropriately for borrowing costs incurred.
- That Ofgem works together with licensees to remove errors, inconsistencies, double counts and misunderstandings.

Notional Company Mitigations

As per para 5.24 of the DD Finance Annex, Ofgem believe that the following mitigating actions are available to the address and financeability concerns;

- Reducing the dividend yield assumption
- Adjusting notional gearing (which implies notional equity injection)
- Adjusting capitalisation rates and, or depreciation rates

As set out in section 1 above, Ofgem have already used the first two mitigations ahead of the financeability assessment, when making changes from GD1. With respect to flexing capitalisation and/or depreciation rates SGN believe adhering to using capitalisation or depreciation rates that reflect the creation or use of underlying assets is the best approach to maintain a sustainable, long-term cost structure for the benefit of customers. Furthermore, the results from our detailed consumer engagement show that consumers believe current and future customers should pay their fair share of long-term investments.[574]

[574] SGN business plan, Dec 2019, Chapter 18.2.2

We note Ofgem state on p214 of the DD Finance Annex that only one of the credit rating agencies have indicated they take speed of money adjustments into account (S&P) to improve short term liquidity. Ofgem recognise the majority of the major credit rating agencies don't take it into account, as they assess both underlying creditworthiness and whether adjustments have a short-term benefit to the detriment of the company's longer-term position, therefore we don't think it is a viable mitigation. We further note, in para 5.26 of the DD Finance Annex, Ofgem believe there are limitations in the AICR and PMICR ratios calculated by Moody's and Fitch, respectively, who don't take into account speed of money adjustments. The crucial point is that the methodology used by the majority of the rating agencies is critical as it is their assessment which is relevant as to whether a company is able to maintain investment grade credit ratings, and thus target thresholds need to be calculated on the same basis to maintain sufficient headroom.

Furthermore, we note that Ofgem state, on p214 of the DD Finance Annex, that

"We remain of the view that if there is a cashflow issue that is expected to be short term due to a lagged effect of a change in rates environment that could be expected to feed into cost of debt more slowly than cost of equity, that measures that address this can be valid ways to improve credit quality."

As shown in the Underlying Assumptions and Asymmetrical Downside Risk of DD Package **sections** above, the price control package is not viable. This is not a temporary cashflow issue that can be mitigated by further pre or post financeability assessment measures but is a fundamental issue that needs to be recalibrated as detailed at the end of the latter section.

Need for Strong BBB+/Baa1 rating

As highlighted above we support the rational for targeting BBB+ in para 5.17, but believe the notional company should be targeted at strong BBB+/Baa1 due to;

- Compared with the GD1 price control, increased regulatory, political and industry risks, as well as persistent elevated volatility compared to the wider market, means that stronger credit metrics need to be targeted as qualitative metrics can't be assumed to be as strong in GD2 as GD1. On p212 of the DD Finance Annex Ofgem disagree with this point as they believe cost of equity and debt allowance indexation reduces risk. However, they have not taken into account the significant asymmetrical risk highlighted above, which has increased risk in RIIO-2 relative to RIIO-1. These risks, and the regulatory and political risks evidence put forward in our response to FQ5, mean a strong BBB+ target credit rating needs to be targeted.

  The expert stakeholder engagement for our December Business Plan submission[575] supported this;

  - all 15 expert stakeholders interviewed as part of December Business Plan submission identified there had been an increase in risk associated with investing in UK utilities over the past 5 years.
  - There was concern among stakeholders that there is a 'race to the bottom' on setting the cost of capital across UK regulators. Several commented that these reductions are inconsistent with (and in fact contradict) the increased risk position
  - With a number of new regulatory mechanisms that depart from previous price controls, most interviewees considered that the profile of prospective risks in the energy sector is skewed to the downside. Stakeholders also considered that these changes have made the regulatory regime for UK energy networks less predictable and stable
- Stakeholder feedback received is that financial stakeholders do not view the UK energy sector as an attractive equity investment opportunity[575], so it is necessary for network companies to maintain solid credit ratings to retain the ability to access capital.
- Notwithstanding the points above, if the assessment of financeability relating to core credit metrics did not fall comfortably within a rating notch score band then a company would risk a rating downgrade from relatively small movements in the following factors (versus the price control determination assumptions):
  - Cashflows can vary as totex will not turn out exactly as predicted (due to timing rather than any performance against regulatory targets) which means cashflows will vary around the average figures projected from the outset

[575] SGN business plan, Dec 2019, Chapter 18.2.1

- Regulatory funding, particularly of items subject to uncertainty mechanisms, often produces delay between cash outflow and cash inflow;
- Macro-economic impacts such as changes to inflation and economic disruption can create variability in net debt to RAV and cash flows from those forecast and take averages below the minimum thresholds.

Qualitative Assessment

Energy networks face a series of specific political, regulatory and industry risks, which has not slowed during the RIIO-2 process.

In our business plan we reviewed the impact of political and regulatory changes on the risk of utilities relative to the wider market. This variability demonstrates that investments in UK utilities are inherently riskier than they have been during previous price controls. We consider the political interest in energy, the policy challenges around net zero and the changes to the regulatory framework means that this volatility is unlikely to subside quickly.

Compared with the GD1 price control, this increased regulatory, political and industry risks has a number of implications for the GD2 price control:

- it is appropriate to target stronger credit metrics. Our stakeholder engagement[576] showed that debt investors and ratings agencies generally agreed that target ratings for the energy sector should be around A/BBB+. However, stakeholders considered that Ofgem's proposed cuts to returns will make it harder for companies to achieve the A/BBB rating level that Ofgem uses to benchmark the cost of debt;
- it is appropriate to target strong quantitative credit metrics with greater headroom above existing thresholds, as qualitative metrics can't be assumed to be as strong in GD2 compared to GD1. Additionally, SGN has substantially less ability to influence its rating on qualitative factors, such as the stability and predictability of the regulatory regime and cost and investment recovery, which together account for 30% of the Moody's assessment; and
- investors should be adequately compensated for bearing elevated risk over GD2. Most stakeholders consider Ofgem's current proposed allowed return on equity (3.95% real, CPIH) is too low to compensate investors for the risk associated with investment in energy networks. This should be considered when selecting the point estimate for the asset betas from within the range of evidence.

Looking forward, it also shows that returning to a stable, predictable political and regulatory environment will support low cost and efficient financing, thereby providing long-term benefits to customers.

Stress Tests

SGN disagree with Ofgem's statement there is significantly less systematic risk in the RIIO-2 price control compared to RIIO-1, as set out in our response to FQ6a. Furthermore, as set out in the Underlying Assumptions section above we strongly believe the notional company needs to be assessed once the outperformance wedge has been removed (as there is no guarantee that this will be achieved or that the ex post adjustment will transpire in the following price control if a company doesn't achieve it).

We believe that the stress tests put forward by Ofgem were limited as they only took account of high-level Totex scenarios, both in terms of uncertainty mechanisms and Totex underperformance. Stress tests should also include the material factors of downsides in incentive income, interest rates, inflation and other areas of the regulatory framework which result in additional risk.

In the Table below, we set out the financial metrics for SGN and its two networks. This also shows the threshold for the BBB+ rating which we consider is the appropriate rating to target, and is consistent with Ofgem's cost of debt calculation.

This analysis shows that on a P50 basis, the AICR ratio drops to 1.03x and under P10 conditions falls to 0.76x, well below investment grade levels. This clearly demonstrates that the DD package, despite substantial short term and flattering mitigations, does not provide adequate headroom to absorb even P50 risks. Any further mitigations in terms of accelerating cashflows are not acceptable as this is pushing the underlying credit quality problems into RIIO-GD3 and

[576] PWC (November 2019) 'Financial Stakeholder Engagement – For SGN's RIIO-GD2 Business Plan'

beyond and will not be acceptable to credit rating agencies. Recalibration of all areas of the package, as justified by evidence set out in this document, is the only remedy.

Metrc	BBB+ threshold	Southern			Scotland			SGN		
		P50/Baseline	P10 (cuml.)	P90 (cuml.)	P50/Baseline	P10 (cuml.)	P90 (cuml.)	P50/Baseline	P10 (cuml.)	P90 (cuml.)
AICR	> 1.4x	1.04x	0.78x	1.20x	1.01x	0.74x	1.18x	1.03x	0.76x	1.19x
PMICR	> 1.5x Senior; 1.7x IDR	1.14x	0.87x	1.29x	1.12x	0.85x	1.28x	1.13x	0.86x	1.28x
Nominal PMICR	> 1.8x Senior; 2.0x IDR	1.78x	1.53x	1.91x	1.71x	1.46x	1.86x	1.75x	1.51x	1.90x
FFO:Debt	> 9%	8.9%	7.4%	9.4%	8.9%	7.5%	9.6%	8.9%	7.4%	9.5%

Importance of Attracting and Maintaining Investment in the Energy Sector

Furthermore, significant consideration needs to be given to the long term financeability of the industry. To meet the challenges and changes ahead due to the move to net zero, long term equity investors are required. To do this a price control package is needed that is sustainable for the long term, not based on a financeability assessment that;

- uses various fundamental changes in assumptions from GD1, as highlighted in the Underlying Assumptions section above, to mask the impact of a circa 50% drop in cost of equity from GD1
- ignores the significant downside asymmetric risk of the package as highlighted in the Asymmetrical Downside Risk of DD Package section above, and its significant impact on regulatory returns

A key finding on the expert stakeholder engagement[577] for our December Business Plan was that Stakeholders commented that setting such a low WACC would force companies to focus on short-term financial targets, making it harder for companies to make long-term plans, passing the risk and expense of solving future challenges onto future generations. Several stakeholders suggested that Ofgem could do more to enable companies to deal with longer-term industry risks, such as asset stranding for gas distribution networks[575]. This was supported by the majority consumers agreeing its important to have long term investors who are able to fund the green energy solutions that customers want[574]

Type 4 – New evidence presented on why Ofgem's DD Finance assumptions inappropriate and unjustified

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

SGN believe that Ofgem have not justified the move from RIIO-GD1's 65% notional gearing and we believe 65% is an appropriate assumption for RIIO-GD2 as evidenced by the low current cost of debt and market expectations, the requirement of a substantial equity injection if notional gearing is dropped and the average level of actual gearing for utility companies.

SGN believe that Ofgem's approach to determining notional gearing is flawed. As set out in paras 5.46-5.48 of the DD Finance Annex, the analysis starts with a financeability assessment at 60% and then assesses whether there is excessive headroom to increase notional gearing, or sufficient headroom to remain at 60%. At no point can we see an impact assessment of whether the notional gearing should move from the GD1 level of 65%, and whether there are any assumptions in the DD package that have been calibrated incorrectly to force Ofgem to drop notional gearing to 60% (in order to give what in Ofgem's view are satisfactory credit metrics). Therefore, notional gearing should be assessed as the final check on financeability once the package has been appropriately calibrated.

As detailed in our December Business Plan submission[578] , we strongly believe 65% is a more appropriate notional gearing as;

- The average actual gearing of utility companies is 66% and with the vast majority of companies having maintained a strong credit rating at this level. This indicates that it is an appropriate notional standard for the industry. It is

[577] PWC (2019), Financial stakeholder engagement For SGN's RIIO-GD2 Business Plan
[578] section Biii of our December Business Plan Financeability Appendix 004i

worth nothing that the credit rating agency guidance for BBB+/Baa1 is below 73% (Fitch) and below 75% (Moody's and S&P)

- Given low debt cost, caused by interest rates having come down to record lows during RIIO-1, and the market expectation that interest rates will remain low over the next 3 years, there appears to be limited evidence or justification to support a downward adjustment to the RIIO-GD1 notional gearing assumption of 65%.
- The drop in notional gearing means an equity injection of £300m is required for the notional company in a price control where the cost of equity has been approximately halved in comparable real terms

Type 5 - Evidence that SGN has provided on Notional Gearing but hasn't been taken into account

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?

SGN believe the significant uncertainty surrounding Covid 19 is another reason, in addition to those detailed in our response to FQ12, why the minimum credit rating for the notional company needs to be targeted at a strong BBB+. Furthermore, in times of industry and wider economic uncertainty, the need to have strong resilient energy networks is paramount.

6.6 Financial resilience

SGN believe the need for further financial resilience measures, on top of the suite of protective measures already in place in networks' licence conditions, is indicative of the financeability of the proposed DD package as set out in our response to FQ12. Therefore, the focus should be on implementing the changes required for a robust and financeable RIIO-GD2 package.

Type 4 – New evidence presented on financial resilience

6.7 Corporation tax

SGN believe that a notional tax allowance should be retained for RIIO-2 with care taken in the balance between implementing additional protections and their resource burden and actual effectiveness. We welcome a threshold being applied to the tax reconciliation process but believe this should be increased to 1% of base revenue in line with re-openers and the order of magnitude for external audits.

The tax review process has to be symmetrical, ie it needs to be made clear that it applies when allowances are incorrectly below actual costs as well as above, with recognition that there needs to be incentivisation to be as tax efficient as possible and that the application of a sharing factor needs to be considered. Finally, board assurance isn't required as assurance is already provided by complying with existing tax legislation and we are already required to publish a signed off tax strategy/policy which outlines how we comply with tax legislation.

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

In order to minimise costs to consumers there needs to be incentivisation to drive down tax costs. In principle this option is best placed to do this. However, care needs to be taken in the balance between implementing additional protections, and consideration of their actual effectiveness and the impact of their resulting resourcing costs on the consumer. To this end we believe the sharing factor used for Totex under/over performance needs to be considered as a replacement for some of the less effective and costly protections – driving costs down for the consumer through lower resource implications and incentivising networks to drive tax costs down further.

6.7.1 Other areas

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?

We support allocation and allowance rates being updated yearly during RIIO-2 so that actual tax and allowed calculations are further aligned – to assist with the tax reconciliation process. On this basis we believe the capital allowance balances should use a RIIO-1 closing balance based on actual totex for all years of RIIO-1. This balance can be updated through the RIIO-1 close out process.

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 welcome a materiality threshold being applied to the tax reconciliation given the resource intensive nature of this work. However, we see no reason why the materiality threshold should not be aligned with other re-openers, i.e. 1% of base revenue. Aligning with a materiality threshold (0.33% of base revenue or 1% corporation tax change applied to type A tax trigger events) that is proposed to be removed in RIIO-2 and was related to a mechanism that has minimal resource implications, does not seem a reasonable approach. Also 1% of base revenue is also broadly in line with the level of materiality we would expect from our independent external audit.

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

We agree with retaining the tax trigger and clawback mechanisms from RIIO-1, with the materiality threshold being removed for type A events.

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

It needs to be clear that the tax review process, and any subsequent changes to tax allowance, is not one sided. i.e. it's not just for when a stakeholder believes tax allowances are incorrectly above actual tax costs, but is also when they are incorrectly below actual tax costs. Also, there has to be incentivisation to be as tax efficient as possible – legitimate under/over performance needs to be allowed, with the application of a sharing factor to be considered.

d. Do you have any views on the proposed board assurance statement? Return adjustment mechanism questions

It is unclear why Ofgem are looking to duplicate the role of the HMRC. Board assurance isn't required as assurance is already provided by complying with existing tax legislation and we are already required to publish a signed off tax strategy/policy which outlines how we comply with tax legislation. Furthermore, it's not the role of the board to be assuring whether Ofgem mechanisms, e.g. tax allowance calculation, are appropriate.

Type 4 – New evidence presented on corporation tax

6.8 Return adjustment mechanisms (RAMs)

SGN are disappointed to see such a move away from incentive based regulation, especially as there has not been an in depth review of this fundamental change in regulatory policy. We believe that individual causes of any outperformance in RIIO-1 that weren't driven by company behaviour have been addressed in the RIIO-2 proposals through stronger links to delivery, greater use of uncertainty mechanisms and volume drivers, reopeners, tougher targets and allowances. Therefore, there isn't the need to introduce fundamental changes to incentive based regulation.

Also, there is significant asymmetrical downside risk in the DD package. It is fundamental that this is resolved, but if the asymmetry does remain then the collar should reflect the asymmetric downside risks highlighted in PWC Report 1 and have a narrower threshold than -300bps.

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

SGN are disappointed to see such a move away from incentive based regulation, especially as there has not been an in depth review of this fundamental change in regulatory policy. There was an in-depth review into how the energy markets should be regulated (the RPI-X@20 review) before the establishment of the RIIO principles. We believe that individual causes of any outperformance in RIIO-1 that weren't driven by company behaviour have been addressed in the RIIO-2 proposals through indexation stronger links to delivery, greater use of uncertainty mechanisms and volume drivers, reopeners, tougher targets and allowances. Therefore, there isn't the need to introduce fundamental changes to incentive based regulation.

When set properly these mechanisms mean there shouldn't be any need for RAMs or allowed versus returns mechanisms which are simply overlaying additional mechanisms to solve the same perceived problem of RIIO-1 excess returns. It should also be noted that in water outturn RORE ranges have been kept somewhat tighter than in RIIO-1 and Ofwat have not felt it necessary to introduce RAMs in PR19.

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?

Notwithstanding our comments on the introduction of RAMs mechanisms in response to FQ18, SGN believe cap and collars should be calibrated in line with the levels of incentivisation required to drive efficiencies in performance, and thus reduce costs and improve service to the benefit of current and future customers.

As highlighted in our response to FQ12 there is significant asymmetrical downside risk in the DD package. It is fundamental that this is resolved, but if the asymmetry does remain then the collar should reflect the asymmetric downside risks highlighted in PWC Report 1 and have a narrower threshold than -300bps.

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

We have no further comments on the RAMs proposals for RIIO-2

6.9 Indexation of RAV and calculation of allowed return

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

Consistent with the approach in PR19, we believe transition to CPIH indexation is required to maintain the trust and confidence of investors. This is because historic investment, which will constitute the vast majority of the RAV during RIIO-2, would have been financed by either equity invested, or debt undertaken, on the firm basis of RPI indexation.

Using the immediate switch to CPIH to accelerate cashflow to mitigate low returns, may provide protection to debt investors, but only as a result of shifting material risk to equity investors. We have not seen a full impact assessment of the merits of a 100% switch to CPIH indexation vs transition.

We recognise the issues with using RPI as a forward looking measure. However, consistent with the approach in PR19, we believe transition to CPIH indexation is required to maintain the trust and confidence of investors. This is because historic investment, which will constitute the vast majority of the RAV during RIIO-2, would have been financed by either equity invested, or debt undertaken, on the firm basis of RPI indexation.

The 0.4x increase in AICR/PMICR due to the immediate switch to CPIH, as shown in our response to FQ12, is not a fundamental improvement in the profitability of the business. Therefore, Ofgem should be careful about netting this movement off against other regulatory changes which would reduce the profitability of the business, for example, through a lower WACC. Using the immediate switch to CPIH to accelerate cashflow to mitigate low returns, may provide protection to debt investors, but only as a result of shifting material risk to equity investors.

The following factors need to be taken into account, which were highlighted in CEPA's 'Review of Cost of Capital Ranges for Ofgem's RIIO-2 for Onshore Networks' and are exaggerated by an immediate switch to CPIH rather than a transition;

- the impact of the fact that CPI linked investments are probably less desirable for investors resulting in a larger cost of equity for these investments. This may be particularly relevant for investors with large RPI liabilities such as pension schemes.
- a considerable number of investors have a preference for capital growth vs cash income. For long life assets (i.e. 40-60 years) changing to CPI would materially adjust the asset valuations in the intervening period. Also, a number of investors have significant RPI linked liabilities and thus have a strong preference for a RPI linked asset.

The immediate move to CPIH has clearly provided a significant financeability boost. However we have not seen a full impact assessment of the merits of a sudden 100% switch from RPI to CPIH indexation on 1st April 2021 versus a transition, and fear this has been used as a financeability mitigating lever as set out in our response to FQ12.

Type 5 - Evidence that SGN has provided on merits of transition to CPIH indexation but hasn't been taken into account

6.10 Regulatory depreciation and economic asset lives

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 believe a 45-year asset life assumption should be retained from RIIO-GD1 as this provides a reasonable assumption of the economic life of the asset. Asset life was assessed as part of the RIIO-GD1 process with a number of factors considered including technical asset life, existing age of the network and statutory/regulatory accounts treatment, and scenarios for the future use of the gas network. With the backdrop of this uncertainty CEPA proposed that making a change to asset lives is not justifiable. We believe this is still the case until government carry out their review of heat policy.

Also, as per RIIO-GD1, we believe a 45 year asset life should be combined with the sum of digits (front loaded) depreciation approach for RIIO-GD2 to reflect the significant uncertainty and risk that gas distribution has in the future use of its assets compared to other energy network sectors. Gas distribution was the only sector to have front loaded depreciation in RIIO-1 to reflect these asset stranding risks and, as highlighted in our response to FQ6 these risks are even more relevant to RIIO-GD2.

We do not believe any changes to asset lives and depreciation would aid financeability due to rating agency treatment and is not supported by our customer engagement in our Business Plan submission[579]

6.11 Other finance issues

6.11.1 Capitalisation rates

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

We agree that Capitalisation rates should be aligned with accounting treatment, i.e. that capex and repex should be 100% capitalised and opex 0% capitalised. This use of 'natural capitalisation rates' was also supported by the financial stakeholder engagement in Financeability Appendix 004O of our December 2019 Business plan submission. We specifically sought to gather their views on whether current customers or future customers should pay a greater proportion of high-cost investments made today. The informed customer panel advocated that both current and future customers should pay their fair share. Indeed, the majority agreed that the cost of building and operating a pipe should be fairly spread over customers' bills across the next 45 years.

[579] SGN business plan, Dec 2019, Chapter 18, section 18.2.2

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 believe the mechanisms put in place need to reflect the capitalisation rates required for each of the uncertainty mechanisms, this would avoid the need for uncertain ex post adjustments in capitalisation rates.

6.11.2 RAV opening balances

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

SGN have no problem in principle with Ofgem using the latest actual and forecast data at the time of Final Determination (FD) to determine a forecast closing RIIO-1 RAV balance, that acts as the opening RIIO 2 balance. The final RIIO-2 opening balance should be updated following a robust close out mechanism.

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

SGN agree that estimated opening RIIO-2 balances should be used until the closing RIIO-1 RAV balances have been finalised, as per our response to FQ25. Furthermore, for FD the closing RIIO-1 balances should be updated for 2019/20 actuals and the latest 2020/21 forecast, both of which have already been submitted to Ofgem. We also believe that specific RIIO-1 RAV disposal adjustments we made in our Business plan submission have not been implemented in line with the PCFM treatment, i.e. trued up at the beginning of RIIO-GD2, and so this also needs to be addressed in the FD.

6.11.3 RIIO-1 close-out questions

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

SGN agree with the three categories of close out adjustments, as detailed on p152 of the DD Finance Annex

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 would welcome clarity asap pre-Final Determination on how Ofgem are proposing to model these parameters, and their respective level, so we can input into this process. Additionally, we would welcome input to the wider Licence Model and future PCFM in these timescales to resolve differences with our internal model and gain further clarity on functionality.

6.11.4 Amounts recovered from the disposal of assets

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?

SGN agree assets proceeds should be incentivised in this manner

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?

SGN believe this is consistent with arrangements in GD1.

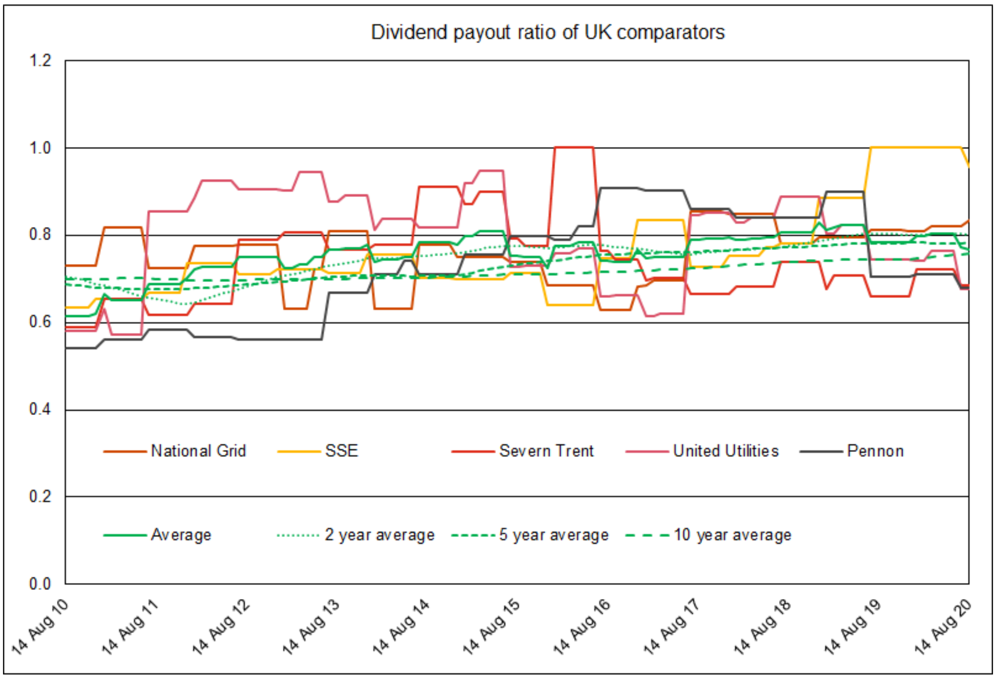
6.11.5 Dividend yield assumption

We view that a more valid notional dividend yield assumption, which is calibrated using a reasonable set of comparators which are consistent with Ofgem's beta analysis, is between 4% and 4.5%. This is evidenced below using dividend pay-out ratios as per Ofgem's challenge to companies to do so in para 11.41 of the Finance Annex.

As set out in para 11.41 of the Finance Annex, Ofgem has used dividend cover and dividend pay-out ratios (DPR) as the basis of supporting its assumption of a 3% dividend yield and stated that companies have not used these metrics in their analysis to date. In para 11.42 of the DD Finance Annex Ofgem use the average DPR for the FTSE 100 stocks and the Stoxx Europe 600 index to infer a DPR of 50% for SSE and NG; and calculate a dividend yield of approximately 3%.

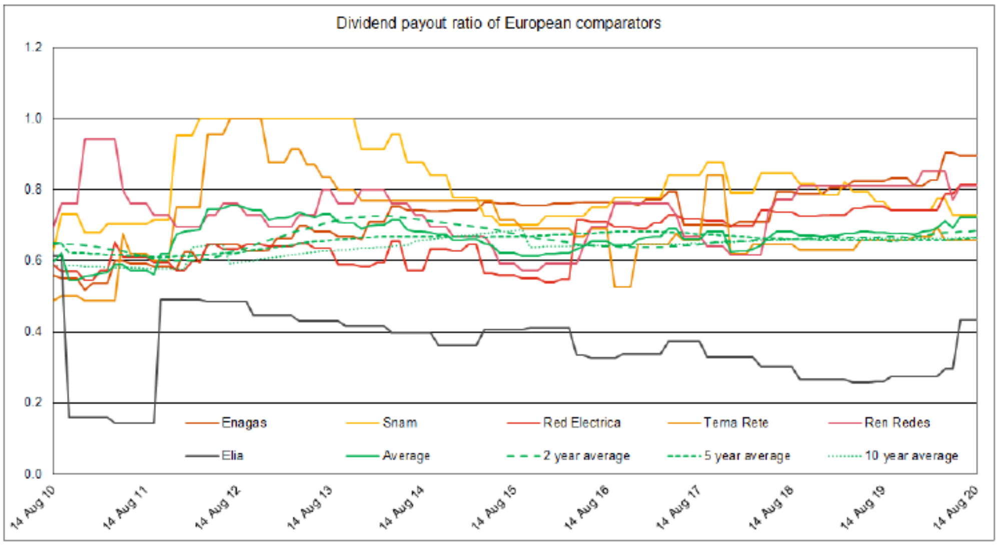
In reality SSE and NG currently have DPRs of 96% and 83% respectively, and they both averaged 76% over the last 10 years. Ofgem's estimate is based on the broad UK and European equity markets and fails to reflect the fact that many investors primarily allocate capital to utility stocks to earn income through yield instead of through growth. There are many companies within the FTSE 100 and Stoxx Europe 600 indices that do not pay a dividend as they are high growth and therefore reinvest their earnings into business growth instead of paying a cash return. It is not appropriate to use these companies to calibrate a dividend yield assumption for UK utilities.

The graph below shows the DPRs (calculated as the dividend per share divided by earnings per share) for the five UK comparators used by Ofgem and companies in asset beta analysis. The average DPR for the 5 comparators across the RIIO-1 period is between 0.7 and 0.8.



Source: Data from Refinitiv and Capital IQ

We also note that this level of DPR is not unique to the UK. We have conducted a similar analysis using European comparators where we adopt CEPAs preferred sample of Enagas, Snam, Red Electrica, Terna Rete, REN and Elia. The current average DPR of this European sample is 72%, with a 5 year historical average of 66%;



Source: Data from Refinitiv and Capital IQ

We also note that the DPRs we have calculated are marginally underestimated as we have capped all values above 1.00 to 1.00 in all of our estimates and averages. This is because in theory (and law), dividends must be paid from earnings, but in practice, significant falls in market capitalization can cause DPRs to temporarily exceed 1.00.

For reference, we provide the current DPRs for each UK and European company discussed above, as well as the 2 year, 5 year and 10 year averages.

Table 2: Dividend Pay-out Ratios

	Current	2 year average	5 year average	10 year average
National Grid	0.83	0.81	0.77	0.76
SSE	0.96	0.93	0.82	0.76
Severn Trent	0.69	0.70	0.74	0.74
United Utilities	0.68	0.78	0.76	0.80
Pennon	0.68	0.78	0.82	0.73
UK average	**0.77**	**0.80**	**0.78**	**0.76**
Enagas	0.89	0.83	0.78	0.72
Snam	0.73	0.77	0.78	0.82
Red Electrica	0.81	0.75	0.71	0.66
Terna Rete	0.66	0.65	0.66	0.71
Ren Redes	0.81	0.81	0.73	0.74
Elia	0.43	0.29	0.33	0.35
European average	**0.72**	**0.68**	**0.66**	**0.67**

Source: Data from Refinitiv and Capital IQ

Based on the DD proposed cost of equity and outperformance wedge assumption of 25bps we view believe a reasonable dividend yield assumption for the notional company is between 4 and 4.5%. The top end of the range is based on the midpoint of the high DPR (78%, see table above) and low DPR (66%, see European 5 year historical average) of the UK and European comparators of 72%. A 72% pay-out of a nominal equity return of 6.2% (I.e. excluding the outperformance wedge) is approximately 4.5%.

The lower end of the range is informed by the lowest dividend pay-out ratio in the table above (I.e. the 5-year European average). A 66% pay-out of a nominal equity return of 6.2% is 4.09%, which we round down to 4%.

We therefore view that a more valid notional dividend yield assumption, which is calibrated using a reasonable set of comparators and it consistent with Ofgem's beta analysis, is between 4% and 4.5%.

Type 4 – New evidence presented on an appropriate level of dividend yield

6.11.6 Notional equity issuance costs

As shown in the table below from our December Business Plan submission, evidence from UK equity issuances shows an average total cost of issuance of 4.6% for transactions of £250m-£750m, which we believe are representative of the scale of GDN issuances to re-lever to a notional gearing of 60%. Further factors need to be considered when setting equity issuance costs allowance;

- its highly unlikely that equity raised will be injected at exactly the same time as a bond matures. Equity funding would be issued ahead of a bond maturity and there will be a cost associated with managing that debt liability, either through a debt buy-back ahead of maturity or a cost of carry associated with a grossed up funding position until the debt matures.
- there will also be significant internal costs of equity issuance

Type 4 – New evidence presented on an appropriate level of notional equity issuance costs

Therefore, we believe that the notional equity issuance allowance should be at least the 5% level proposed by Ofgem

Market equity issuance costs for transactions between £250m-£750m since 2016

Pricing Date	Company	Deal Value (£m)	Est. Net Proceeds (£m)	General Industry	Deal Type	% of Company Sold	Est. Total Cost of Offering (%)	Underwriting Fees (%)
13-Jun-19	Marks & Spencer	601	571	Retail	Rights Offer	16.7%	5.1%	2.0%
21-May-19	Sirius Minerals	327	311	Chemicals	Cash Placing	31.3%	4.9%	3.8%
17-May-19	Metro Bank	375	363	Finance	ABB	43.5%	3.2%	2.5%
18-Dec-18	Grainger	349	332	Real Estate	Rights Offer	31.8%	5.0%	2.5%
14-Dec-18	Restaurant Group	319	305	Dining & Lodging	Rights Offer	59.1%	4.4%	2.8%
11-Jul-18	ITE Group	267	250	Professional Services	Rights Offer	63.6%	6.4%	2.3%
10-Apr-18	Provident Financial	331	300	Finance	Rights Offer	41.5%	9.4%	2.8%
04-Dec-17	Assura	330	319	Real Estate	Cash Placing	22.9%	3.3%	2.5%
05-May-17	Cobham	521	497	Defense	Rights Offer	28.6%	4.6%	2.3%
25-Apr-17	Tullow Oil	625	607	Oil & Gas	Rights Offer	33.8%	2.9%	2.5%
28-Mar-17	SEGRO	577	556	Real Estate	Rights Offer	16.7%	3.6%	2.3%
27-Feb-17	RPC Group	560	540	Chemicals	Rights Offer	20.0%	3.6%	2.0%
21-Dec-16	Greencore Group	451	427	Food & Beverage	Rights Offer	40.9%	5.4%	2.3%
24-Nov-16	Sirius Minerals[1]	370	352	Chemicals	Cash Placing	44.4%	4.9%	4.5%
09-Nov-16	Phoenix Group	742	718	Insurance	Rights Offer	39.1%	3.2%	2.3%
17-Jun-16	Cobham	507	487	Defense	Rights Offer	33.3%	3.9%	2.3%
Average		*453*	*433*			*35.4%*	*4.6%*	*2.6%*

Source: SGN 's financial advisors

6.11.7 Pension scheme established deficit funding

SGN believe the established pension principles should be rolled forward to RIIO-2. We agree with the approach to update forecast costs in line with the outcome of the 2020 pension reasonableness review, which is due to conclude in November 2020.

6.11.8 Annual iteration process

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?

As detailed below we don't believe there is a one-size-fits-all answer. Instead, we believe a bank rate plus a margin is the more suitable interest/discount rate when a company can reasonably be expected to accommodate the movement of relatively minor cashflows across years via a short-term bank facility (or equivalent). In contrast we believe cost of capital ought to be used when timing adjustments entail a more substantial investor commitment and/or take effect over a longer duration, for example when investment expenditure is not known when allowances are set 'ex ante' at Final Determination, including re-openers and uncertainty mechanisms.

Due to the significant delay in funding, the payback of the 25bps allowed vs expected returns wedge, if the sector does not outperform the RIIO-2 price control, should also be subject to a cost of capital time value of money adjustment. Finally, in line with the interest rate calculation, the cost of capital applied for time value of money adjustments should also be a nominal figure.

As evidenced in First Economics report 1, we don't believe there is a one-size-fits-all answer. Instead, we believe a bank rate plus a margin is the more suitable interest/discount rate when a company can reasonably be expected to accommodate the movement of relatively minor cashflows across years via a short-term bank facility (or equivalent). In contrast we believe cost of capital ought to be used when timing adjustments entail a more substantial investor commitment and/or take effect over a longer duration, for example when investment expenditure is not known when allowances are set 'ex ante' at Final Determination, including re-openers and uncertainty mechanisms.

It has long been regulatory practice to recognise the financing costs of such expenditure incurred due to investors needing to finance deferments of revenues, instead of investing elsewhere, when there is no matching revenue being received from customers. This is very much akin to capitalised ex ante allowances being added to the RAV and earning the allowed WACC before they are funded (via depreciation) by customers. It is not clear why investors funding deferments of revenues due to uncertainty mechanisms or re-openers would be any different to investors funding deferral of investment on the RAV, as the movements in uncertainty mechanisms from the final determination, or re-openers, is simply because there is not enough certainty to put the expenditure on the RAV in the year in question.

Naturally if less investor funding is required, due to uncertainty mechanisms out turning lower than required, then the investor financing cost saving should also be at the cost of capital. CEPA, in its July 2020 paper[580] for Ofgem, makes the argument that Ofgem's treatment of prior-year adjustments may entail a different, lower level of risk for companies compared to the main allowed cost of capital;

> *'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.'*

The fact that the risk was in the past does not mean that it hasn't been incurred. 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 instalments over the regulatory lifetime of the asset. When Ofgem rolls over its RAVs 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 been incurred but still, quite rightly, gets funded.

Due to the significant delay in funding, the payback of the 25bps allowed vs expected returns wedge, if the sector does not outperform the RIIO-2 price control, should also be subject to a cost of capital time value of money adjustment.

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

Subject to the points raised in FQ31 and FQ32 we have no objections to the approach and methodology used to calculate the margin.

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[580] CEPA (2020), Priory Year Adjustment Uplifts

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?

As set out in our response to FQ31 we believe time value adjustments for more substantial investor commitments and/or those time value adjustments that take effect over a longer duration should be based on the cost of capital, due to investors needing to finance deferments of revenues. Uncertainty mechanisms, re-openers and payback of the 25bps allowed vs expected returns wedge, if the sector does not outperform the RIIO-2 price control, are all examples of this.

As also stated in the response to FQ31 if less investor funding is required, due to uncertainty mechanisms out turning lower than required, then the investor financing cost saving should also be calculated at the cost of capital.

Finally, in line with the interest rate calculation, the cost of capital applied for time value of money adjustments should also be a nominal figure.

Type 4 – New evidence presented on an appropriate methodology for time value of money adjustments

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

There needs to be caution, when considering implementing such a change, that any benefits to customers outweigh the burden of such a change on the energy networks. It needs to be considered why this change is being proposed given the current arrangements were implemented for RIIO-1 to introduce more certainty on price levels. The impact of new funding mechanisms, volume drives and uncertainty mechanisms on this proposal also needs to be assessed. Therefore, due to all these factors, we would strongly recommend a detailed impact assessment for any change is implemented.

Also, it does seem highly likely that under/over recovery would increase under these proposals, as currently due to a two year lag on most applicable items the under/over recovery for GDNs is mostly driven by variations in collected income from that forecasted when setting the tariffs. Therefore, under/over recovery limits will need to be thoroughly reviewed.

Type 4 – New evidence presented the proposal to include forecasts for most PCFM variable values

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.

It is important to understand the full range of plausible outcomes in RIIO-2 and the impact these may have on financial resilience. Initial modelling shows an adverse impact on credit metrics and this risk needs to be incorporated in the overall financeability assessment

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?

We are concerned with a specific requirement to disclose personal data and information for publication and believe it is not one that Ofgem should impose and risks cutting across the requirements of good corporate governance. It is also important to recognise that an increasing proportion of the group success is determined by an increasing share of the unregulated business in overall group turnover.

SGN is signed up to the WATES principles. Under this the executive pay is identified by the concept of ‘appropriate officers’ as a collective. It is our view that this is appropriate and provides an appropriate level of transparency.

In addition, as we set out in our business plan, the targets and any associated bonus that are payable are based on the balanced score card approach. Finally, we highlight that we are comfortable to disclose our dividend policy.

Type 4 – New evidence presented on proposed additional reporting requirements on executive pay/remuneration and dividend policies

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

SGN are unclear why total allowed revenue is not used for ODI caps and collars, minus ODIs to avoid circularity. As set out in our response to FQ38 this can be based on allowed revenue used in setting the final tariffs for the year ahead, so targets are set using the latest information but are known before the year in question.

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

SGN don't think this proposal is appropriate given the amount of allowances moved into uncertainty mechanisms and re-openers. The simplest solution would be to base the caps and collars on the allowed revenue used in setting the final tariffs for the year ahead, so targets are set using the latest information but are known before the year in question, in line with option C in para 11.102 of the DD Finance Annex. Regardless of the mechanism used it needs to be confirmed that the cap/collar will be in nominal prices.